STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	**13-0546**
Petition for Approval of the 2014 IPA Procurement Plan pursuant to Section 16-111.5(d)(4) of the Public Utilities Act.	**:**	

ORDER

DATED: December 18, 2013

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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" or "ICC") websites. Among other things, the purpose of the power procurement plan is to secure electric power and energy 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" or "Ameren"). 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 30, 2013, the IPA filed with the Commission its sixth annual power procurement plan ("Plan," "IPA Plan" or "IPA 2014 Procurement 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 30, 2013; thus, the deadline is December 30, 2013. 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 30, 2013, the following entities filed petitions for leave to intervene: AIC; ComEd; the Renewables Suppliers ("RS") the Citizens Utility Board ("CUB"); the Natural Resources Defense Council ("NRDC"); Dynegy Midwest Generation, LLC and Dynegy Kendall Energy LLC (jointly "Dynegy"); the Department of Commerce and Economic Opportunity ("DCEO"); Exelon Generation Company, LLC ("Exelon"); Illinois Competitive Energy Association ("ICEA"); Retail Energy Supply Association ("RESA"); and Wind on the Wires ("WOW"). The City of Chicago ("City") and the People of the State of Illinois by the Office of the Attorney General ("AG") each filed an appearance in this proceeding, and the Commission Staff ("Staff") also participated.

On October 7, 2013, Objections to the Plan were filed by the RS, the AG, ComEd, AIC, Exelon, ICEA, RESA, WOW and DCEO.[1]

Parties were notified that pursuant to Section 16-111.5(d)(3) of the PUA, no hearing in the above-referenced matter was determined to be necessary.

Pursuant to a schedule issued by the Administrative Law Judge, Responses to Objections were filed by the IPA, AIC, WOW, the AG, Staff, Exelon, RESA, CUB, ComEd, ICEA and DCEO.[2] Thereafter, Replies to Responses were filed by the above-named Intervenors except the AG, and by the RS and NRDC.

On November 13, 2013, a Proposed Order was served on the parties. Briefs on Exceptions ("BOE") were filed by the IPA, Exelon, RESA, the RS, NRDC, CUB, Staff,

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[1] DCEO emailed its Objections to some parties on October 8, 2013 but did not provide a copy to the Administrative Law Judge. Additionally, DCEO's Objections did not appear on e-Docket until October 21, 2013.

[2] On October 21, 2013, DCEO file a Motion to file Instanter and Response to Objections. On October 31, 2013, DCEO filed a Verified Motion to file a Response to Objections Regarding the 2014 IPA Procurement Plan.

ICEA, AIC, the AG, ComEd, and DCEO,[3] Briefs in Reply to Exceptions ("RBOE") were filed by the IPA, RESA, ICEA, Exelon, CUB, ComEd, the AG, AIC, WOW, DCEO, and Staff.

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

This section of the Order describes the IPA's Plan as filed on September 30, 2013, 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.

The IPA reports that eligible retail customers generally are residential and small commercial fixed price customers who have not chosen service from an alternate supplier. The Plan considers a 5-year planning horizon that begins with the 2014-2015 delivery year and lasts through the 2018-2019 delivery year. The IPA also indicates that the fifth plan developed by the IPA, and approved by the Commission in ICC Docket No. 12-0544, was the first plan that recommended no procurement of electricity or renewable resources for the utilities. It was also the first plan that included incremental energy efficiency programs as mandated by Section 16-111.5B of the PUA. The decision not to conduct any procurement of electricity in calendar year 2013 was a reflection of the monumental changes in the Illinois electricity markets brought about by the rapid increase in customer switching due to retail competition and municipal aggregation.

Although switching led the portfolio considered in last year's plan to be long and thus without procurement needs, the IPA says this Plan recommends a return to electricity procurements to address supply shortfalls and switching risk. The IPA indicates that this conclusion is based on the IPA's analysis of the load forecast scenarios, the expiration of existing supply contracts, and the IPA's analysis of the risks associated with serving electric load and the various factors of power procurement. The Plan continues to recommend no procurement of renewable resources for the utilities because current targets are being exceeded and the statutory rate caps preclude any

[3] DCEO served its BOE on parties on November 21, 2013, but it was not filed on e-Docket. On December 2, 2013, DCEO filed a Motion to file its Brief on Exceptions *instanter*.

additional procurement. The IPA states that the Plan also continues to recommend no sale of renewable resources for existing quantities in excess of targets.

According to the IPA, the accelerated switching of load to competitive supply associated with governmental aggregation, which led to no procurement in 2013, is unlikely to continue at the same accelerated pace as has been seen since roughly 2011. The IPA believes that market saturation coupled with decreased headroom for competitive suppliers will drive any slowing or reversal of municipal aggregation gains. Most, though not all, of the large blocks of load that could switch have now done so and any likely additional load switching will come from ongoing retail marketing. The IPA says available headroom has diminished as a consequence of the utilities' current supply portfolio's lower price relative to market; it is now significantly closer to market price. As a consequence of these factors, the IPA reports that the supply strategy presented in the Plan takes the cautious view that expiring municipal aggregation contracts provide switching risk that the IPA must account for when considering what procurements to propose for eligible retail customers. To mitigate that risk, the IPA proposes a second procurement event to be held in September 2014 unless ComEd's load drops significantly below current projections and other factors determine that a second procurement is not cost-effective. In the event a second procurement is held, the parties shall rely on the same contracts and letter of credit forms used for the initial procurement in April 2014.

The IPA proposes to continue using the procurement strategy that the IPA has historically utilized (hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach). The IPA says it investigated alternative strategies such as full requirement contracts or use of options; however, the IPA believes the continuation of the IPA's past strategy at this time to be the most prudent and the most likely to produce its statutorily mandated objective to develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

Based on the analysis of the costs of procurement in Chapter 6 and supply shortfalls identified in Chapter 4, the IPA makes several recommendations for procurements for delivery year 2014-2015. The IPA recommends decreasing the size of procurement blocks from 50 megawatts ("MW") to 25 MW. The IPA indicates the hedging strategy is revised to bifurcate the first delivery year into two periods with different hedging levels. The summer would be "fully hedged" at the time of the April procurement and the balance of the year 75% hedged. The IPA recommends the Commission pre-approve a supplemental September procurement which would bring the hedging level for the rest of the first delivery year to the "fully hedged" level. The IPA says approval would be based on factors intended to ensure that the benefits of the September procurement outweigh the costs of running the procurement. The strategy for years two (delivery year 2015-2016) and three (delivery year 2016-2017) reflects lower forward hedging strategies when compared to prior plans. The IPA's proposed overall strategy is designed to manage the risk of load uncertainty resulting from the possibility of large blocks of load returning to the utilities because of municipalities choosing not to continue their aggregation programs.

The IPA continues to recommend that capacity, ancillary services, load balancing services, and transmission services be purchased, as they are now, by Ameren from the Midcontinent Independent System Operator, Inc. (“MISO”) (f/k/a Midwest Independent Transmission System Operator, Inc.) marketplace and by ComEd from the PJM Interconnection, L.L.C. (“PJM”).

The IPA states that the load forecasts supplied by the utilities on July 15, 2013 indicate that existing renewable energy resources under contract exceed the Renewable Portfolio Standard obligations for eligible retail customers. Separately, the statutorily mandated rate caps also lead the IPA to recommend that the Commission approve a curtailment of the long-term power purchase agreements that were entered into as part of the 2010 procurement plan based on utility load forecast updates in Spring 2014. The IPA says this is essentially the same as was adopted in last year’s plan. To mitigate the impact of those curtailments the IPA also recommends the use of Alternative Compliance Payments collected from customers on hourly pricing to purchase some or all of the curtailed Renewable Energy Credits (“RECs”). While not subject to Commission jurisdiction, the IPA plans to use funds from the Renewable Energy Resources Fund ("RERF") to purchase any remaining curtailed RECs.

The following tables summarize the IPA’s proposed hedging strategy and the IPA’s proposed 2014 procurements:

2014 Hedging Strategy

April 2014 Procurement			**Sept. 2014 Procurement**
June 2014- May 2015 (Upcoming Delivery Year)	Upcoming Deliver Year + 1	Upcoming Delivery Year + 2	November 2014-May 2015
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

IPA Recommendations Based on July 15, 2013 Load Forecasts

	Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
	2014-15	Up to 175 MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS[4] procurement: target exceeded (except solar and DG[5]),	Will be purchased from MISO

[4] Renewable Portfolio Standard is abbreviated as "RPS" in the remainder of this Order.
[5] Distributed Generation is abbreviated as "DG" in the remainder of this Order.

A M E R E N				budget cap exceeded	
	2015-16	Up to 150 MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2016-17	Up to 150 MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2017-18	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2018-19	No energy procurement required	Direct purchase from MISO capacity market	Shortage of 10 GWh[6] but budget cap exceeded: no RPS procurement	Will be purchased from MISO
	Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
	2014-15	Up to 1,175 MW forecasted requirement (April Procurement) Up to 350 MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	Shortage of 116 GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

[6] Gigawatt-hours is abbreviated as "GWh" in the remainder of this Order.

COMED	**2015-16**	Up to 375 MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2016-17	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2017-18	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2018-19	No energy procurement required	Direct purchase from PJM capacity market	Shortage of 178GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

The IPA reports that the current Plan is the second year of inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the PUA. The IPA recommends inclusion of the programs submitted by the utilities that have passed the Total Resource Cost Test ("TRC"). The IPA further suggests consideration be given to issues relating to other third-party programs that the utilities did not include in their savings goals but that the IPA believes should be presented by the IPA to the Commission. Finally, the IPA recommends that the Commission adopt the recommended policies laid out by the IPA to address open questions involving incremental energy efficiency procurement, including adoption of certain consensus items from recent workshops relevant to the Section 16-111.5B procurement process.

The IPA recommends the following items for Commission action:

1. Approve the base case load forecasts of ComEd and Ameren as submitted in July 2013.

2. Require the utilities to provide an updated March 2014 forecast which will be pre-approved by the ICC in this docket subject to the March 2014 consensus of each utility, the IPA, ICC Staff, the Procurement Administrator(s) and the Procurement Monitor.

3. Approve two energy procurements. The first in April 2014, the second in September 2014. The September procurement will be held subject to a July 2014 forecast indicating a hedging shortfall exists for the prompt year,

a determination that the estimated hedging benefit exceeds the cost of the procurement, and other conditions as specified by the Commission.

4. Require the utilities to expand the July 2014 forecast to include the November 2014 to May 2015 period. The addition of the November 2014 through May 2015 forecast will be used solely in determining the quantity of energy to be solicited, if applicable, in the September 2014 procurement event and will have no bearing on the renewable curtailment.

5. Approve continued procurement by ComEd and Ameren of capacity, network transmission service and ancillary services from their respective regional transmission organization ("RTO") for the 2014-2015 delivery year.

6. Approve pro-rata curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy, subject to the updated March 2014 forecast. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the aforementioned parties. Otherwise, the July 2013 forecast will form the basis for curtailment.

7. Approve the use of hourly Alternative Compliance Payments funds to buy curtailed RECs. Approve the Section 16-111.5B incremental energy efficiency programs submitted by the utilities.

8. The IPA also identified additional energy efficiency programs which were not included in the savings goal for the Commission to consider and approve as appropriate.

9. Approve and adopt the solutions to open Section 16-111.5B energy efficiency procurement issues recommended by the IPA, or as modified in response to stakeholder input. These recommendations include which programs the IPA must provide to the Commission, and then which programs the Commission may or should not approve.

A. Load Forecasts

Load forecasts are addressed in Section 3.0 of the IPA's Plan. AIC and ComEd are required by Section 16-111.5(d)(1) of the PUA to provide five-year planning forecasts, which is June 2014 to May 2019 for the 2014 Procurement Plan. The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the IPA. The IPA notes that the Commission is required to approve the Plan, including the forecasts on which it is based. The IPA says it must review and evaluate the load forecasts to ensure they are sufficient for the purpose of procurement planning. In doing so, the IPA first reviewed the forecasts from July 2012, to determine if the form and content of those forecasts support the analyses the IPA plans to undertake this year. The IPA says it and its consultant put a series of questions to the utilities. A similar process was then applied to the July 2013 forecasts.

The IPA states that, according to Ameren, switching, in particular municipal aggregation, is the greatest driver of load uncertainty. A wave of switching is expected in the summer and early autumn of 2013, driving the switched load to about 65-70% of residential and small commercial load. The IPA indicates a low-load scenario would involve a higher level of switching, possibly a fourth wave of referenda leading to 95% switching, so that Ameren would retain only 5% of the residential and small commercial customers.

On the other hand, the IPA notes a large portion of the initial set of municipal aggregation contracts will be expiring in mid-2014. The IPA says the price for utility energy supply lags the market price of energy, because the IPA's portfolios are laddered (bought over a period of several years). As the market price fell, the IPA claims the utility price lagged and was above market; but as the market price of energy rises, new aggregation contracts will appear more expensive than utility supply. According to the IPA, rising market prices could motivate a significant return to utility service beginning with the 2014-2015 procurement year.

The IPA indicates that ComEd's high and low switching cases are not as extreme as Ameren's, and are based on specific event-related assumptions. The IPA says the high switching (low load) case assumes an additional round of municipal aggregation referenda resulting in the departure of an additional 10% of load, and additional switching to alternative retail electric suppliers ("ARES").

1. Load Forecast Uncertainty

The IPA states that in the past, it has procured or hedged power for the utilities to meet a forecast of the average hourly load in each of the on-peak and off-peak periods. The IPA says it has addressed the volatility in power prices by "laddering" its purchases, hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the delivery year. Even if pricing two years ahead were extremely advantageous, the IPA believes it should not purchase its entire forecast that far ahead because the forecast is itself uncertain. The IPA believes it is important to understand the sources of uncertainty in the forecasts.

The IPA asserts that even if it could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. The IPA notes that load varies from hour to hour. Energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. According to the IPA, a perfect hedge would cover differing amounts of load in different hours, and would have to be based on a forecast of the different hourly loads. The "expected hourly load" is not an accurate forecast of each hour's load. The IPA claims this is not an issue of uncertainty: it would be true even if the expected hourly load were a perfect forecast of the average load, and the hourly profile (the ratio of each hour's load to the average) were known with certainty. As a result, the IPA treats it together with the other uncertainties.

According to the IPA, both utilities construct their load forecasts by forecasting load for their entire delivery service area, then forecasting the load for each customer class or rate class within the service territory, and then applying multipliers to eliminate load that has switched to municipal aggregation or other ARES service. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely, as the utilities have no supply or planning obligation for them.

The IPA indicates that Ameren does not explicitly address uncertainty in load growth. In other words, they do not define "load growth scenarios" and examine the consequences of high or low load growth. The IPA says Ameren addresses both load and weather uncertainty by defining high and low scenarios at particular confidence levels of the model fit, that is, of the residuals of their econometric model. The high and low cases, which represent the combined and correlated impact of weather and load growth uncertainties, represent a variation of only ±9% in service area load. The IPA notes that Ameren's high and low cases also include extreme customer migration uncertainty.

The IPA states that ComEd defines high and low load growth scenarios as 2% above or below the load growth in their base or expected case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios so it is hard to determine how they relate to economic uncertainty. Given the stability of utility loads in recent years, the IPA believes the differences of ±/2% in load growth should represent a good range of uncertainty.

On a short-term basis, the IPA says weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The IPA indicates that Ameren and ComEd have incorporated weather variation into their high and low load forecasts. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. The IPA says much of the impact of weather is on load variability within the year.

According to the IPA, in their base cases, Ameren projects 73.0% switching by eligible retail customers by the end of the 2014-5 procurement year and ComEd projects about 74.7%. The IPA believes this may be approaching a saturation level; switching levels are so high that there is not much "headroom" for upwards uncertainty, and suggest that currently there are no aggregation referenda scheduled for November 2013.

At this point, the IPA asserts the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase from return to service or opt-out. In July 2012, ComEd assumed a 4% opt-out rate but later in the year, based on experience, it raised the assumption to 8% for single-family residential customers and 12% for multi-family customers (still 4% for non-residential customers). Ameren assumed a 10% opt-out rate in its load forecast computations.

The IPA indicates that over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. The IPA suggests that many of the renewal offers made by the suppliers to municipal aggregations may be out of the money relative to utility bundled supply prices, so there may be a considerable amount of return to utility service. The IPA believes this is especially true if market prices rise between now and the expiration of municipal aggregation contracts. On the other hand, switching could be higher than expected resulting in an over-hedged position. Expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. The IPA says both Ameren and ComEd have assumed a wide range of switching fractions in their low and high scenarios. The IPA notes that some multi-year municipal aggregation contracts may have early termination clauses if the supplier cannot match or beat the utility-offered supply price.

In the IPA's view, customer migration behavior is particularly important because of its linkage with market prices. The IPA says utility retail tariff prices tend to lag prices in the power market for two reasons. First, the IPA’s procurement strategy has been to buy power in a “laddered” fashion. A large fraction of the power consumed by retail customers would have been bought forward one to two years earlier. The IPA states that in a period of rising prices, those forward purchases would have been priced below the current spot price (and below the current forward price), and therefore the blended price of IPA supply would be less than the current price of a new contract, e.g., a renewed municipal aggregation contract.

The IPA also indicates the reverse is true in a period of falling power prices, as has been experienced over the last several years: the blended price of IPA supply would be higher than the contemporary price of power, or the price of new contracts. According to the IPA, that would motivate rational consumers to depart from utility service for the price of a new contract either with an ARES or through municipal aggregation. If the market is moving into an environment of rising power prices, it is equally true that consumers would be motivated to return to utility service. The forward contracts in the utilities’ portfolios for 2014-2015 are currently above the forward curve (out of market).

As for the second reason, the IPA notes there are regulatory lags involved in utility rate setting. Even if the IPA supply were purchased entirely at the spot price, the monthly retail price would have been set in advance and reconciled after the fact. In a rising market the tariffs will be below the actual supply cost. The IPA says customers do eventually pay those higher prices, through a delayed balancing account mechanism. The IPA asserts that price caps, such as the ceiling on ComEd’s Purchased Energy Adjustment, introduce further delays. A customer who aggressively exercises his or her switching options would leave utility service when spot prices begin to fall to obtain a more immediate benefit from the price reduction, and return to utility service when prices begin to rise, since he or she would be insulated from that rise for at least several months. The IPA suggests customers may not be so aggressive in switching, and that aggressiveness may also be mitigated by regulatory and legal barriers, such as the prospect that they may have to stay on utility service for 12 months if they do not select a new supplier within two billing periods of returning to utility service.

The IPA asserts that although it is not yet clear how governments running municipal aggregation programs and individual customers who may opt out or leave a program will act, it is likely that customers would return to utility service in periods of rising prices. The IPA says it and the utilities would have to arrange for additional supply to cover the returning load, at a price higher than was paid for the originally forecasted load and higher than would be built into utility tariffs. The IPA believes that load whose return is correlated with high prices (and whose departure is correlated with low prices) represents not only load uncertainty but also an absolute price risk.

The IPA states that independent of market pricing, there may be other market arrangements that motivate customers to switch from or return to utility service. Some customers, or customers in some locations, may be inherently less expensive to serve and will see a benefit from moving to a retailer that can provide them a differentiated price. The IPA suggests that others, who may find they are more expensive to serve, will be motivated to return to the uniform tariff. Customers may not have realized these differences when the initial municipal aggregation referenda were held; the costs may actually be utility delivery charges that only become visible when customers leave bundled service. The IPA suggests that, for example, ComEd's current practice uses four different peak load contributions ("PLCs") – one for each of the four sub-classes of residential customers. Each of these constant PLCs is the same for all customers within the sub-class, regardless of other measures of the customer's "size." Low-usage customers or aggregation groups dominated by low-usage customers will find that they are disadvantaged by ARES or municipal aggregation service, relative to bundled service. The IPA is interested in stakeholder feedback on the effect and magnitude of non-market price factors leading to government and individual decision-making.

According to the IPA, although switching from the utility to ARES by individual customers has some impact, Ameren and ComEd switching forecasts have been dominated by municipal aggregation. The IPA asserts that the most desirable customers to ARES would be medium and large commercial and industrial customers. Since their load has been declared competitive they are not eligible for IPA-procured default rate service. Although the IPA recognizes that many ARES do focus on individual residential switching, the IPA is not aware of a way to model or predict how many customers will leave default service for a non-municipal aggregation ARES. In the absence of such a model, the IPA claims it is reasonable to assume that switching behavior by individual customers will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation.

The IPA notes that customers who could have elected bundled utility service but take electric supply pursuant to an hourly pricing tariff are not “eligible retail customers.” Therefore, the IPA says these hourly rate customers are not part of the utilities’ supply obligation and the IPA does not have to procure energy for them. Ameren and ComEd did not include customers on hourly pricing in their load forecasts; they appropriately considered these customers to have switched. The IPA believes the amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts.

The IPA states that Public Act 95-0481 also created a requirement for ComEd and Ameren to offer cost-effective energy efficiency and demand response measures to all customers. Both Ameren and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with the Procurement Plan. The IPA says these programs are reflected in the load forecasts.

The IPA says that as noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources.

According to the IPA, many of the most effective emerging technologies and rate options depend on the installation of “smart meters.” When the 2013 Procurement Plan was produced, the Commission had not yet approved the AMI deployment plans for Ameren and ComEd. The Commission approved a revised deployment plan for Ameren in December 2012 in which 15% of its meters will be upgraded to AMI by the end of 2015 and a revised AMI deployment plan for ComEd in June 2013 in which 900,000 AMI meters (out of 4.03 million, about 22%) will be installed by the end of 2015. Given the necessary lag between the time that meters are installed and the point at which customers are able to make use of them with new technologies or rates, the IPA believes it is likely that less than 22% of ComEd customers, and less than 15% of Ameren customers, will be able to make use of smart meters by the end of the 2015-2016 procurement year. The IPA says the load uncertainty associated with AMI meters and related technologies should be low for the first half of the projection horizon.

In the IPA's view, electric vehicles ("EVs") have the potential to significantly impact electricity demand. The IPA states that while their prices have been declining, they remain expensive and of limited range. The IPA says one promising spur to adoption was battery-swapping technology. The IPA suggests that optimism about EVs must be tempered by the price of EVs, the difficulties that have faced some manufacturers, and supply limitations.

The IPA says the 2013 Procurement Plan included estimates from Ameren and ComEd totaling no more than 536,000 EVs on the road in Illinois by 2020 (the projection horizon for this Plan extends to 2019) and a second estimate of 300,000 megawatt-hours ("MWh") of additional load per 100,000 electric vehicles. The Plan forecasted an increase of 1.6 TWh of annual load by a year after the end of the projection horizon.

The IPA asserts actual EV load will probably be much lower. The IPA suggests that this figure should be compared with the total residential and small commercial load in Ameren and ComEd service territory, which is forecasted to be over 82 TWh in the 2018 procurement year. Although EVs are a promising technology, the IPA believes they do not appear to significantly contribute to load forecast uncertainty during the projection horizon of this Procurement Plan.

The IPA recommends adoption of the Ameren and ComEd base case load forecasts, both of which include incremental energy efficiency programs. According to the IPA, the high and low cases represent useful examples of the extent to which load can vary. Although they are primarily driven by variation in switching, the IPA says Ameren correctly notes that this is the major uncertainty in its outlook. The IPA asserts that the switching variability, especially in Ameren's high and low forecasts, is extreme and thus these may be characterized as "stress cases." The IPA's procurement strategy to date has been built on hedging the average hourly load in each of the peak and off-peak sub-periods, and the high and load cases represent significant variation in those averages.

The IPA indicates that Ameren low and high load forecasts are on average 63% lower and 117% higher during the 2014-2015 Delivery Year relative to the expected, base forecast. Comparatively, ComEd low and high load forecasts are 15% lower and 47% higher than the expected base forecast. The IPA says this reflects the differences in switching assumptions used by the two utilities.

The IPA suggests another use of the high and low cases will be to estimate the risks of different supply strategies. According to the IPA, a key driver of that risk is the cost of meeting unhedged load on the spot market. One of the main reasons load is unhedged is that one attempts to hedge a variable or shaped load with a product whose delivery is constant. The spot price at which the unhedged volumes are covered is positively correlated with load. The IPA says high and low cases are less suitable for such a risk analysis.

The IPA asserts that the high load factor of the ComEd base case forecast implies that the hourly profile of that case is not representative of a typical year. This means that the base case hourly forecast would understate the amount by which hourly loads vary from the average hourly loads in the peak and off-peak sub-periods. The IPA says using that hourly profile for a risk analysis could lead to underestimating the cost of unhedged supply.

The Ameren load scenarios have identical monthly load shapes (differing by uniform scaling factors). The IPA claims these shapes will not provide much information about the cost of meeting fluctuating loads, except for the information contained in the expected load shape. The expected load shape may have an overstated load factor like that of ComEd, and no other forecast case is available for comparison.

According to the IPA, the extreme nature of Ameren's low and high load forecasts can influence the results of a probabilistic risk analysis. The IPA avers that with almost any assignment of weights to the Ameren cases, load uncertainty will dominate price uncertainty. The IPA says this does not apply to ComEd, which must be taken into account when evaluating any simulation of procurement risk.

The IPA says ComEd informed it that ComEd assessed the variation in delivery service load (before considering switching) in the high and low cases as representing the 75th to 80th percentile and 20th to 25th percentile, respectively. In its probabilistic analysis the IPA treated ComEd's high and low forecasts of retained load as representing the 95th and 5th percentile points of an underlying load distribution. The IPA says Ameren had described the high and low delivery service forecasts as being the 80th to 90th and 10th to 20th percentiles respectively, and the associated switching forecasts were also more extreme, so the IPA treated Ameren's high and low forecasts of retained load as the 97.5th and 2.5th percentiles of an underlying distribution.

2. Existing Resource Portfolio and Supply Gap to Be Filled

The IPA has historically purchased supply in standard 50MW on-peak, off-peak, and around-the-clock blocks. The IPA says these purchases are driven by the supply requirements outlined in the current year Procurement Plan and are executed through a competitive procurement process. This procurement process is administered and monitored for the Commission by independent third parties.

In addition to purchasing block contracts, the IPA says Ameren and ComEd rely on the operation of their RTOs (MISO and PJM, respectively) to balance their loads and consequently incur additional costs. During on-peak hours, purchased energy blocks may not fully cover the load therefore triggering the need for spot energy purchases from the RTO. Similarly, during off-peak hours over-supply may occur, prompting the utilities to sell their excess energy to the RTOs at a low off-peak hour price. The IPA notes that ComEd is currently under-hedged in every hour of the June 2014 to May 2019 period relative to the expected forecast and (absent additional purchases) would be expected to rely on the operation of PJM in every hour to meet its load.

The IPA says its procurement plans are based on a supply strategy designed, among other things, to manage price risk and cost. The underlying principle of this supply strategy is to procure energy products that will cover all or most of the near-term load requirements and then gradually decrease the amount of energy purchased relative to load for the following years.

The IPA notes that prior to the 2013 Procurement Plan, the first year of the 3-year procurement plan was hedged at 100%, while the second and third years would only be hedged at 70% and 35%, respectively. As part of the 2013 Procurement Plan and based on suggestions from Commission Staff, the IPA considered a revision to this strategy (for the energy products only) to account for declining market prices and accelerating customer switching. The proposal was the first year would be hedged at

75%, while the second and third years would be hedged at 50% and 25%, respectively. However, because no procurement was required, the IPA recommended that the hedging strategy be revisited in future plans.

Because of the lack of visibility and liquidity of the energy markets and to limit the ratepayers' exposure to unnecessary price risk and cost, the IPA indicates it has not purchased any energy beyond a 3-year term horizon, except for long-term procurements which were mandated by the Legislature. These include:

- A 20-year bundled Renewable Energy Credit ("REC") and energy purchase, starting in June 2012, made by Ameren and ComEd in December 2010.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017; there were also associated REC procurements but they do not impact the (energy) resource portfolio.

The IPA states that due to the reductions in rate revenue attributable to customer switching, ComEd has been obliged to curtail its existing long-term renewable contracts in order to keep the cost of renewable energy resource under the statutory cap for the 2013-2014 delivery year (i.e., the year commencing June 1, 2013 and ending May 31, 2014).

According to the IPA, the Rate Stability Procurements ("RSP") mandated by SB1652, and Ameren's existing contract portfolio, including long-term renewable resource contracts (assuming no curtailments), should cover the projected load for the 2014-2015 delivery period, with the exception of the months of June, July and August. The IPA notes that additional energy will be required in 2015-2016 and beyond for Ameren.

The IPA says that under the high load forecast scenario, Ameren will be consistently short starting as early as June 2014. The average supply gap for peak hours of the 2014-2015 delivery period is estimated to be 586 MW. Under the low load forecast scenario, Ameren would not require any additional energy procurement until June 2016 and Ameren's supply portfolio would actually be in excess during the peak hours of the 2016-2017 period in average by 11 MW, and shortfalls would only occur during the summer of 2016.

According to the IPA, ComEd's current energy resources will not cover load starting in June 2014. The average supply gap during peak hours for the 2014-2015 delivery year is estimated to be 771 MW. The IPA says the 2013 Procurement Plan explicitly stated a change in the hedging plan, so that only 50% of expected 2014/2015 load would be hedged a year ahead. This gap is expected to remain relatively constant until the RSP contracts terminate in January 2018.

Under the high load forecast scenario, the IPA indicates that ComEd will be consistently short during the whole study period. The average supply gap for peak hours of the 2014-2015 delivery period is estimated at 1429 MW. Under the low load forecast scenario, the IPA says ComEd will also be consistently short during the study period except for the months of April, May and October 2017.

B. MISO and PJM Resource Adequacy Outlook and Uncertainty

In the IPA's view, as a result of retail choice in Illinois, resource adequacy (the load/resource balance) can be viewed as a function of determining what level of resources to purchase from which markets over time. The IPA states that in order for the Illinois market to properly function, the overall RTO markets (e.g., MISO and PJM) must provide sufficient resources to satisfy the load of all customers.

In reviewing the load/resource outcomes over the planning horizon, the IPA analyzed several outside studies of resource adequacy that are publicly available from different planning and reliability entities. These include:

- North American Electric Reliability Corporation (“NERC”), the entity certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- MISO, which operates the transmission grid in most of central and southern Illinois.
- PJM, which operates the transmission grid in Northern Illinois.

From review of these entities’ most recent documentation, the IPA claims it is clear that over the planning horizon both PJM and MISO will maintain adequate resources to meet the collective needs of customers in those regions.

In PJM, the IPA says capacity is largely procured through PJM’s capacity market Reliability Pricing Model (“RPM”), which was approved by the Federal Energy Regulatory Commission ("FERC") in December 2006. RPM is a forward capacity auction through which generation offers capacity to serve the obligations of load-serving entities. The IPA says primary capacity auctions, Base Residual Auctions (“BRAs”), are held each May, three years prior to the commitment period. The commitment period is also referred to as a delivery year (“DY”). In addition to the BRAs, the IPA indicates that up to three incremental auctions are held, at intervals 23, 13, and 3 months prior to the DY. According to the IPA, PJM is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with projected reserve margins averaging over 20% during this time frame. This is approximately 5% above the 15.6% reserve margin requirement.

The IPA states that MISO’s capacity market construct, Module E-1, creates a framework for electric utilities and capacity resources to enter into bilateral agreements for capacity. According to the IPA, Module E-1 is a resource adequacy program that requires the region's load-serving entities to procure sufficient capacity resources to meet their peak load plus target reserve margin. Under Module E-1, the IPA says a load-serving entity can procure resources to meet its resource adequacy requirements by offering or self-scheduling resources in the annual auction or by submitting a Fixed Resource Adequacy Plan ("FRAP") to demonstrate sufficient resources have already been procured. The IPA indicates that MISO is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with reserve margins averaging over 22% during this time. This is approximately 5% above the 17.5% reserve margin requirement.

According to the IPA, the RTO-based reliability assessments examined are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. The IPA says that while changes are projected to occur in the RTOs, the IPA concludes that it does not need to include any extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.

The IPA states that the integration of Entergy into MISO, which will create the MISO Southern Region and is planned for December 2013, will provide more generation to be dispatched and bid into the MISO markets. The IPA also says an increase in capacity resources exporting into PJM (7,500 MW in total representing an incremental 4,000 MW from the previous year's auction) is reported in the 2016/17 Base Residual Auction. The IPA believes this substantial increase in imports for PJM is a positive development with respect to PJM's capacity market, but may also indicate less confidence in MISO's Module E-1 anticipated pricing and/or liquidity to the extent imports are coming from this region.

MISO, the IPA reports, has discussed setting requirements for upward and downward ramping capacity. The concept is that at least a specified fraction of the resource adequacy would have to be met by capacity capable of meeting a flexible ramping standard. The IPA indicates that to date no such requirement has been incorporated into Module E-1.

C. Supply Risk

In the IPA's view, procurement risk factors can be divided into three broad categories: volume, price, and hedging imperfections. Volume risk deals with risk factors associated with identifying the volume and timing of energy delivery to meet demand requirements. Price risk covers not only the uncertainty in the cost of the energy but also the costs associated with energy delivery in real time. Hedging imperfections are the result of mismatches between the types of available hedge products and the nature of customer demand.

The IPA says the accuracy of load forecasts directly impact volume risk. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve.

The IPA indicates that load forecasts of both utilities start by developing a system-wide forecast. Multipliers are applied to eliminate load that has switched to ARES service or municipal aggregation. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely. The IPA says the use of a multiplier assumes the profile of non-switched load and switched load are equivalent. If the switched loads have different load shapes from the retained loads, the profiles that are the basis for the forecast do not represent actual load shapes.

The IPA states that Ameren does not explicitly separate uncertainty in load growth from customer migration and weather uncertainty, all three of which are combined in the definition of high and low scenarios. The high and low cases represent a variation of ±9% in service area load. The IPA also indicates that ComEd defines high and low load growth scenarios as 2% above or below the load growth in its base or expected case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios.

On a short-term basis, the IPA indicates that weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. Ameren and ComEd have incorporated weather variation into their high and low load forecasts. The IPA says Ameren treats weather uncertainty together with load growth uncertainty. ComEd's high and low forecasts are built around two sample years and the historical weather affects impacting forecasted load variability within the year.

In the IPA's view, the deployment of smart meters can provide customers with a better understanding of the relationship between consumption and pricing. The IPA suggests this knowledge may lead to changes in consumption patterns. It also may allow ARES to target specific customers. For example, ARES may be able to identify and target customers with flatter or more predictable loads.

The IPA states that energy efficiency programs and the introduction of customer generation can also impact consumption patterns. Weatherization and efficient appliances will reduce the total volume of energy required. The IPA says the intermittent character of small-scale wind and roof-top solar will impact both the total volume and load shape.

According to the IPA, Ameren and ComEd forecast the load to be served by subtracting from the retail load, in classes that have not been declared competitive, the fraction of load expected to be served by ARES directly or through municipal aggregation. In its base cases, the IPA says Ameren projects 73.0% switching among eligible retail customers by the end of the 2014-2015 delivery year; ComEd projects about 74.7%. The IPA indicates no additional municipal aggregation activities are forecast. At these high migration values, the IPA believes switching may be approaching saturation.

The IPA avers that the uncertainty around customer switching appears to be more related to the chance that utility load will increase from return to service. Over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. If ARES and municipal renewal offers are more expensive relative to utility bundled supply prices, the IPA believes there may be a considerable amount of return to utility service. On the other hand, the IPA suggests switching could be higher than expected resulting in an over-hedged position. The IPA says expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates.

The IPA says the price the Ameren and ComEd supply customer pays for electricity consists primarily of the price of energy procured in the forward and spot markets, the cost of capacity to meet resource adequacy requirements, and the cost of delivery, plus additional charges related to RPS compliance.

The IPA alleges that spot market electricity prices are volatile. The IPA suggests that purchasing electricity in forward markets can reduce price risk. On-peak, off-peak, and around-the-clock products are offered for various time periods from next day through several years. The IPA says the price of the hedges to be bought in each subsequent year is unknown because the future price cannot be known in the present.

The IPA states that forward contracts are based on the procurement of a block of energy over multiple hours. Customer consumption changes hourly. For example, the IPA says the portion of an energy block that is not consumed during the hour starting at 10 AM cannot be moved to the hour starting 2 PM when consumption is greater than the energy block. The day ahead forecast excess energy for the hour starting at 10 AM is sold first into the RTO’s day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. Likewise, the shortfall of energy required for the hour starting at 2 PM is purchased from the day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. The volume and price sold at 10 AM do not necessarily match the volume and price purchased at 2 PM.

ComEd, the IPA notes, is a member of PJM. The IPA notes that PJM holds annual auctions to procure capacity through its Base Residual Auction, which occurs three years and one month prior to the delivery period, and all subsequent Incremental Auctions. The clearing price for the capacity purchased through these auctions is the Final Zonal Capacity Price that PJM uses to price ComEd’s Daily Unforced Capacity ("UCAP") Obligation. According to the IPA, ComEd, like nearly all PJM Load Serving Entities, fulfills its capacity obligation through relatively passive participation in the PJM Reliability Pricing Model as a price taker. Specifically, the IPA says ComEd pays PJM the resulting Final Zonal Capacity Price times ComEd’s daily UCAP Obligation.

Ameren is a member of MISO. The IPA says MISO also has similar capacity requirement and has instituted its own Auction ("PRA"). The PRA covers the prompt year. The 2013-14 delivery year was the first year in which Ameren procured/fulfilled its

Planning Reserve Margin Requirement ("PRMR") by participating in the Auction. The IPA states that although the bulk of Ameren's Zonal Resource Credits ("ZRCs") were purchased in the 2012 procurement event, Ameren participated in the auction by offering to sell into the PRA all ZRCs acquired by Ameren through previous IPA procurement events as a price taker and received the auction clearing price. The IPA says Ameren will pay the same auction clearing price for its entire PRMR, which is updated on a daily basis to take into account retail switching.

According to the IPA, ancillary services consist of regulation to correct short-term load changes, and energy reserves to protect services from unexpected shortages. They support reliable delivery of energy. A LSE's obligation for these services can be met by self-provision, by contracting with another party, or through the RTO's reserve market. The IPA claims bilateral contracting for ancillary services is not very liquid; therefore most LSEs are exposed to the RTO's ancillary service pricing.

The IPA states that delivery of procured energy resources requires the reservation of adequate transmission capacity to transport the energy to customer locations. LSEs generally use network transmission service. Transmission service is purchased on a first-come first-serve basis. Energy contracts that call for delivery at the customer location shift transmission price risk to the seller. According to the IPA, the pricing of transmission service is FERC regulated and tends to be transparent.

Transmission congestion occurs, the IPA indicates, when the desired flow of power on a transmission path exceeds the path's capacity. The RTO runs a day-ahead market to identify and reschedule flows. The cost of this service is charged to entities scheduling delivery into a congested load zone. The IPA states that Financial Transmission Rights ("FTRs") are hedging instruments used to mitigate congestion risk and Auction Revenue Rights ("ARRs") allocate to transmission customers (both firm and network) the revenues resulting from the auction of FTRs. The IPA says LSEs can use these revenues to offset congestion charges.

The IPA observes that customer switching decisions may be influenced by the difference between utility and third-party provider pricing. The IPA says customer switching behavior impacts volume risk and variability in utility customer volume impacts price risk.

The IPA's historic procurement strategy has been to buy power in a "laddered" fashion. A large fraction of the power consumed by retail customers was bought forward one to two years earlier. In a period of rising prices, those forward purchases may be priced below market. Therefore, the blended price of utility supply may be less than the current price of an ARES or municipal aggregation offer. The IPA suggests this price difference may result in increased migration back to the utility. The reverse is also true: higher utility supply costs may increase switching away from the utilities.

The IPA believes these trends may be intensified if there is a lag in reflecting the utility's energy costs in customer rates. Slowly rising rates will increase switching to the utility, while slowly dropping rates may increase migration from the utility. The IPA states that volume changes resulting from these pricing differences may result in additional price risks.

According to the IPA, the standard on-peak and off-peak block energy products do not reflect each hour's load. These products provide a constant volume and hourly price across a fixed number of hours. Hourly energy prices vary across the day and within each of the peak and off-peak periods. Load also varies within those periods and a great deal of that variation is predictable. Energy costs more when demand is high and less when low. The IPA concludes that fixed volume and price purchases by themselves give an inaccurate forecast of the cost of energy to serve load and provide only a partial price hedge. Because of this variation, the IPA believes if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. The IPA says residual risk will still exist because the actual load is usually greater or less than the average.

The IPA says hedge contracts for energy located remotely from the load location have transmission access and congestion risks. The IPA claims this is unlikely to be a problem with hedge contracts that deliver to the LSE's load zone, as is the case with existing hedges for which the IPA has procured.

The IPA alleges that renewable energy procurement requirements met through the purchase of generation output are subject to intermittency. The IPA says the cost to cover this intermittency may not be hedgeable because the IPA procures renewable products (such as RECs or energy on an as-generated, rather than as pre-scheduled, basis) that are not comparable to standard block energy products.

Traditionally, the IPA says a utility's electricity supply plan includes physical supply and financial hedges. Physical supply includes the power plants that the utility owns or controls, as well as transactions for physical delivery of electricity, while financial hedges are additional hedging instruments used to manage residual price risk and other risks, such as weather risk.

The IPA notes that ComEd and Ameren divested their generating plants to unregulated affiliates or third parties. They have no contracts for unit-specific physical delivery, other than certain qualifying facilities ("QF") under the Public Utilities Regulatory Practices Act ("PURPA") contracts; their long-term renewables Power Purchase Agreements ("PPAs") are structured as "Contracts for Differences." The IPA says the utilities do not purchase and take title to electricity. The utilities' supply positions, other than RTO spot energy, are price hedges.

The IPA reports that physical electricity supply and load balancing for ComEd and Ameren are coordinated by the respective RTOs. ComEd and Ameren are considered Load Serving Entities by the RTOs. Each RTO provides day-ahead and real-time electricity "spot pricing." That is, generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. The IPA says the RTO ensures the physical delivery of power. The cost of managing this delivery, including the cost of managing reliability risks is passed on to the LSEs financially. The IPA asserts that the risks faced by LSEs in supplying energy to customers are mostly financial. The LSE still needs to manage certain operational risks such as scheduling and settlement. The IPA claims there are other, non-financial risks associated with electricity retailing, such as customer billing or accounts payable risks; but those are not associated with the supply portfolio.

Each RTO charges a uniform day-ahead price for all energy scheduled in a given hour and delivery zone. To the extent that real-time demand differs from the day-ahead schedule, the IPA says the load is balanced by the RTO at a real-time price; if demand exceeds the day-ahead schedule then the LSE pays the real-time price, and if demand is less than the day-ahead schedule the LSE is credited the real-time price. According to the IPA, both the day-ahead and the real-time prices are referred to as Locational Marginal Prices ("LMPs") because they depend on the delivery location or zone.

The IPA believes an important category of energy supply hedges is a unit-specific supply contract and says other supply hedges are forward contracts, futures contracts, and options. The IPA says unit-specific hedges are contracts for the output of a specific generator. Contractually they are sometimes structured as financially-settled swaps. The IPA indicates that the selling counterparty (i.e., generator) pays the hourly spot LMP to the buyer (i.e., LSE), and receives from the buyer either a fixed payment per megawatt-hour or a payment computed from a floating index (as in the case of a contract indexed to the price of fuel). The amount of the payment for each hour is the difference between these two $/MWh values and a notional energy quantity, which equals the volume of energy dispatched by a specific generating unit or a fixed fraction of the dispatched volume. The IPA states that unit-specific hedges may be categorized based on the control that the buyer has over the unit's dispatch.

- As-available. In this case, the IPA says the buyer cannot instruct the unit to generate, although in some cases the buyer has a limited right to curtail the generation. As-available hedges usually involve intermittent renewable generators that have an uncontrollable energy source, or which depend on the availability of energy as a byproduct of an economically independent industrial process (e.g., cogenerators that are QFs). In an as-available hedge the payment received by the generator is usually a fixed amount per MWh. The 20-year renewables contracts entered into by ComEd and Ameren in 2010 are examples of unit-specific, as-available energy hedges. The IPA says they are actually unit-specific as-available combinations of energy hedges and REC supply contracts.
- Baseload. In this case, the IPA says the generator is assumed to operate around the clock except for outages. There can be notice provisions or performance standards that are intended to limit the impact of forced outages and provide certainty around the timing of maintenance outages. The payment received by the generator may be a fixed amount per MWh or an amount indexed to a fuel price.

- Dispatchable. In a dispatchable contract, the IPA says the buyer has the right to schedule the generator's operation, except for outages. They are like options exercised each hour, subject to physical constraints on the unit's ability to modify its generation level. The payment received by a dispatchable generator will often be indexed to a fuel price, in which case the dispatchable contract is similar to a physical tolling contract. There is usually an initial cost to the buyer to enter into a dispatchable contract, equivalent to an option premium. As-available or baseload contracts often have no initial cost or option value.

The IPA states that other available hedges do not depend on the production of any generating unit or combination or units. From the standpoint of a generation owner, selling such a hedge it is "portfolio-based" rather than unit-specific because it depends on the owner's entire portfolio.

- Standard forward hedges. The IPA states that a forward contract for energy is a contract for the delivery of energy at a future date, or over a fixed period of time in the future, at a predetermined fixed price. A financial forward hedge is a fixed-for-floating swap where the selling counterparty receives a fixed payment for energy in each hour, and pays the RTO LMP to the buyer. A notional hourly energy volume multiplier is used to determine the payments. The period of time and the notional volume are defined in the contract. Standard wholesale forward contracts cover one or more months. A typical contract sold in the winter for summer delivery would cover July and August, or the third calendar quarter. While in May, one would be more likely to find separate contracts for the following July and August. A "7x24" contract has a constant notional amount in each hour. A "5x16 peak" contract has a constant notional amount in each hour from the hour ending ("HE") 7 AM to HE 10 PM (prevailing time) on weekdays except for holidays, and zero in other hours. An "off-peak" contract has a constant notional amount in the hours in which a peak contract has a zero notional amount.

- Shaped forward hedges. According to the IPA, a shaped forward hedge is similar to a standard forward hedge except that the notional volume can vary across the hours of the delivery period. For example, the notional volume could be proportional to the average expected customer load in each hour, to hedge against the correlation of price risk with load. Alternatively a shaped forward hedge could be based on a different time period. For example, there could be a fixed notional volume only in weekday afternoon hours, or on weekends and holidays from HE 7 AM to HE 10 PM but not other off-peak hours. Trading in shaped hedges is much less liquid than trading in standard forward hedges. The IPA suggests one could expect shaped hedges to be priced at a premium to expected LMP prices, or, at a higher premium than standard forwards.

- Futures contracts. The IPA says futures contracts are purely financial instruments that are not subject to delivery requirements such as day-ahead scheduling with the RTOs. They are otherwise similar to forward contracts except for collateral and margining requirements. Futures contracts generally require both parties to deposit cash with an exchange, and as the contract price moves each day this “margin” is moved between the parties’ accounts to reflect their gains and losses. In this way, futures contracts are settled incrementally up to the expiration date (end of the delivery period). Forward contracts are settled entirely on the expiration date, or monthly if the term is longer than one month. Instead of margin, forward hedges often require parties to post collateral with each other as a guarantee of settlement. Both the New York Mercantile Exchange ("NYMEX") and the Intercontinental Exchange (“ICE”) list futures contracts corresponding to the standard forward hedges described above, at both the PJM Northern Illinois Hub (ComEd) and the MISO Illinois Hub (Ameren).

- Options. The IPA indicates that a call option gives the buyer the right, but not the obligation, to buy a specific contract. A put option gives the buyer the right, but not the obligation, to sell a specific contract. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. A price decrease is a risk to the utilities, passed through to their customers, if it is accompanied by increases in municipal aggregation or other forms of switching that leave the utility expensive hedges it no longer needs. Options on forward or futures contracts are much less expensive than the contract themselves, because they only convey the right to spend the money to buy the contract.

- Swing options. The IPA states that a swing option is a forward hedge that gives the buyer the right, but not the obligation to change the volume in some subset of hours. Generally, the buyer can either zero out the volume in hours in which it was previously nonzero (curtail), or increase the volume from zero to the full notional volume (dispatch). A contract can include multiple “swings," that is, multiple points at which the decision can be made. A dispatchable option is essentially the same as a swing option with one swing each hour, and unit-contingent volumes. Swing option contracts are generally customized. An exception is a unit-specific dispatchable contract, which is a standard concept.

- Full requirements hedges. According to the IPA, a full-requirements or “tranche” contract covers a fixed fraction of an LSE’s load, rather than a fixed volume. For example, a 1% one-month tranche contract is a swap contract under which the selling counterparty receives an amount for each hour in the month equal to a fixed price per MWh multiplied by 1% of the LSE’s total supply requirement for that hour (load plus losses), and would pay to the LSE an amount equal to the LMP multiplied by 1% of the LSE’s

> total supply requirement for that hour. All these hourly amounts are netted for the entire month. One hundred such tranche contracts will fully hedge the LSE's energy supply for the month, at a fixed price.

The IPA asserts that full requirements hedge contracts differ significantly from the other examples. Forward hedges and futures require specification of the notional energy volumes. The IPA claims this makes them convenient for suppliers, who can, for example, sell a forward contract to achieve a precise effect on their portfolio. For example they can be used to take a short position, flatten the portfolio, reduce overall risk, etc. They are not as convenient for an LSE with a varying and uncertain load, who may wish to have a perfectly hedged portfolio. The IPA says forward block hedges cannot perfectly cover a load that is 1,900 MW in HE 10 AM and 2,900 MW in HE 4 PM. And, forward hedges cannot perfectly cover a load at HE 4PM that can be either 2,900 MW or 2,000 MW, depending on the weather. Full requirements hedges are useful in addressing load-related risks. The IPA also says full requirements hedges can also be used in combination with other standard products in a supply portfolio to reduce, but not completely eliminate, price risk.

According to the IPA, full requirements hedges have been used in other states to provide the utility its entire supply requirement at a known fixed price for a specific term. They are not traded products and had to be specifically defined (standardized) for the purpose, through regulatory processes. Auctions were defined in which the utilities would procure them. Information sharing and multiple workshops were needed to ensure that the auctions would attract significant supplier participation and produce competitive prices.

The IPA claims full requirements hedges can also be used to reduce, but not eliminate the load risk. For example, an LSE could buy thirty 1% tranche contracts, as well as a number of other standard products, to better but not fully hedge its supply requirement. The IPA says the cost premium of full requirements contracting can only be evaluated by comparison with the value of eliminating price risk (equivalently, eliminating the Purchased Electricity Adjustments).

In the IPA's view, not all of the types of hedges described are suitable for use in this procurement plan and all may not be readily available in electricity markets. The IPA says Illinois requires that "any procurement occurring in accordance with this plan shall be competitively bid through a request for proposals process," provides a set of requirements that process must satisfy, and mandates that the results be accepted by the Commission. Among the specific requirements, the procurement administrator must be able to create a market price benchmark for the process; the bidding must be competitive; and the procurement administrator is required to report on bidder behavior. The IPA believes the most natural evidence of competitiveness will be breadth of participation, although other evidence may be possible as well.

According to the IPA, hedges most suitable for its use would be those standardized products that are well-understood, and preferably widely traded. If a product has liquid trading markets, or is similar to other products with liquid markets, the IPA suggests a bidder can control its own risk exposure. Availability of information on current prices and the price history of similar products help bidders provide more competitive pricing, and help the procurement administrator produce a realistic benchmark. In its previous procurement plans the IPA has generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The IPA says its recommended plans have been stated in terms of monthly contracts although procurement events have met some of these needs with multi-month contracts.

The IPA states that in the past it has purchased energy products that are not typically traded, such as the long-term PPAs with new build renewable generation that were authorized in the 2010 Procurement Plan. The IPA notes these products still must be standardized in such a way that the winning bidders may be selected based on price alone, and the price is subject to a market-based benchmark. As a result, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could end up litigated in this proceeding. For any discussion about authority and policy regarding full requirements purchases, the IPA notes that the markets will likely not be as transparent, which in turn results in challenges for the benchmarking and approval process that are central to the IPA’s procurement structure.

The IPA claims futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub are traded in reasonably deep liquid markets, making such contracts easier to benchmark. The markets for long-dated (i.e., further in the future) contracts are less liquid. The IPA believes it should be able to obtain competitive pricing on such contracts if it were to want to incorporate them in its portfolio. However, the IPA believes it may be difficult or impossible to conduct the statutory RFP process for futures contracts; for example, it is unclear how the margin requirements would fit within the current regulatory framework.

Even if the utilities cannot procure futures contracts directly, the IPA says it does take them into account in the development of its procurement strategy. For example, in the past the IPA says it has procured forward contracts in 50 MW increments. NYMEX futures are 5 MW contracts. This means that both price discovery and supplier hedging are available for smaller quantities. The IPA believes it should be able to conduct its procurements in smaller units, such as 25 MW blocks.

The IPA maintains that Ameren will be overhedged and will have forward contracts in excess of expected load for most or all of the 2014-2015 delivery year and ComEd appears not to be overhedged in 2014-2015, but under a low load growth, high switching scenario will be overhedged later in the projection horizon. Furthermore, the IPA says if it continues to use a “laddering approach,” it is quite possible that in future years one or both utilities will find that it over-procured in the early years of the ladder and became overhedged.

The Illinois Power Agency Act ("IPA Act") specifies that the procurement plan “shall include . . . the criteria for portfolio re-balancing in the event of significant shifts in load." The IPA believes such re-balancing may be necessary this year, in the case of Ameren. It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the IPA, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

To date, the IPA claims the only rebalancing of hedge portfolios prior to the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a mandated rate cap. Since these contracts provide renewable energy (energy plus RECs), curtailing them has reduced ComEd's forward position. In the IPA's view, this is a small effect compared to the potential re-balancing need, especially for Ameren. Ameren has not curtailed renewable contracts.

The IPA asserts that for the last few years the utilities have rebalanced their portfolios in the RTOs' day-ahead markets. This has been the dominant mode of portfolio rebalancing. Revenues from the sale of excess energy in the day-ahead market helps to offset the overall cost of the hedges already procured.

As an alternative form of rebalancing, the IPA suggests it could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The IPA says it would have to verify that these kind of events fall within its authority to "conduct competitive procurement processes" under Section 1-20(a)(2) of the IPA Act and that the utilities whose contracts are to be sold or who would be selling an offsetting position are amenable. The IPA believes the utilities' amenability will probably flow from Commission approval of a procurement plan including such reverse RFPs. Finally, the IPA says the risk associated with the volume to be re-balanced would have to be large enough to justify the expense of a procurement event.

The IPA claims it could also conduct an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. The IPA suggests this may avoid contractual difficulties associated with selling forward hedge contracts, if those contracts are not freely assignable. However, this approach will require the utilities to ensure they had regulatory approval to exercise the options after purchasing them.

D. 2014 Procurement Plan Resource Choices

The primary resources included in the 2014 Procurement Plan for the forecast horizon include: (1) incremental energy efficiency; (2) energy procurement strategy; (3) balancing market recommendations; and (4) demand response. The Procurement of additional Renewable Resources, including wind, solar and distributed generation, is considered separately.

1. Energy Efficiency

The IPA indicates that the 2013 procurement plan was the first plan to include consideration of incremental energy efficiency programs pursuant to Section 16-111.5B of the PUA. That plan included the approval of eight expanded or new programs each for Ameren and ComEd. These programs started implementation on June 1, 2013, and no results or impacts of those programs are yet available.

If Ameren's approved programs from the 2013 plan result in savings in a manner consistent with Ameren's assessment and the Commission's final approval, the IPA says the Ameren programs are expected to provide incremental net energy savings of 70,834 MWh for the June 2013-May 2014 program year. After considering the impacts of projected customer switching, the anticipated reduction to the energy required for the IPA-procured portfolio is 25,409 MWh for the June 2013-May 2014 delivery year. Ameren further estimated that these programs would reduce demand during peak periods by no more than 4 MW. ComEd's Commission-approved programs are estimated to provide an annualized savings goal of 173,753 MWh to the total population of retail customers to which they are being offered. The annual savings estimates for ComEd customers served by the IPA-procured portfolio range from 22,574 MWh for the 2013-14 delivery year to 39,688 MWh for 2014-15. ComEd further estimated that these programs would reduce demand during peak periods by no more than 6 MW. The IPA notes that each of these savings targets is based on a maximum spending level for the utilities' implementer contracts; the utilities are under no obligation to deliver the exact expected MWh or MW savings.

In its approval of the IPA's 2013 procurement plan the Commission ordered workshops to be conducted by Commission Staff to consider the coordination between the incremental energy efficiency programs included in the IPA procurement plan and the programs run under Section 8-103 of the PUA, commonly known as the Energy Efficiency Portfolio Standard ("EEPS").

The IPA reports that Commission Staff held a series of workshops that met multiple times during the spring of 2013. The IPA says it and many other stakeholders actively participated. A Staff Report was issued on August 2, 2013, which provides a high-level view of the topics discussed and ideas shared during the workshops. The IPA states that the workshop process, while helpful, did not result in a formal agreement and therefore may not represent the formal opinions of participating parties. Further, the parties sought to, and at times did, reach consensus based on then-current, prevailing information and policy at that time of the discussions. Parties' positions were therefore subject to change based on changes in information and policy. The IPA thus regards the Staff Report as a useful reference point for its discussion, but not a binding document.

The IPA indicates that it appreciates all of the efforts that Commission Staff and other stakeholders put into these workshops. The IPA says topics were extensively discussed and consensus was reached on many items. Although parties generally valued coordination between energy efficiency programs, the “EEPS programs” or “8-103 programs” (i.e. programs authorized by Section 8-103 of the PUA) have several differences from the Section 16-111.5B energy efficiency programs run through the IPA procurement plan, not the least of which is statutory penalties directed at utilities for failing to reach savings goals for EEPS programs. As a result, the IPA says many of the discussion items have greater impact on the EEPS programs than on the Section 16-111.5B programs. The IPA states that other issues, such as verification or “net to gross,” certainly play roles in Section 16-111.5B programs, but not necessarily in the front-end approval process to be carried out in this docket. The IPA recognizes that there may be other dockets, especially those to approve Section 8-103 plans, which may be more appropriate venues for the Commission.

To the extent possible, it appears to the IPA that the utilities incorporated consensus of the workshop participants into the development of submittals, and the IPA also has sought to reflect its understanding as the consensus from the workshop in its review of the submittals and the development of this plan. However, the IPA says that in some cases the consensus achieved was useful to frame open issues, but the IPA has in its review now identified more detailed issues and related solutions for further consideration among the stakeholders. The IPA requests that the Commission make determinations on these more detailed issues.

The IPA states that while the workshops addressed many important issues, there are a number of questions that were not fully resolved or discussed completely. The IPA claims these questions may directly impact the 2014 Procurement Plan and could be addressed in the approval of this Procurement Plan. The IPA requests that the Commission consider these issues and to the extent possible, make determinations that will guide this and future procurement plans.

The first issue of concern to the IPA is the lack of an adequate feedback loop in the development of programs for consideration for inclusion in the procurement plan to ensure the statutory goal of “fully capturing” the potential for all achievable cost-effective savings, to the extent “practicable.” By “feedback loop," the IPA means a process or processes that ensures that energy efficiency opportunities identified in the utility’s required potential study that are not met by the third-party RFP process are somehow filled. The IPA says that while several workshop consensus items address what the utilities should include in their submittals to the IPA pursuant to Section 16-111.5B(a)(3), the consensus items may not adequately address this issue. The IPA claims the programmatic planning link between the potential studies and the programs submitted to the IPA is not explicitly spelled out in the statute. The challenge the IPA wishes to address is how to ensure that the statutory goal of “all achievable cost-effective savings” is captured through the process dictated by Section 16-111.5B. The IPA is concerned that the combination of the new programs and expanded utility programs (that each has a TRC of greater than one) may not fully meet the outer boundaries of the potential study in any given year.

The IPA believes that the potential studies could provide a roadmap for what is economically achievable, but if the third-party bids and/or the expansion of existing programs does not fill all the gaps identified in the potential study, there is no mechanism to do further solicitation for programs, or in-house program development. The IPA believes this problem is further exacerbated in years where the EEPS programs are up for review for a new three year cycle and therefore there are not Commission-approved EEPS programs to "expand." The IPA says the Procurement Plan this year faces exactly that challenge. With the filing date for approval of the new EEPS programs coming a month prior to the filing date of this Plan (and Commission approval likely after the statutory deadline in the Procurement Plan approval docket), the IPA is unable to determine if there will be approved EEPS programs that meet the opportunities identified in the potential studies that are not otherwise met by the programs submitted to the IPA by the utilities under Section 16-111.5B.

To mitigate this issue, the IPA suggested that in the consideration of this year's draft Plan for comments, the stakeholders recommend changes to the third-party bidding process to allow for more flexibility in the bidding procedure to help identify more programs that are technically and economically "feasible," "cost effective," and "practicable" as required by statute. The IPA reports that in the comments received on the draft plan, several parties pointed out that the additional feedback mechanisms may just lengthen an already very long process between RFP responses and program implementation. The IPA does not recommend supplemental RFPs to be held to "fill in" categories of the potential study that are not filled by third-party bidders. There were also suggestions on how to clarify the third-party bid RFPs and to give vendors opportunities to adjust their proposals.

In the IPA's view, NRDC raised an interesting point that the third-party bids tended to be focused on retrofit programs rather than programs that would influence the purchase of efficient products. The IPA does not have a position at this time as to whether this trend overall is good or bad, but this issue may be worthy of future examination, including the impact on reaching the limits of the potential study for purchase of efficient products. If the Commission (or the IPA at a future date) believes this is problematic, the IPA believes two questions are important to answer: First, are there structural limitations to the Section 16-111.5B process that lead to this outcome? Second, if there are structural limitations, is this inherently a problem or do the opportunities created by Section 8-103 or utility-run programs adequately address them?

The IPA recommends that the Commission consider stakeholder input on this issue and provide clarity to the utilities for next year's RFPs, if possible. The IPA says this issue may not be possible to properly resolve absent legislative changes to Section 16-111.5B of the PUA. In the interim, the IPA believes that any direction the Commission can provide on this issue will aid bidders and the utilities to provide a set of achievable cost effective energy efficiency programs to the Commission which will allow the Commission to make the necessary statutory findings pursuant to Section 16-111.5B(a)(5) of the PUA.

A second issue of concern to the IPA is the uncertainty regarding this transition year where the EEPS programs for next year are not yet approved. In years where EEPS programs are already approved, the IPA says the consideration of expansion of those programs can follow a logical path, but that path is not available this year. A consensus item from the workshops was that Section 8-103 and Section 16-111.5B filings could have their timelines aligned. The IPA states that while this would be helpful on some level because the stakeholders in the IPA plan approval process would know what programs are under consideration in the Section 8-103 proceeding, it will not fully address the issue that those programs are not actually approved by the time the Commission must approve the IPA's procurement plan. In their submissions to the IPA for this procurement plan, the IPA says the utilities have addressed the expansion issue by seeking approval for some programs through Section 16-111.5B and others pursuant to Section 8-103 (rather than expanding existing programs previously approved pursuant to Section 8-103). In anticipation of the this triennial issue, the IPA believes a legislative change to either Section 16-111.5B or 8-103 of the PUA would likely be necessary to create a mechanism for utilities to seek expansion of Section 8-103 programs through the Section 16-111.5B process, rather than seeking approval for new programs only when an 8-103 three year plan is awaiting Commission approval.

The third issue of concern to the IPA is how the Department of Commerce and Economic Opportunity ("DCEO") can participate in the Section 16-111.5B process. There was consensus in the workshops that DCEO should participate in the Section 16-111.5B process, and DCEO programs that have a TRC exceeding one should have a mechanism for inclusion in the Section 16-111.5B procurement, perhaps via the RFP process although the exact procedure was not fully discussed. The IPA says the workshop did not fully resolve significant details, such as how DCEO should, or may, participate. Because the utility energy efficiency RFP process for this procurement planning cycle has already passed, to the extent DCEO participation in the utilities' RFP process is feasible, the IPA claims it is not available for this Procurement Plan. The IPA also understands that DCEO may have some administrative limitations regarding contracting that could preclude that option in future years; the IPA hopes that DCEO will provide additional details on this matter in objections.

DCEO provided to the IPA on July 15, 2013 a proposed filing under Section 16-111.5B that included incremental energy efficiency programs that DCEO stated pass the Total Resource Cost Test. The IPA determined that it could not include the programs proposed by DCEO pursuant to Section 16-111.5B at this time because DCEO is not a utility as the term is used in Sections 16-111.5 and 16-111.5B. The IPA recognizes that the programs proposed by DCEO have great potential value (the TRCs of both programs easily exceeded one), especially to low income customers, but the IPA says it is restricted to the parameters of statutory and Commission authorization in its ability to include the DCEO filing in its submittal of the procurement plan to the Commission. In light of the limitations of Section 16-111.5B, the IPA requested additional proposals for creating a mechanism for their inclusion in the 2014 procurement plan. To facilitate concrete discussions, and perhaps Commission approval, the IPA is placing DCEO's submission in the record of this docket, as

Appendix H to its filed plan. It appears to the IPA that of the two programs in this year and prospectively included in future years, the proposal, one (street lighting enhancement) would be a new program, while the other (Energy Savers) is an expansion of a program that DCEO has now included in its August 30, 2013 Section 8-103 filing before the Commission.

The IPA hopes that the discussion of this issue will help provide a template for a process for use in future years that could result in upfront coordination between DCEO and the utilities that would allow for DCEO programs to be included. The IPA further notes that it will follow any Commission Order interpreting Section 16-111.5B to require inclusion of DCEO programs in this year and prospectively in future years.

The final issue of concern to the IPA is competition between incumbent utility programs and third-party RFP programs. The IPA says at a high level there are two issues. The first issue is what it means for a third-party bidder's proposed program to be "competing" with or be "duplicative" of a utility program. The IPA claims that although it may be obvious in some cases (such as with Ameren's SAIC Small Business Direct Install program) where a third-party bidder is seeking to serve the exact same market with similar or the same energy efficiency solution, the IPA is not aware of a Commission-approved standard for these terms in the context of Section 16-111.5B. Based on the comments received on the draft plan, the IPA proposes to use the term "duplicative" to mean a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers. The nature of the energy efficiency market is that in many cases efficiency is derived from single distribution channels. The IPA says that in the same way that having many supplier options (from bundled rate to residential real-time pricing to retail service) benefits consumers by offering a variety of energy services, there could be energy efficiency offerings that would benefit from multiple channels. While there do not appear to the IPA to be such programs in this year's submittals, the IPA suggests using the term "competing" for such programs if they are proposed in future years. The general goal would be that duplicative programs are to be avoided, but that competing programs would be acceptable to the extent that the competition does not render one or both non-cost effective.

The second issue is the authority of the Commission to reject a third-party bidder's program that is "competing" with or "duplicative" of a utility's program but which otherwise passes the standard for cost-effectiveness. Section 16-111.5B does not directly address this matter, although it is possible to read the statutory terms "new," "expanded," and "incremental" as requiring new programs that are additive (i.e. non-competitive and non-duplicative) to utility programs. The IPA believes the Commission may wish to clarify if the utilities may screen out those programs pursuant to Section 16-111.5B(a)(3) or whether the IPA must include all "competing" or "duplicative" programs and then request that the Commission remove those programs pursuant to Section 16-111.5B(a)(5).

The IPA sought comments on these issues and after reviewing those comments, the IPA recommends continuing the process followed this year that does not set a specific standard. In this process each utility would continue to provide to the IPA all third-party bids received, and further the utility would provide an initial recommendation regarding any screening out of programs that the utility deems to be duplicative. The IPA would then include in its filing to the Commission its assessment of all bids received and its assessment of the screening (if any) done by the utility. The IPA says the Commission would then provide the final determination as to which programs are included based on any objections received that would change the Commission's understanding of if the program in question is or is not duplicative or competing.

The IPA states that in general stakeholders felt that it was important for the Commission to have the opportunity to review information regarding all bids, and also that the utilities be given some level of discretion (although stakeholders did not agree on just how much) in judging which programs to include and which ones were duplicative and did not add value. The IPA recognizes that the marketplace for energy efficiency is dynamic and that TRC calculations are generally done in isolation (i.e. imagining that each program is not competing with the same or similar programs for market share). Including duplicative or competing programs could impact the accuracy of the TRC test.

If the Commission chooses to adopt a standard for duplicative or competing programs, the IPA suggests that the standard be a multi-factor inquiry rather than a "bright line" test. Factors that the IPA suggests that the Commission consider to be part of the standard include (but are not limited to): (1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); and (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record). The IPA invites parties in objections to recommend additional criteria or modify the criteria it suggested.

The IPA notes that in reviewing the RFPs issued by the utilities they do contain guidance to potential bidders regarding not proposing duplicative programs. Some stakeholders believe that this language may have been unclear or confusing. The IPA suggests that for future RFPs the utilities work with stakeholders to refine that language to make it clearer to potential bidders.

According to the IPA, Ameren's proposal contains programs and measures that were "expanded" from the Section 8-103 by virtue of being removed from Ameren's Section 8-103 three year plan filing and moved to and expanded in its IPA submission. Examples include moving specialty lighting, electric home improvements, small business incentives and multifamily common area measures out of its Section 8-103 portfolio and into the IPA submission at higher than previous levels.

The IPA reports that in its submittal, Ameren also stated that:

> This submission represents one year of savings and costs. However, AIC reserves the right to submit multiple years of programs and related savings in future submissions.

According to the IPA, one impact of this approach is that the MWh goal of the submittal is smaller than that of the previous year, in part for the simple reason that it includes only stand alone programs rather than last year's the expansion of programs authorized pursuant to Section 8-103. The lack of Section 8-103 programs to expand illustrates the open issue about years in which a three-year energy efficiency plan is under consideration. The IPA says Ameren's assessment includes five energy efficiency offerings in this Procurement Plan and all of these programs passed the TRC test at the time of assessment.

A table showing Ameren's programs was provided by the IPA and is reproduced below.

Ameren Energy Efficiency Offerings

Program	Net Savings (MWh)	Total Utility Cost	TRC
Multifamily	14,247	$4,292,956	2.95
Specialty Lighting	5,970	$2,794,093	1.12
Rural Efficiency Kits	3,555	$377,365	3.28
All-Electric Homes	11,189	$7,039,702	1.49
Small Business Direct Install	30,719	$8,715,840	1.14

The IPA says the total net savings for these programs is estimated as 65,680 MWh at the busbar. The programs also contribute to a peak reduction of approximately 2 MW. The estimated savings attributable to eligible retail customers is 17,950 MWh. The IPA believes that subject to the modifications and open issues, Ameren's submission meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix B to the 2014 Procurement Plan should be approved pursuant to Section 16-111.5B(a)(5) of the PUA.

In addition to its own programs ("Ameren programs"), the IPA says Ameren assessed six additional programs from third-party vendors ("Bidder programs"). Three Bidder programs did not pass the TRC; one program was determined by Ameren to be duplicative of the SAIC Small Business Direct Install program, one program was excluded because it was designed as a gas and electric savings program that assumed participation by a separate gas utility that could not be assumed, and another program was the expansion of the SAIC Small Business Direct Install program.

The IPA has reviewed the Bidder program that Ameren considered duplicative of SAIC Small Business Direct Install program and it illustrates the challenges of the "competing" and "duplicative" issue. The Bidder program would specifically target class B and C commercial office spaces, which is a smaller market subset of the SAIC Small Business Direct Install program. Class B and C office spaces are already served by Ameren's program, (but not specifically targeted), so failure to include the Bidder program would not hinder the statutory mandate to expand cost effective energy efficiency programs. On the other hand, the IPA believes there could be value in testing alternative delivery mechanisms for this specific sector if, in fact, the Bidder program is superior, although there is not sufficient information in the submittal to determine that). Absent any determination that this program in fact is not duplicative (albeit more targeted) of what Ameren will already offer in the SAIC Small Business Direct Install program, the IPA recommends that the Commission not approve the inclusion of this program as its inclusion may not be "practicable."

Ameren also proposed excluding a Bidder program that would deliver education kits to students via the classroom. Ameren stated that it did not include the program because it is a gas and electric savings program and Section 16-111.5B specifies that the IPA energy efficiency programs be provided and coordinated by the electric utilities for the purposes of electric savings. Ameren further noted that the program targeted an area where Ameren was not the gas utility, that the gas utility in question (Nicor Gas) is not a participant in this procurement process and that their participation cannot be ensured or required. In comments Ameren further stated that they did not evaluate or validate this vendor in terms of its ability to actually deliver the program, its reputation, credit worthiness or references once it was determined that the program was not applicable to this procurement process. Therefore, in the event the program is conditionally approved, the program's inclusion should also be subject to Ameren's evaluation and validation of the vendor.

The IPA says Ameren's August 31, 2013 Section 8-103 filing (which, unlike Section 16-111.5B, addresses both gas and electric energy efficiency because Ameren is a combination utility) included a proposed student energy kit program by a different vendor and at a substantially larger scale. While the IPA has not conducted a thorough comparison of the details of the two programs, the presence of that proposed program suggests that this market sector may be well served. Notwithstanding the contractual issues identified, assuming that the Section 8-103 program is approved by the Commission, the IPA does not recommend the inclusion of the student energy kit program under Section 16-111.5B.

Ameren included in its submission a base program for small business direct install. It also included in its assessment the bid for an expanded version of the program (73,435 MWh versus 30,719 MWh) but recommended the base level – a continuation of the same size program from the previous year, which began implementation in June 2013, – because in Ameren's view it is, "prudent and responsible to first assess and evaluate the performance of this program prior implementing it again on a larger scale." The IPA appreciates the program management and evaluation issue that Ameren raises, but notes that programs implemented under Section 16-111.5B do not have penalties for non-performance. In comments, Ameren also raised the issue of risks associated with the Commission reconciliation review, which examines Ameren's management of the program. The IPA understands and appreciates that utilities are always subject to the review of certain management and performance standards by the Commission, and that placing unrealistic expectations on any utility program could theoretically force imprudent steps that could jeopardize cost recovery. However, the IPA would like to see more discussion from Ameren as to why an expansion of the program to a level first raised by Ameren, or its vendor, would lead to that result.

Ameren also requested in its filing that the Commission make several determinations:

- "[I]t is realistic to assume that actual market results will differ from anticipated results. Therefore AIC formally requests approval for an indeterminate fluctuation in savings that may occur by program year end."
- Ameren, "seeks confirmation that AIC is permitted to recover costs that incidentally (3 - 5%) exceed the estimated program costs as consistent with the Commission finding in the ComEd energy efficiency 'Plan 2' plan docket #10-0570." The IPA says this was a consensus item from the workshop. Ameren further notes that, "In lieu of this express approval AIC will be forced to prematurely discontinue approved programs prior to the budget cap being expended."
- "AIC notes that the savings estimates were determined using the current Illinois Technical Reference Manual ("TRM") and Net-to-Gross ("NTG") values and unless these values are fixed, they are subject to change. With this submission, AIC is formally requesting that these values are fixed for implementation and evaluation for the determination of achieved savings."

The IPA does not object to any of these requests as it believes they appear to be consistent with consensus items from the workshops. Besides these determinations, the IPA requests that the Commission, at minimum, approve the incremental energy efficiency programs proposed by Ameren and that the Commission further consider the additional recommendations of the IPA.

ComEd's assessment includes eight energy efficiency offerings in this Procurement Plan. All of these programs passed the TRC test at the time of assessment. These programs are exhibited in the table reproduced below.

Program	Net Savings (MWh)			Three Year Program Cost	TRC
	Year 1	Year 2	Year 3		
Home Energy Reports	301,780	374,971	390,233	$41,552,668	1.90
Small Business Energy Services	111,020	147,657	185,403	$110,013,985	2.32
CUB Energy Saver	6,628	13,256	19,884	$1,775,000	1.72

Home Energy Services	2,239	2,239	2,239	$4,701,285	1.23
Small Commercial Power Strip	4,840	-	-	$1,267,000	1.05
Energy Stewards	1,366	-	-	$200,000	1.97
Small Commercial HCAC Tune-up	3,690	10,335	12,170	$6,841,506	1.78
Retrofit Chicago Residential	1,285	1,685	2,029	$1,667,667	1.18

ComEd proposed both multi-year and single-year programs. The net savings at the busbar are 432,848 MWh for the first program year, 550,143 MWh in the second program year and 611,958 MWh in the third program year. These programs will deliver 16 MW of reduction in peak procurement for the 2014-2015 program year. The savings attributable to eligible retail customers is 88,839 MWh in the first program year, 137,288 MWh in second program year, and 184,078 MWh in the third program year. The IPA believes that subject to the proposed modifications and resolution of the open issues ComEd's, filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C to the 2014 Plan should be approved pursuant to Section 16-111.5B(a)(5).

As with Ameren, ComEd's proposal contains programs that it determined fit best in the Section 16-111.5B model but which had previously been part of EEPS. For ComEd, these programs are the Home Energy Report and the Small Business Energy Services. As with Ameren, these programs are included at scales larger than had been implemented under EEPS and are therefore considered program expansions.

ComEd evaluated 17 third-party bids. Of the eleven Bidder programs that were not included, one program was withdrawn by the bidder, three programs were determined to be incomplete or unresponsive, one did not pass the TRC, and six were deemed by ComEd to be duplicative of other proposals that ComEd considered. Of the six Bidder programs that ComEd considered duplicative, one was duplicative of ComEd's current multifamily program, two were duplicative of other current ComEd energy efficiency programs, and three were duplicative of the Small Business Energy Services that ComEd is including in its Section 16-111.5B proposal. The duplicative multifamily program also failed the TRC test.

The IPA maintains that the Commission has not provided a standard pursuant to Section 16-111.5B for evaluating "competing" or "duplicative," and has not provided direction about how to deal with "competing" or "duplicative" programs. The IPA therefore provides a discussion and recommendations on how to address each specific program.

For the two Bidder programs that compete with existing ComEd Section 8-103 programs, the IPA notes that ComEd describes them as "substantially identical" to the existing programs. However, the IPA says the ComEd Commission-approved programs are part of the Section 8-103 3-year plan portfolio that is ending this year and will be up for renewal concurrently with the Procurement Plan approval docket. The IPA states that ComEd has subsequently proposed programs in its August 31, 2013 Section 8-103 filing, which in substance appear to continue those existing programs. The IPA recognizes that there is a risk of the programs approved in the Section 8-103 proceeding, and also that Section 8-103 programs are subject to savings goals that lead to penalties if not met. As a compromise approach, the IPA recommends that the Commission consider conditional approval of the two programs. If the Commission subsequently does not approve the competing programs, then these programs (B9 and/or B10) should proceed. On the other hand, if the Section 8-103 plan programs are approved by the Commission then this conditional approval should be rescinded. Because it appears that these programs have been put forward for approval in ComEd's Section 8-103 proceeding, the IPA recommends that this conditional approval should not be reflected in the load forecast included in this Plan. By the time of the proposed March load forecast update, the IPA believes this issue should be resolved and the load forecasts could be updated as needed.

According to the IPA, a different issue arises for the three Bidder programs that ComEd excluded that are duplicative of the Small Business Energy Services program that ComEd included in its Section 16-111.5B filing. The IPA says one of the Bidder programs appears to have a scope as wide as the Small Business Energy Services Program in terms of customers, but has a significant geographical limitation. The IPA does not see a compelling reason to include this program and defers to ComEd’s determination to include its core Small Business Energy Services program to serve that sector. The IPA says the other two programs appear to target specific business sectors and as suggested with the similar Ameren submittal, the Commission may only want to consider including them if it is determined that they are not truly duplicative.

ComEd has requested that, “[t]o the extent that the IPA and the ICC approve procurement of the programs ComEd requests that the approval be for all three years.” In light of the consensus item that multi-year programs should be approved through the Section 16-111.5B process and because the programs’ TRC calculations are greater than one for a multi-year timeframe. The IPA agrees with that request.

Besides this determination, the IPA requests that the Commission at minimum approve the incremental energy efficiency programs proposed by ComEd and that the Commission further considers the additional recommendations of the IPA.

The IPA requested feedback from stakeholders on the concept of using energy efficiency as a supply resource that could reduce the need for procurement. The most detailed feedback received was that submitted by CUB. CUB proposed several possible program structures including ones to address high load hours, high price hours and peak hours. The IPA appreciates these suggestions and is most intrigued by the high load model. While the other two may have significant potential value to consumers, the high load model would appear to be the model that would most likely fit into the procurement processes that the IPA can, and does, conduct. The model also appears to be similar to an existing program in ISO New England that could provide a starting point for consideration.

ComEd and Ameren recommended removal of this section from the plan because it did not propose a specific procurement for 2014. The IPA agrees that because it is not proposing such a procurement in the 2014 Procurement Plan, the IPA will not add additional specifics at this time. Instead, the IPA proposes to conduct workshops and receive stakeholder input in early 2014 to further explore this model for the possible inclusion of a more specific proposal in future procurement plans.

The AG, NRDC, and the Sierra Club all commented on the underlying discussion, including the contention that the current Section 16-111.5B process does not sufficiently incentivize peak load reduction. The IPA appreciates these comments, and will take these comments into account in developing a proposal for the workshop process.

2. Procurement Strategy

In the IPA's view, the selection of the procurement strategy is driven by the following challenges:

- Price hedging: the IPA should find the best compromise between hedging against adverse price movements and retaining the flexibility to respond to rapidly changing market conditions.

- Load hedging: the accuracy of load forecasts increases as time to delivery decreases, particularly with regard to switching risk. For instance, load forecasts for the delivery year 2014-2015 that the utilities will submit in March 2014 should be more accurate than the forecasts for that year submitted in July 2013. Therefore, the IPA should ensure it has the opportunity to adjust its supply strategy to account for changes in load forecasts.

- Control of overhead cost: RFPs for energy contracts are costly and the IPA should take this into account in its procurement strategy.

In order to address these challenges, the IPA's procurement strategy has historically been designed in a “laddered” fashion: a large fraction of the load would be purchased for the prompt (upcoming) delivery year while smaller fractions of the load would be purchased for the subsequent two years. Prior to the 2013 Procurement Plan, the IPA procurement strategy for energy products was designed to result in a ladder of products predicated on being 100% hedged for the prompt year, 70% hedged for the second year, and 35% hedged for the third year.

According to the IPA, the laddered strategy is used to mitigate price risk, smooth out price spikes, and minimize exposure to any single set of forward prices. Due to accelerated customer switching, and, to a lesser extent, declining market prices, the IPA considered a revised strategy in the 2013 Procurement Plan in that, 75% of the load would be hedged for the prompt year, 50% for the second year, and 25% for the third year. By reducing the total hedge, the IPA indicates the utilities partly reduced their exposure to load loss, while the generally stable or declining market price environment reduced the penalty for underhedging. Ultimately, the IPA recommended this revised strategy be deferred until future Plans.

The IPA states that its analyses indicate that, while hedging could reduce the impact of forward price uncertainty it could not counter the effect of load uncertainty, a somewhat more significant impact. The IPA believes the following are conclusions relevant to procurement strategy that may be drawn:

- Load reduction is a particularly significant risk because losses associated with currently out-of-market hedges will have to be spread over a smaller pool of kilowatt-hours ("kWh"). The utilities' load forecasts did not assess the probabilities of their high and low load scenarios. Ameren's high and low scenarios each had the same weight in the Monte Carlo model and ComEd's high and low scenarios each had the same weight (although it was different from the weight on each of the Ameren high and low scenarios). Given the high current levels of municipal aggregation, it seems more likely that there will be a "rebound" effect reversing switching in the coming years.

- Switching decisions, especially having to do with municipal aggregation, have effects lasting two to three years. This distinguishes switching-related load variation from price variations, which decay much more quickly. It makes sense to delay forward purchases to the extent that they create load risk. The uncertainty in load forecasts should be reassessed each year. For example, in previous years a 100%/70%/35% procurement strategy seemed reasonable. In 2013 it was considered that the potential for load reduction made that strategy too risky and that forward purchases should be delayed with a 75%/50%/25% strategy. However, no formal request was made of the Commission in this regard given that no procurements were required in that plan.

- On the other hand, if the volume of load that could return to utility service is now greater than the risk of additional switching away, and if upside price risk is greater than downside risk, then the situation of the last couple of years could reverse and it would make more sense to be fully hedged close to the delivery month. In fact, the impact of shaping can be mitigated by hedging at about 106% of average load, June through October and 100% of average load November through May, so that "fully hedged" should be interpreted as 106% of average load June through October and 100% of average load November through May. Being fully hedged close to the delivery month will also help to reduce the volatility of Purchased Electricity Adjustment ("PEA").

- Forward contracts do not necessarily provide perfect hedges against load uncertainty; however, other products, such as full requirements hedges, are available in the market at premium prices.

3. Standard Market Products; Hedging

The IPA recommends that the basic strategy discussed in the 2013 Procurement Plan be slightly modified. The IPA says the procurement goal for a mid-April 2014 procurement event is to hedge 106% of the expected load forecast for June-October 2014 and 75% for November 2014 to May 2015. The IPA recommends that the utilities update their load forecasts in March 2014 subject to the consensus of the utilities, the IPA, Commission Staff, Procurement Administrator(s) and Monitor. the IPA also recommends that the recommendations in Tables 7-4 through 7-11 of the 2014 Plan be recomputed and further include any Commission-approved energy efficiency programs as well as the impact of any partial curtailment of long-term renewable contracts.

In the IPA's view, the March 2014 forecasts should include the effect of approved energy efficiency programs and provide the expected case as well as the high and low scenarios. Absent any large reduction in the Required Purchase Amounts, the IPA believes a procurement event should be held in April, 2014 for each utility to acquire contracts: for Ameren in the Required Purchase Amounts of Table 7-4, Table 7-6, and Table 7-7 of the 2014 Plan, and for ComEd in the Required Purchase Amounts of Table 7-8, Table 7-10, and Table 7-11 of the 2014 Plan.

The IPA also seeks approval to conduct a procurement event in September 2014 to bring the hedge levels to 100% for the period of November 2014 to May 2015. The IPA also recommends that, after taking into account the utilities' July 2014 forecasts, which the IPA recommends be expanded to include the November 2014 to May 2015 period, it be given the authority, in consultation with Commission Staff, ComEd, the procurement administrator, and the procurement monitor, to forego the September procurement if consensus is reached that the procurement would not be cost effective. Factors that the IPA proposes to consider in making such a determination would include whether the utilities' forecasted loads drop significantly, the risk associated with keeping the open position compared to the cost of running the auction, and the scale of the supplier fees required to recover the cost of the procurement. (This forecast for the November 2014 to May 2015 period, produced by the utilities in July 2014, will have no impact on the partial curtailment of long-term renewable contracts which would have occurred prior to the 2014-2015 plan year and will be based on March 2014 forecast). The IPA says the second procurement should be scheduled such that the Commission has time to approve any new procurement no later than September 22, 2014, in order to allow for prices for the non-summer period to be reset before the period begins.

Summary of Proposed Hedging Strategy

Mid-April 2014 Procurement			Mid-Sept. 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**	**November 2014-May 2015**
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

If there is a rebound effect from municipal aggregation, the IPA asserts that the utilities may actually experience a switch of the load back to them in the near future upon contract expiration. Because of this uncertainty, the IPA believes a bifurcated (April/September), fully hedged strategy in the 2014-2015 delivery year is a prudent option.

For the 2014 Procurement Plan, the IPA recommends purchases of standard forward block hedges in multiples of 25 MW, as opposed to 50 MW as in the previous plan, for the following reasons:

- The smaller individual increment provides a greater ability to accurately match load (25 MW increments vs. 50 MW increments), and therefore limits reliance on the spot market as a balancing mechanism during hours of imbalanced supply.

- Liquidity appears adequate, given that index publishers such as Platt's survey transactions down to 25 MW.

- They are standardized products with published definitions.

- Suppliers can hedge their own exposure in futures and/or forward markets.

The IPA notes that it considered other products that provide hedges against load uncertainty, namely full requirements products and options. The IPA says its analysis indicates that full requirements products do not have a great cost or risk advantage over a block-based strategy. The IPA says its analysis depends on a theoretical or conceptual model of how suppliers would price full requirements products. The IPA notes that prices may be less than the model implies, but on the other hand they may be much greater given the current load uncertainty.

The IPA indicates it is not prepared to recommend the use of full requirements products. The IPA is not aware of any recent assessments of the risk tolerance of retail customers; that is, their willingness to pay the utility for price insurance. Customers can easily switch to a competitive supplier and take fixed price service if they perceive value of mitigating price risk.

The IPA, in the preparation of the 2014 Procurement Plan, also considered a pilot program, involving only a fraction of the utilities' load, but decided that the overhead cost of designing a price benchmark and a procurement mechanism for such a different product is not justified given that hedging using standard block products represent a less expensive alternative. The IPA says a successful pilot program must also provide meaningful results that can be assessed and provide input into future decisions. It was not clear to the IPA how such a pilot program in the 2014 Plan could provide those types of results in time for meaningful decisions that could inform future procurement plans.

The IPA indicates that a call option could be used to hedge against future energy price increases if more load switches back to the utilities than forecasted. The IPA says a put option could be used to hedge against energy price decreases if additional load switches from the utility; load loss due to additional switching compounds the financial risk of out-or-market hedges. The IPA indicates it did not conduct a full analysis of the economic and regulatory implications of including options in the 2014 Procurement Plan; however, the IPA plans to investigate those implications in developing its 2015 Procurement Plan.

Section 16-111.5(b)(4)(ii) requires that a procurement plan include "the criteria for portfolio re-balancing in the event of significant shifts in load." Historically, the IPA has used the utilities' updated March forecasts as the criteria for determining whether to re-balance a utility's portfolio. In particular, in last year's plan, the IPA focused specifically on the impacts to the forecast resulting from municipal aggregation in determining the need for re-balancing the portfolio. Once again, the IPA proposes to use the utilities' updated March 2014 forecasts for the purposes of determining whether to re-balance the portfolio. Also, once again, municipal aggregation will be the primary criteria for making that determination. The IPA notes that numerous supply contracts for municipal aggregation will be expiring in the 2014 Planning Year. The IPA suggests that the utilities should survey all such municipalities and on the basis of those surveys update their March 2014 forecasts accordingly.

The IPA reports that in the 2013 Plan, the IPA noted that Ameren was substantially over-hedged and considered the benefits and drawbacks of holding the long position and allowing the hedges to settle in the MISO day-ahead market (as opposed to organizing a reverse RFP).

The IPA believes that the risk of holding a long position could be mitigated by selling excess supply in the forward market in mid-September 2014. The IPA claims this belief is supported by its quantitative analysis. However, the IPA says in practice the expected cost of holding the reverse RFP and the expectation that bidders would bid to buy the excess supply at or below the bid mark, could reduce the estimated benefit and produce a real financial loss that is perhaps equal or greater than the estimated avoided risk of holding the long position, about $0.30/MWh, plus $0.06/MWh in avoided expected cost. Additionally, the IPA notes that the excess supply in the Ameren portfolio is comprised of supply acquired as the result of mandated rate stability procurement; it is unclear whether selling such supply back to the market is permissible or prudent. The IPA, for these reasons for the 2014 Plan does not recommend that Ameren rebalance its portfolio in an organized reverse auction and therefore recommends the position settle within MISO at the prevailing LMP.

4. Block Energy

The IPA provides extensive tables demonstrating the quantities of block energy to be purchased during the mid-April 2014 procurement as well as the proposed supplemental procurement in mid-September 2014 procurement. The tables below summarize the tables presented by the IPA.

Mid-April 2014 Procurement for Plan Year

	Ameren Required Purchases (MW)		ComEd Required Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-14	75	0	1000	775
July-14	175	50	1175	900
Aug.-14	150	0	1125	850
Sept.-14	0	0	925	600
Oct.-14	0	0	675	400
Nov.-14	0	0	350	200
Dec.-14	0	0	450	375
Jan.-15	0	0	425	350
Febr.-15	0	0	400	300
March-15	0	0	350	175
April-15	0	0	225	75
May-15	0	0	225	125

Mid-Sept. 2014 Supplemental Procurement

	Ameren Required Mid-Sept. 2014 Purchases (MW)		ComEd Required Mid-Sept. 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Nov.-14	0	0	325	275
Dec.-14	0	0	350	300
Jan.-15	0	0	350	325
Febr.-15	0	0	350	300
March-15	0	0	300	250
April-15	0	0	275	225
May-15	0	0	300	225

Mid-April 2014 Procurement for Plan Year + 1

	Ameren Required Mid-April 2014 Purchases (MW)		ComEd Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-15	75	25	200	50
July-15	150	75	375	175
Aug.-15	125	50	325	125
Sept.-15	25	0	125	0
Oct.-15	0	0	0	0
Nov.-15	0	0	0	0
Dec.-15	25	25	125	25
Jan.-16	25	25	125	0
Febr.-16	50	25	100	0
March-16	0	0	0	0
April-16	0	0	0	0
May-16	0	0	0	0

Mid-April Procurement for Plan Year + 2

	Ameren Required Mid-April 2014 Purchases (MW)		ComEd Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-16	125	100	0	0
July-16	150	125	0	0
Aug.-16	150	100	0	0
Sept.-16	100	75	0	0
Oct.-16	50	50	0	0
Nov.-16	75	50	0	0
Dec.-16	100	100	0	0
Jan.-17	100	100	0	0
Febr.-17	100	75	0	0
March-17	75	50	0	0
April-17	50	25	0	0
May-17	75	50	0	0

Given the absence of visible and liquid block energy markets four and five years out, the IPA does not recommended that any block energy purchases be made to secure supply for these years in the 2014 Procurement Plan.

5. Ancillary Services and Transmission Service

The IPA indicates that both Ameren and ComEd have been purchasing their ancillary services and transmission services from their respective RTOs, MISO and PJM. The IPA says the utilities have also been managing their FTRs and ARRs in their respective RTOs consistent with Commission Orders in prior plans. The IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged.

6. Capacity

The IPA concludes that it does not need to include any extraordinary measures in the 2014 Procurement Plan to assure reliability over the planning horizon.

The IPA recommends that ComEd continue to meet all of its capacity obligations through the PJM capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules. In case of any excess capacity credits PJM subsequently issue to ComEd, the IPA suggests ComEd sell its excess capacity credits and return the corresponding proceeds to its customers.

The 2013 Procurement Plan recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction. Based on the July 2013 forecast, the table below shows how much capacity that strategy would require Ameren to procure.

Ameren Capacity Requirements

Delivery Year	Capacity Requirements (MW)
2014-2015	180
2015-2016	820
2016-2017	400
2017-2018	1064
2018-2019	1014

The IPA states that in 2013, MISO's first annual capacity auction cleared the entire capacity requirement and the 2014 auction should have the liquidity to supply the 180 MW Ameren will need. The IPA expects that auction to demonstrate sufficient liquidity that it will be unnecessary to purchase capacity for 2015-2017 bilaterally. The IPA therefore recommends there be no capacity procurement event in 2014. However, the IPA is also aware that MISO has a prompt year capacity auction whereas PJM has a three-year forward capacity auction. If Ameren were to rely entirely on the prompt year capacity auction in perpetuity (with no bilateral procurements via the IPA), it could increase the chances that Ameren's eligible retail customers would be exposed to a scarcity pricing event whereby capacity prices rise abruptly and dramatically. The IPA therefore recommends that the procurement of bilateral capacity for Ameren be revisited in future Plans in the absence of a more robust forward looking MISO capacity auction.

7. Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures. The energy efficiency and demand response programs for the three-year period starting June of 2014 for Ameren and ComEd pursuant to Section 8-103 have not yet been filed, or approved by the Commission, so the IPA says it does not have concrete information regarding how the utilities will meet their demand response goals.

ComEd provided information to the IPA regarding its existing demand response programs for 2012, which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 71,900 customers with a load reduction potential of 87 MW (ComEd Rider AC).

- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,010 MW of potential load reduction (ComEd Rider VLR).

- Residential Real-Time Pricing ("RRTP") Program: All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has roughly 5 MW of price response potential.

- Peak Time Savings ("PTS") Program: This program is required by Section 16- 108.6(g) of the PUA and was recently approved by the Commission in Docket No. 12-0484. The PTS program is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commences with the 2015 Planning Year. ComEd recently sold 35 MW of capacity from the program into the PJM capacity auction for the 2016 Planning Year.

The IPA indicates that Ameren has a Voltage Optimization Pilot Program underway, offers the Power Smart Pricing real-time pricing program to residential customers, and has a proceeding underway before the Commission to approve a Peak Time Rebate program.

The IPA does not propose any additional demand response programs for the 2014-2015 delivery year. Peak Time Rebate (or Savings) programs create value through reduction in capacity charges. Given that the IPA has recommended that the utilities directly contract for capacity, the IPA does not have a direct role in the use of demand response to reduce capacity obligations. However, the IPA says the technologies utilized for capacity reductions also have the potential to provide longer term demand response that could operate over more peak hours than those used for calculations of capacity obligations. With the ComEd Peak Time Savings program scheduled to commence in 2015, and the likely start-up of a similar program for Ameren in 2016, the IPA invites stakeholders to provide comments to the IPA on how the Procurement Plan should include additional or complimentary demand response, and whether the roll-out of smart meters affects the timeline for additional programs.

8. Clean Coal

The IPA says it did not receive any requests for Clean Coal projects pursuant to Sections 1-58 or 1-75 of the IPA Act.

E. Renewable Resources

Procurement on behalf of eligible retail customers is subject to targets for purchase volumes and upper limits on customer bill impacts, which, based on the load forecast, creates a cap on the available budget. From 2009 through 2012, the IPA's annual electricity procurement plans included purchase of renewable energy resources sufficient to meet the RPS applicable to the eligible load of ComEd and Ameren. In 2013, the IPA determined that resources under contract were sufficient to meet the reduced eligible load. The RPS calls for the procurement of the following quantity of renewable energy resources and renewable energy credits as a mandatory part of each utility's annual supply:

- At least 2% by June 1, 2008
- At least 4% by June 1, 2009
- At least 5% by June 1, 2010
- At least 6% by June 1, 2011
- At least 7% by June 1, 2012
- At least 8% by June 1, 2013
- At least 9% by June 1, 2014
- At least 10% by June 1, 2015

This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025. The obligation of each electric utility is determined by applying the required percentage to the amount of eligible retail sales from the most recently completed delivery year. In addition, the RPS mandate includes targets for specific resource types: wind, photovoltaics ("PV") and distributed generation.

The IPA does not recommend procuring any additional renewable resources on behalf of Ameren or ComEd during the planning horizon nor does the IPA recommend the sale of any renewable resources that exceed targets for Ameren. Furthermore, the IPA recommends that the Commission order the utilities to produce updated load forecasts in March and to curtail the Long-Term Power Purchase Agreements ("LTPPAs") if the updated forecast indicates the renewable budget will be exceeded. The IPA says these forecasts will also be used to plan the Mid-April 2014 forward hedge procurement event.

According to the IPA, Ameren's current renewable contracts will cover its RPS targets for the next four Delivery Years. Assuming that no additional purchases of renewable energy are made, Ameren will fall short of meeting its RPS requirements in the 2018-2019 delivery year by less than 2%.

The IPA Act also sets separate goals for wind, photovoltaic and distributed renewable generation as fractions of the total renewables requirement.

The table below shows that Ameren is projected to meet its wind generation goals for the next five delivery years, but, assuming that no additional purchases of PV and DG are made, Ameren will fall short of the photovoltaic and distributed generation goals in each year. As explained more fully below, the IPA says Ameren is also projected to exceed its spending cap on renewables. Therefore the IPA does not recommend procuring any additional renewable resources on behalf of Ameren during the planning horizon.

Ameren's Existing RPS Contracts and RPS Requirements

Delivery Year		Total Renewables	Wind	Photovoltaics	Distributed Generation
2014-2015	Target (MWh)	949,030	711,773	28,471	7,118
	Purchased (MWh)	1,025,366	949,672	8,694	0
	Remaining Target (MWh)	-76,336	-237,899	19,777	7,118
2015-2016	Target (MWh)	540,550	405,412	32,433	5,405
	Purchased (MWh)	1,008,810	979,916	8,894	0
	Remaining Target (MWh)	-468,260	-574,504	23,539	5,405
2016-2017	Target (MWh)	544,472	408,354	32,668	5,445
	Purchased (MWh)	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	-484,773	-568,497	20,274	5,445
2017-2018	Target (MWh)	572,930	429,697	34,376	5,729
	Purchased (MWh)	854,396	848,338	6,058	0
	Remaining Target (MWh)	-281,466	-418,641	28,318	5,729
2018-2019	Target (MWh)	607,991	455,993	36,479	6,080
	Purchased (MWh)	600,000	596,571	3,429	0
	Remaining Target (MWh)	7,991	-140,578	33,050	6,080

The table below shows ComEd's current RPS contracts relative to its renewables requirements. ComEd's forecast indicates that it has a relatively small shortage of 116 gigawatt-hours of renewables for the 2014-2015 delivery year. However, as discussed below, ComEd expects to exceed the renewables cost cap and therefore cannot procure any additional renewables. Based on current forecasts, ComEd will meet its RPS requirement, with comfortable surpluses, in the next three years. The IPA does not recommend procuring additional renewable resources on behalf of ComEd during the planning horizon.

ComEd's Existing RPS Contracts and RPS Requirements

	Total Renewables			Other Targets (MWh)		
Delivery Year	Target (MWh)	Purchased (MWh)	Remaining Target (MWh)	Wind	Photovoltaics	Distributed Generation
2014-2015	2,001,744	1,885,302	116,442	1,501,308	60,052	15,013
2015-2016	1,171,086	1,464,204	-293,118	878,315	70,265	11,711
2016-2017	1,198,607	1,561,397	-362,790	898,955	71,916	11,986
2017-2018	1,300,312	1,533,198	-232,886	975,234	78,019	13,003
2018-2019	1,439,620	1,261,725	177,895	1,079,715	86,377	14,396

The table above includes ComEd's statutory targets for wind, photovoltaic and distributed renewable procurement over the five-year projection horizon. The rate cap prevents procurement of these or any other resources on behalf of eligible retail customers as long as the cap is exceeded.

The IPA notes that the significant decrease in RPS target observed between Delivery Years 2014-2015 and 2015-2016 reflects the drop in eligible load that occurred between Delivery Years 2012-2013 and 2013-2014. The statutory RPS obligations of Ameren and ComEd are determined by their amount of actual eligible retail sales two years earlier.

As noted above, the IPA Act includes a limit on each utility's spending on renewable procurement. For the 2013-2014 delivery year, the Commission approved the curtailment of Ameren and ComEd's existing long-term renewables contracts to keep the cost of renewable energy resources under the statutory cap. This approval was subject to the March 2013 forecast indicating the renewable budget was exceeded. Since ComEd's March 2013 forecast indicated that its budget was exceeded and Ameren's was not, ComEd initiated curtailments whereas Ameren did not (Ameren's current forecast suggests it be obliged to curtail in the coming years).

Ameren LTPPA Curtailments Required to Meet Spending Cap

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction
2014-2015	9,167,145	8,547,742	619,403	8,155,000	7.6%
2015-2016	9,183,529	7,956,671	1,226,858	7,826,000	15.7%
2016-2017	10,403,861	7,570,119	2,833,742	7,796,000	36.3%
2017-2018	9,412,155	7,216,201	2,195,954	7,957,000	27.6%
2018-2019	8,000,000	6,860,913	1,139,087	8,000,000	14.2%

This table indicates that under its current RPS contracts and given the expected load forecast, Ameren is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon.

ComEd LTPPA Curtailments Required to Meet Spending Cap

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction
2014-2015	24,272,678	19,716,565	4,556,113	23,189,000	19.6%
2015-2016	23,159,931	18,921,538	4,238,393	22,613,000	18.7%
2016-2017	23,483,757	18,781,575	4,702,182	22,676,000	20.7%
2017-2018	23,776,890	18,875,753	4,901,136	23,139,000	21.2%
2018-2019	23,415,145	18,980,868	4,434,278	23,358,000	19.0%

The table immediately above shows ComEd's contractual RPS supplies and cost relative to the cost cap, given the expected load forecast. Like Ameren, ComEd is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon – as it did in the current delivery year, forcing curtailment of ComEd's LTPPAs.

The spending caps will prevent ComEd and Ameren from committing any additional money to procure renewables for the 2014-2015 delivery year, including specific procurements of wind, photovoltaic, and distributed renewables. According to the IPA, in future years if the load forecast is significantly different, then these caps may cease to apply. The IPA states that for the purposes of this plan, the spending caps preclude the procurement of renewable energy resources in 2014.

Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory cap. Therefore, the purchases under the long term renewable contracts will need to be reduced. The IPA says an estimate of the overall amount is shown in the 2014 Plan for both Ameren and ComEd, however the exact amount is uncertain at this time. Both utilities will be submitting updated forecasts in March 2014. Once the Commission has approved the 2014 Plan, including the incremental energy efficiency program amounts, and the utilities have submitted further updated forecasts in March 2014 to reflect municipal aggregation activity and any Commission-approved energy efficiency programs, the IPA says each utility should calculate both the overall amount of the necessary reduction to keep the purchases under the statutory cap, and determine the amount that each long term renewable contract will need to be reduced. The IPA believes any such reductions should be applied proportionately to the long-term renewable contracts consistent with the terms of the contracts. The IPA says this calculation should only be made for the 2014-15 delivery year. Future procurement plans will address the need, if any, for additional reductions.

According to the IPA, the updated March 2014 forecast and related calculations of the curtailments, if any, should be submitted to both the IPA and the Commission Staff for their review and acceptance. Once the utilities have received written acceptance from both the IPA and the Commission Staff, the utilities may then notify the suppliers under the long-term renewable contracts of the amounts of the reductions. The IPA says the suppliers will then make the election allowed them under the agreements. Because the reductions under the IPA Act are to be made on the basis of the "estimated" net increase in charges to Eligible Retail Customers, no further reductions in purchases of renewable under the long-term contracts for delivery year 2014-2015 will be made based on either the suppliers' elections or the actual increases in charges experienced by Eligible Retail Customers during the 2014-2015 delivery year.

As the Commission ordered in its approval of the 2013 Procurement Plan, the IPA recommends March 2014 updates to both utilities' load forecasts. These forecasts will form the basis for curtailment upon consensus of the utilities, IPA, Commission Staff, Procurement Administrator(s) and Procurement Monitor. To the extent that the Commission authorizes block energy procurements for ComEd or Ameren, the IPA notes that additional load forecasts will be required in anticipation of the procurement event and the load forecast should not be duplicated. As with Ameren's March 2013 load forecast, the IPA says one or both of the utilities may have unanticipated changes in their respective load forecasts from the previous forecasts such that curtailments are not warranted.

The IPA notes that the utilities collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility. Unlike the ACP funds paid by ARES into the RERF, the utility hourly customer ACP funds are held by the utilities. As required by the IPA Act, the IPA says each utility has disclosed the amount of hourly customer ACP funds being held; for Ameren, the value is $1,800,484; for ComEd, the value is $4,099,937.

The IPA Act requires the ACP funds from utility hourly customers to increase the utility's spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31. The IPA states that in the Commission's Final Order in the 2013 Procurement

Plan approval docket, the Commission accepted the IPA's proposal that the utility hourly customer ACP funds should be used to purchase curtailed RECs at the imputed REC price. As approved by the Commission in Docket No. 09-0373, the imputed REC price under the bundled renewable contracts is equal to the difference between the Contract Price and the forward price curve for each respective load zone for a particular year, as developed by the Procurement Administrator in 2010.

During the pendency of the approval docket for the 2013 Procurement Plan, the IPA says it and several stakeholders anticipated that the LTPPA contracts entered into by both Ameren and ComEd could face curtailment. The IPA reports that in the end, only ComEd implemented an ICC-approved curtailment.

In the event that the Commission approves curtailments based on March 2014 load forecasts, and after consensus of the aforementioned parties, then the IPA recommends that the Commission once again approve use of the utility hourly customer ACPs to purchase curtailed RECs at the imputed REC price. While several parties argued that using these funds could be counter to the statute and could be construed as a supplier subsidy by utility hourly priced customers, the Commission agreed with the IPA that this was an appropriate use of such funds and the IPA again asks for the same approval in this Plan. If, due to load shifts or change in law, the Commission does not approve curtailments and does approve additional procurements, then the IPA recommends that the Commission authorize the IPA to use those funds to supplement any renewable resource procurements.

If the Commission approves procurements of multiple renewable resource products for a single utility, then the IPA requests that the Commission authorize use of the utility hourly customer ACP funds to the highest renewable resource procurement priority.

The IPA indicates that the RERF balance currently equals $14,911,284.40, the total amount received in the IPA's RERF attributable to ARES ACP payments. The table below shows the current IPA RERF balance sheet. In September 2013, the IPA expects to receive an estimated $40 million in ACPs for the June 2012 – May 2013 planning year. The IPA says these expected payments, in the aggregate, are significantly higher than prior year payments. According to the IPA, the higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

RERF Balance

Planning Year	Funds Received	Total ACPs
2009-2010	2010 - Quarters 3 and 4	$7,148,261.61
2010-2011	2011 - Quarters 3 and 4	$5,606,245.18
2011-2012	2012 - Quarters 3 and 4	$2,156,777.61
Aggregate Total		**$14,911,284.40**

The Commission has held that it does not have jurisdiction over the RERF, and as a result the IPA is not seeking approval for procurement using the RERF. However, for informational purposes, the IPA believes it would be beneficial to explain its plans for spending the RERF and allow the Commission and stakeholders to coordinate the Commission jurisdictional Procurement Plan spending with the IPA's RERF spending.

As the IPA noted in the 2013 Procurement Plan docket, the IPA faces statutory and practical barriers to spending the RERF absent a procurement event on behalf of eligible retail customers. The IPA says it has worked with stakeholders on the elements of a legislative solution to address the problems inherent in the statute as currently written. The IPA indicates that Section 1-56 of the IPA Act authorizes spending of the RERF on the same products procured for utility customers at the same or lesser price. In the absence of a procurement event for eligible retail customers, the IPA says there are no "same products" and no price target. Furthermore, even if the IPA were to ignore these statutory requirements, the IPA says it does not have the statutory authority to recover the significant costs of a procurement. It appears to the IPA that the statute envisioned the RERF as an add-on to budget for a utility procurement and the IPA does not have the authority to create an enforceable cost-based benchmark with the Commission. As a result, absent a change in law to address these issues or a procurement on behalf of eligible retail customers, the IPA does not believe that it can spend the RERF on anything except curtailed RECs.

If there are no changes in law and the Commission does not authorize renewable resource procurements on behalf of eligible retail customers, then the IPA will plan to spend some of the RERF funds on curtailed RECs on a one-year basis. The IPA is currently taking this action for RECs curtailed by ComEd in the current delivery year. In the current year, the IPA plans to purchase up to 121,620 curtailed RECs at a total expected cost of up to $2.24 million.

If there are no changes in law and the Commission does authorize renewable energy resource procurements on behalf of eligible retail customers, then the IPA will use some or all of the RERF to expand the budget for the procurements according to the IPA's highest product priorities.

If there are changes in law sufficient to allow the IPA to procure renewable energy resources at the IPA's discretion and not necessarily in conjunction with a utility procurement, then the IPA plans to spend funds from the RERF in accordance with the provisions of Section 1-56(b). In particular the IPA will seek to achieve the goals for procuring solar and distributed renewable energy resources. Section1-56(b) also specifies that 75% of resources procured come from wind. The IPA says it will analyze the quantities of wind procured via the purchase of curtailed RECs described above and will fill the balance of the requirement with RECs from existing wind energy facilities.

To the extent that the Commission authorizes a procurement event on behalf of eligible retail customers and the IPA also has discretion to procure renewable resources using the RERF, then the IPA plans to work with the Commission and stakeholders to ensure coordination between procurement events and products procured to minimize expenditure of resources and meet state renewable targets.

In the draft plan for public comment released on August 15, 2013, the IPA set out a priority list for renewable resource procurement. The IPA notes the load forecasts for Ameren and ComEd indicate that there will be a curtailment in the LTPPAs during the upcoming delivery year. The IPA also indicates the renewable resource budgets will be exceeded for each utility and thus no procurements will take place. Although the IPA continues to recommend the prioritization set forth in the August 15, 2013 public comment draft plan, the IPA removed the discussion because potential statutory changes are insufficiently definite to provide a meaningful backdrop for discussion at this point in time.

F. Process Design

"Procurement Process Design" is addressed in Section 9.0 of the proposed Plan. The procedural requirements for the procurement process are detailed in Section 16-111.5 of the PUA. The procurement administrators, retained by the IPA in accordance with Section 1-75(a)(2) of the IPA Act, conduct the competitive procurement events on behalf of the IPA. The costs of the procurement administrators incurred by the IPA are recovered from the bidders and suppliers that participate in the competitive solicitations through both Bid Participation Fees and Supplier Fees assessed by the IPA. The IPA says that as a practical matter, the utility's "eligible retail customers" ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the IPA and the procurement administrators have reviewed the process for potential improvements.

The IPA indicates that the PUA requires the procurement process must include the following components:

1. Solicitation, pre-qualification, and registration of bidders.
2. Standard contract forms and credit terms and instruments.
3. Establishment of a market-based price benchmark.
4. Request for proposals competitive procurement process.
5. A plan for implementing contingencies.

The IPA asserts that of these five process components, the area with the greatest potential for efficiency improvements resulting in lower costs passed along to ratepayers is item (2): development of standard contract forms and credit terms and instruments. The IPA believes that the forms can be further standardized while remaining acceptable to future potential bidders, thus reducing procurement administrator time and billable hours, while shortening the critical-path time needed to conduct a procurement event. This is because the forms, terms and instruments have become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. The IPA also notes that the contracts with the incumbent procurement administrators have expired and the IPA will be conducting a competitive procurement process for a new procurement administrator starting this fall. The IPA suggests there may be additional cost savings to be realized by having a single procurement administrator rather than a different administrator for each utility.

The IPA states that any procurement process to be conducted under the auspices of the 2014 Procurement Plan would be the seventh iteration of IPA-run procurements, when including the February 2012 Rate Stability procurements and the December 2010 long-term REC and energy procurement. In each of the prior iterations, the IPA says potential bidders have had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. In the two procurements conducted in 2012 (the Rate Stability Procurement and the standard Spring Procurement) comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurements). The IPA says the documents used for the 2012 IPA-run procurements illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves.

On the opposite side of this discussion, the IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection of the utilities, utility customers, and suppliers. The IPA recommends that the energy contracts used in the February 2012 Rate Stability procurements be the starting point for the contracts used in the energy procurements associated with this plan. The IPA plans to work with the Procurement Administrator, the Procurement Monitor, the Commission and other stakeholder to implement additional procurement process improvements suggested in comments.

The IPA reports that because there have been no procurements in 2013, no informal comment process was conducted this year pursuant to Section 16-111.5(o) of the PUA. The IPA notes that comments from previous informal hearings are available of the Commission's web site.

IV. DISPUTED ISSUES

A. Full Requirements Products

1. ICEA's Position

ICEA states that the IPA Plan continues to rely upon a procurement and risk management strategy it refers to as "block-and-spot" that ICEA believes places too much risk onto customers that remain on or return to bundled "default service" and also fails to allow such customers to see the actual and transparent price for electricity which they will ultimately be required to pay to ComEd or AIC. ICEA says while these costs do not always immediately flow through to customers, they do exist and are increasing, as the most recent ComEd PEA filing shows. ICEA believes continuing to implement procurement practices which accrue charges with interest when customers move among suppliers is something the Commission should consider in light of the now thriving market. (ICEA Objections at 4)

According to ICEA, the block-and-spot approach involves managing an energy supply portfolio for default service customers consisting of fixed-quantity, fixed-price block energy products supplemented with spot market transactions to cover the mismatch between the fixed quantities of fixed-price supply purchased and actual load requirements. ICEA says the block-and-spot approach avoids the customer payment of some embedded “premiums” in product prices because the products underlying the block-and-spot approach do not require suppliers to provide insurance against a host of adverse market and regulatory risks. ICEA states at the same time, the block-and-spot approach can result in significant unintended adverse consequences for customers if actual market outcomes differ materially from expectations, such as through unexpected swings in load and/or market prices. In ICEA's view, the customer may avoid paying for the known insurance cost and instead end up paying the full unknown cost of the consequences on the back end. (ICEA Objections at 5)

ICEA contends that under the block-and-spot procurement approach, there is an inherent inability to match and follow load on a daily basis and thus causes ComEd and AIC to conduct additional daily transactions in the PJM and MISO markets in order to match the actual load of the default service customers. ICEA states any costs incurred through these supplemental transactions (buying and selling) are settled through the PEA tariff, which default service customers are obligated to pay monthly through a separate charge on their electric bill. ICEA says that default service customers pay not only the price-to-compare ("PTC") tariff rate for their supply, but also any additional "transactional costs" needed to match load on a daily basis under the IPA's block-and-spot procurement approach. ICEA claims the transactional costs which customers must pay monthly through the PEA distorts the price comparison between ARES competitive pricing and the PTC tariff rate for electricity supply due to the block-and-spot procurement strategy. (ICEA Objections at 5)

ICEA states in theory, the additional transactional costs incurred through the block-and-spot procurement approach can be either positive or negative for default service customers, depending upon whether the electric supply previously purchased is "short" or "long" to actual daily demand and load. In addition, ICEA says where the IPA has also incorporated a three-year laddered hedging strategy to augment the block-and-spot approach, more often than not, additional electric supply purchases must be made to match the daily load demand for default service customers. According to ICEA, recent history demonstrates that the additional costs for purchasing electricity have far outweighed any revenues collected for selling power back into the market through the block-and-spot strategy. In ICEA's view, a procurement approach that is continuously reflective of current wholesale prices provides the best environment for customers as well as for a sustainable and robust retail market in which customers enjoy price transparency and the opportunity for true apples-to-apples price comparisons. (ICEA Objections at 6)

ICEA says the full requirements product approach involves procuring full requirements products on a competitive basis to satisfy the default service supply needs, with each full requirements product obligating the seller of the product to satisfy a specified percentage of all of the default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. ICEA states the seller is paid a predetermined price per megawatt-hour for this service. ICEA claims the full requirements approach ensures that customers who leave default service are not avoiding costs they created and customers who return to default service are not paying for the costs created by a customer who left service, cost causation being a fundamental principle of sound regulatory policy. (ICEA Objections at 6-7)

The Plan contains an assessment of the possibility of including full requirements products in the supply portfolio for eligible retail customers. ICEA notes the full requirements approach was a contested issue in the 2012 IPA Plan during the Commission's proceeding in Docket No. 11-0660. ICEA states that in that Docket, Constellation NewEnergy, an ICEA member company, recommended that the Plan be modified to use Full Requirements products. ICEA claims that full requirements is consistent with the PUA. In that Docket, the IPA stated that it was willing to discuss the use of full requirements products in future procurement plans; however, the IPA continues to believe that its current approach continues to be preferable to full requirements contracts. (ICEA Objections at 7)

While the IPA's 2014 Plan includes an assessment of full requirements products as compared to the block-and-spot approach, ICEA asserts the IPA's findings and conclusions regarding full requirements products are incomplete and inaccurate because the analysis is significantly flawed, and because other evidence and analysis demonstrates the potential benefits of including full requirements products in the IPA's supply mix. To support this contention, and to provide the Commission with a more complete record upon which to render a decision on this issue, ICEA provides a Report entitled, "Merits of Incorporating Fixed-Price Full Requirements Products in the Illinois Power Agency Plan," prepared by Mr. Scott Fisher of the NorthBridge Group ("NorthBridge" or "NorthBridge Report"). (ICEA Objections at 7)

According to ICEA, the NorthBridge Report addresses both the full requirements product approach and the block-and-spot approach, which are the two types of supply procurement approaches that generally have been employed by regulatory agencies, procurement administrators, and electric distribution utilities when procuring power for residential and small commercial default service customers. (ICEA Objections at 8)

ICEA says the NorthBridge Report notes that most restructured jurisdictions have concluded that the risks of unanticipated market prices and loads, which are borne by customers under the block-and-spot approach, are large enough to be concerned about and have chosen to rely predominantly on full requirements products for their default service supply for smaller customers. ICEA claims these jurisdictions believe that the added price protection that full requirements products offer justify the compensation required by full requirements product suppliers to bear the risks of unanticipated market prices and loads to the benefit of customers. ICEA alleges that for the forgoing reasons, the full requirements product approach has become the most prevalent form of default service supply procurement for smaller customers in restructured jurisdictions, and there are many sellers willing to compete on the basis of lowest price to provide full requirements products. (ICEA Objections at 8)

ICEA also says NorthBridge conducted an analysis that shows that customers in Illinois have been subject to costs and unnecessary adverse financial risks under the block-and-spot approach. According to ICEA, the additional energy supply cost embedded in the June 2012-May 2013 ComEd Purchased Electricity supply charges, due to the fact that the supply products under the block-and-spot approach could not "follow the load" like full requirements products do, was approximately $9/MWh. ICEA states the PEA, which is an additional supply charge that bundled service customers incur to cover additional unanticipated supply costs, was on average an additional almost $3/MWh during this time. ICEA also says the significant monthly variations in the PEA that are necessitated by the supply/load mismatches under the block-and-spot approach distorted the bundled service rates against which ARES competed. ICEA asserts that recent ComEd data also indicates that, in a period spanning only three months, the block-and-spot approach caused almost $100 million in additional costs that must be deferred for recovery from customers in future periods. (ICEA Objections at 8-9)

ICEA claims these "deferred balances" are the accumulation of the portion of the transaction costs incurred through the block-and-spot procurement approach, which exceed the "5% cap" for customers monthly through the PEA. To avoid potential "rate shock" to default service customers, ICEA says the maximum amount for energy supply costs which can be charged monthly is capped at 5%. According to ICEA, any costs not charged to default service customers in that month which exceed the cap are not eliminated, but deferred for payment in the future through the deferred balances where such unpaid costs are captured. ICEA alleges these deferred balance charges are unknown to all residential customers who are trying to choose between either the default service provider or an ARES. Since neither the electricity costs incurred through spot transactions incurred via the block-and-spot approach nor the deferred costs held in the deferred balances are included in the PTC, ICEA asserts default service customers are unable to properly evaluate the true comparison in price offerings between the ARES and the utility default service price. (ICEA Objections at 9-10)

ICEA alleges, based upon the NorthBridge Report, it has a solution to address this issue, as well as other problems associated with the IPA's sole reliance on the block-and-spot approach. ICEA says the Northbridge Report finds that full requirements products easily can be integrated in a portfolio that already includes block energy products, like the Illinois utilities' supply portfolios, to help protect customers from the significant adverse financial risks and rate instability associated with a portfolio based entirely on the block-and-spot approach. (ICEA Objections at 10)

ICEA claims NorthBridge also has conducted a detailed review of the IPA's analysis about the relative merits of the full requirements product approach as compared to the IPA's proposed block-and-spot approach. ICEA says the NorthBridge Report concludes that the IPA's analysis of the two approaches contains significant shortcomings that invalidate the IPA's conclusions. (ICEA Objections at 10-11)

According to ICEA, the full requirements products could be designed like those in almost every other jurisdiction, in which the full requirements product suppliers must serve a cross-section (pro-rata) of the entire actual load requirement. ICEA says the remaining cross-section would be supplied through the block-and-spot approach (i.e., the residual load requirements, above the supply product quantities, would be satisfied through purchases and sales in the spot market, as they are now). ICEA claims this method of integrating full requirements products, which it says apparently was overlooked by the IPA, effectively separates the load into two portions: one that is entirely supplied by full requirements products and one that is entirely supplied by the block-and-spot approach. First, ICEA claims this method has several benefits relative to the method suggested by the IPA. ICEA says it should be fairly simple to implement. ICEA says the portion of the load to be supplied by full requirements products would be a fixed percentage share of the entire actual hourly load requirement, and therefore it would allow for full requirements products that are structurally similar to those solicited elsewhere. Meanwhile, ICEA says the portion of the load to be supplied by the block-and-spot approach could operate exactly like that proposed by the IPA, but the overall supply quantities would be scaled down to accommodate the portion of the load that is supplied by full requirements products. Second, ICEA states by not requiring full requirements product suppliers to bear the entire load risk while only serving a "residual" load ("above" or "on top of" block products), the prices of the full requirements products would be reduced. Third, ICEA says because the full requirements products would supply a cross-section of the load, their prices could more easily be compared to expectations about the market costs of various components of the full requirements supply obligation as of the times of the full requirements product solicitations. (ICEA Objections at 11-12, Response at 3)

ICEA contends that in contrast to the IPA's analysis, NorthBridge presents a robust quantitative analysis based on actual market data from a region in which the block-and-spot approach and the full requirements product approach simultaneously had been implemented. ICEA says this analysis indicates that the compensation that full requirements product suppliers require to directly bear costs and risks to the benefit of customers is reasonable. According to ICEA, the analysis indicates that, in comparison to the full requirements product approach, the increases in risk borne by residential customers under the block-and-spot approach are not balanced by a proportionate decrease in the expected default service rate level. (ICEA Objections at 12-13)

ICEA says the NorthBridge Report concludes that, given these facts, the prospect of continuing with a full block-and-spot procurement approach is particularly troubling, especially in light of the Illinois General Assembly's finding that Illinois citizens should be provided "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 says NorthBridge recommends that full requirements products be included in the IPA Plan. To the extent that these products are included, ICEA says NorthBridge argues that they will protect customers from the adverse risks of the block-and-spot approach, and more information will be gained about their pricing in the context of the Illinois electricity markets. (ICEA Objections at 13)

Based upon the NorthBridge Report, ICEA proposes that the Plan be refined to include an initial amount of full requirements products in the supply portfolio to serve ComEd's eligible retail customers. Specifically, ICEA proposes that the IPA Plan be refined so that 30% of the bundled service load of ComEd's eligible retail customers will be supplied through full requirements products during the June 2014-May 2015 period, leaving the possibility for further full requirements product procurements to be included in future IPA Plans. ICEA proposes all of the June 2014-May 2015 full requirements products will have a 12-month delivery period covering the entire June 2014-May 2015 period. ICEA says the products will be competitively procured in an RFP process that will run concurrently with the mid-April 2014 block energy RFP that is already included in the IPA Plan. According to ICEA, twenty "tranches" of this product will be solicited, with each tranche supplying 1.5% of the bundled service load. ICEA says bidders will submit fixed-price $/MWh bids to supply the full requirements product. ICEA proposes for full requirements product tranches to be awarded on the basis of lowest price. (ICEA Objections at 13-14)

ICEA says under its proposal, each full requirements product tranche will supply a fixed percentage of the entire bundled service load requirement (for eligible retail customers) in every hour based on actual (as opposed to forecasted) load. According to ICEA, the 70% cross-section of the load not supplied through the full requirements products will be supplied through the block-and-spot approach (i.e., in this cross-section, the residual load requirements above the block product quantities will be satisfied through purchases and sales in the spot market, as they are now). ICEA says this approach effectively separates the June 2014-May 2015 bundled service load into two portions: one that is entirely supplied by the block-and-spot approach, and one that is entirely supplied by full requirements products. (ICEA Objections at 14)

According to ICEA, the block-and-spot approach used to supply the 70% cross-section will operate exactly like the approach currently proposed by the IPA in its Plan (with a procurement goal for a mid-April 2014 RFP to hedge 106% of the forecasted load for June 2014-October 2014 and 75% for November 2014-May 2015, and a mid-

September 2014 RFP to hedge 106% of the forecasted load for November 2014-May 2015). ICEA says the overall block energy supply quantities on a megawatt basis will be lower than they would be if the 30% full requirements product cross-section did not exist, because the block product targets will be based on 70% of the overall forecasted load as opposed to 100% of the forecasted load. (ICEA Objections at 15-16)

ICEA proposes that consistent with the Plan, actual block energy product quantities to be procured will be based on updated load forecasts. ICEA asserts that even with the carve-out of 30% of the bundled service load for the full requirements products, the pre-existing quantities of block energy supply are unlikely to exceed the hedge targets; in fact, additional block energy product procurements are still likely to be required to meet the targets (for the 70% block-and-spot cross-section of the load) in 2014. ICEA says this is not the case for AIC, which already is oversubscribed in terms of supply products procured in relation to its forecasted load in most months of the June 2014-May 2015 period. Unless the Commission is willing to liquidate some of AIC's pre-existing supply products, ICEA's proposal does not involve carving out a cross-section of the AIC load for full requirements products at this time. (ICEA Objections at 17)

ICEA claims one benefit to its proposed approach is that it should be fairly simple to implement. The portion of the load to be supplied by full requirements products will be a fixed percentage share of the entire actual hourly load requirement, and therefore it will include full requirements products that are structurally similar to those solicited elsewhere, in which each full requirements product tranche will supply a fixed percentage of the entire bundled service load requirement (for eligible retail customers) in every hour. Meanwhile, ICEA says the IPA's proposed percentage hedge targets for the block energy products will be preserved (but they will be applied to the 70% block-and-spot cross-section as opposed to the entire forecasted load). ICEA claims its proposed approach does not involve the concerns associated with the alternative integration approach which the IPA considered and rejected. ICEA says the IPA considered an approach in which the load would not be split into two cross-sections as proposed by ICEA, and instead the full requirements products would only cover the residual load (the difference between the load quantities and the existing block product quantities), but they would require the full requirements suppliers to bear all of the load risk, which the IPA cautioned would create a great deal of uncertainty in the determination of the reasonableness of the full requirements product pricing. ICEA argues that by splitting the load as it proposes, full requirements product suppliers will not be required to bear the entire load risk while only serving the "residual load," the prices of the full requirements products will be reduced, and the prices more easily can be compared to expectations about the market costs of various components of the full requirements supply obligation as of the times of the full requirements product solicitations. (ICEA Objections at 17-18)

ICEA insists its proposal should not be difficult to implement. ICEA claims much of the incremental implementation work, such as the publicity, bidder qualification, bidder information dissemination, and RFP administration, will be minimized because the same tasks will be performed in the context of the mid-April block energy product

RFP. ICEA also claims the development of a supplier contract for the full requirements product should be relatively straightforward, because there already are many existing supplier contracts for full requirements products that could be refined as necessary for the development of a contract for ComEd's full requirements product. (ICEA Objections at 18)

According to ICEA, the use of full requirements products in the Plan would provide the IPA and the Commission with an opportunity to better assess the transparency and reduced distortions created by the full requirements approach. Rather than subjecting customers to a variable rate, ICEA says this approach allows a pro-rata share of the costs associated with spot purchases to pass through to the respective full requirements suppliers. ICEA encourages the Commission to modify the Plan to include the use of full requirements products as ICEA suggests, in order to gauge how this approach will work and potentially expand the use of full requirements products in future procurements. (ICEA Objections at 18-19)

In its Response to Objections, ICEA asserts AIC's objections do not provide any valid basis to reject ICEA's recommendation that the Plan be revised to require the IPA to incorporate the use of fixed-price, full requirements products into its current supply portfolio. ICEA says full requirements are supported by both retail and wholesale suppliers, as reflected in the Objections of both RESA and Exelon. (ICEA Response at 1-2)

AIC indicates that a determination should be made as to whether load following products, including full requirements and partial requirements, are allowed under the IPA Act. ICEA says AIC correctly notes that the legality of full requirements falling within the IPA Act was litigated, but not determined, during evaluation of the 2012 IPA Plan. ICEA claims no party in this case has specifically identified any issue with full requirements falling within the statutory authority of the IPA as "standard wholesale products." (ICEA Response at 2)

ICEA claims it has articulated in past procurement plan comments and Commission proceedings that the standard product procurement in the IPA Act was meant to be illustrative and not exhaustive. By combining various products identified in the statute, ICEA asserts one can achieve a full requirements product, and the IPA has the discretion to procure those products in combination. ICEA contends that a full requirements product such as that advocated by ICEA and discussed in the NorthBridge report accompanying ICEA's Objections falls within the permissible products under the IPA Act. ICEA notes Section 16-111.5(b)(3)(iv) of the PUA provides for contracts executed for products "separately or in combination… including but not limited to." According to ICEA, 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, ICEA maintains one can achieve a full requirements product. (ICEA Response at 2-3)

ICEA claims the IPA has taken a significant step toward providing clarity in this matter. ICEA's interpretation has been borne out by the Plan. ICEA asserts as articulated by the IPA, the definition of “standard product” may include wholesale load-following products (including full requirements or partial requirements) as long as the procurement is standardized such that bids may be judged solely on price. ICEA says although AIC indicates that an assessment of the legality of full requirements must be made, it does not provide any basis from which to conclude that a full requirements product is anything other than an authorized product under the IPA Act. (ICEA Response at 3-4)

ICEA believes AIC’s claim that the insignificant amount of load proposed to be hedged in the Plan needs to be contrasted against the effort and cost associated with implementing a full requirements procurement is misplaced. Given the oversubscription in AIC, ICEA’s proposal does not include carving out a cross-section of the AIC load for full requirements. It is unclear to ICEA why AIC is concerned about ICEA’s proposal for full requirements in this year’s Plan at all. Regardless, ICEA argues its proposal should not be difficult to implement. According to ICEA, much of the incremental implementation work, such as the publicity, bidder qualification, bidder information dissemination, and RFP administration, will be minimized because the same tasks will be performed in the context of the mid-April block energy product RFP. ICEA maintains the development of a supplier contract for the full requirements product should be relatively straightforward, because there already are many existing supplier contracts for full requirements products that could be refined as necessary for the development of a contract for ComEd’s full requirements product. ICEA believes the fact that there is a relatively small amount of load based on current forecasts is not a reason to reject a blending of full requirements into the Plan; rather, ICEA says it provides the Commission with an ideal opportunity to dip the proverbial regulatory toes into the water of full requirements. (ICEA Response at 4)

In ICEA's view, AIC's suggestion that the load following product would need to be further defined, while true, is not a barrier to implementation. ICEA asserts its proposal already contains certain details regarding the product, in that the full requirements product for energy would be structurally similar to those solicited elsewhere, with full requirements suppliers bearing all of the risk, including for weather and switching. ICEA maintains that full requirements are used extensively throughout PJM, and any details regarding schedules and settlement should be relatively easy to replicate from other utilities in PJM that use full requirements. ICEA believes none of what AIC points to as potential issues is, in reality, an impediment to implementation of a full requirements product in this Plan. (ICEA Response at 4-5)

ICEA claims AIC's objection that any risk premiums would need to be estimated and compared against any perceived benefit of the product has already occurred. ICEA has provided an analysis from NorthBridge regarding the benefits and costs associated with full requirements, in addition to providing specific and detailed criticisms of the flawed analysis offered by the IPA in its Plan. (ICEA Response at 5)

Although ICEA recognizes the fact that there may be some cost to suppliers bearing those risks that will factor into bids, ICEA 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. ICEA argues the benefits of having prices known and measurable are obvious when assessing recent variability in pricing. ICEA says ComEd's most recent PEA filing for November 2013 shows a deferral of over $27 million in PEA related costs in a single month that will be deferred, based on ComEd's commitment to limit the PEA to no more than 0.50 cents/kWh. ICEA says those deferred charges are not "free." ICEA insists customers will have to pay them back over time, with carrying charges. ICEA claims the PEA distorts those price signals to customers, as does the block-and-spot approach, which ICEA says is similarly unknown to customers in advance. Since neither the electricity costs incurred through spot transactions incurred via the block-and-spot approach nor the deferred costs held in the deferred balances are included in the PTC, ICEA argues default service customers are unable to properly evaluate the true comparison in price offerings between the ARES and the utility default service price. ICEA contends full requirements, in contrast, provides a known, open and transparent price for customers for the entire term of the procurement. (ICEA Response at 5-6)

According to ICEA, the fact that a litigated review regarding the assumptions and conclusions must be made is not justification for rejecting full requirements out of hand, as AIC suggests. ICEA says an independent assessment of those assumptions and conclusions should be able to occur relatively easily, and in a straightforward manner, in this docket. ICEA believes the fact that there may be time and effort required to do so does not mean that the parties should be content with the status quo, and ignore recommendations that carry the possibility of even greater success in the future. ICEA says the goal of the statutorily mandated IPA review process each year, and the requirement for filing a new plan each year, is that the process can be continually improved upon. ICEA alleges that narrow thinking does not address the varied and substantial potential benefits that full requirements can provide, including the following:

1. Avoids inevitable volatility for customers due to forecast for which tranches were established not matching with actual needs, requiring monthly spot purchases/sales;
2. Protects against risk of customer migration; and
3. Bidders have superior expertise in managing portfolios.

(ICEA Response at 6)

ICEA claims that contrary to CUB's assertions, full requirements products are authorized under the law. CUB cites to ComEd arguments in Docket No. 11-0660 as evidence of full requirements products falling outside the definition of a "standard wholesale product" under the IPA Act. ICEA says citation to a Commission Order that merely summarizes another party's position in a previous docket is not evidence. ICEA also says its proposal is not identical to the procurement that was held prior to the adoption of the IPA Act. ICEA asserts the procurement referenced by CUB came in the form of a descending clock reverse auction to procure all of the electric power needs of

ComEd and AIC for a 3-year period, which is a different structure than ICEA is recommending. ICEA claims it has not recommended any change in the structure of the competitive procurements that have occurred under the IPA; ICEA has recommended what it believes is a superior product for small portion (30%) of the total power needs for ComEd. (ICEA Reply at 2)

According to ICEA, the initial auction process came immediately after a period in which Illinois customers had enjoyed over a decade of artificially reduced, suppressed, and frozen rates, thereby exposing customers to true market prices for electric power and energy at a time that saw some of the highest wholesale market rates over the past 20 years. ICEA notes under the IPA Act, the Illinois General Assembly did not issue a mandate under the IPA Act that Illinois consumers should pay anything other than market prices for electric power and energy and specifically directed the continued use of a competitive procurement process. ICEA says the General Assembly simply established the IPA as an independent third-party to recommend the structure and products, and to retain overall management of the procurement process, subject to Commission approval. (ICEA Reply at 2-3)

ICEA notes Staff supports ICEA's view that the law, while not specifically addressing full requirements products, permits the use of full requirements products through the statutory language that allows for products singly, or in combination. According to ICEA, when looking at the letter of the law, one cannot conclude that full requirements products are prohibited. (ICEA Reply at 3)

In ICEA's view, the question of whether or not full requirements products should be incorporated into the current Plan is not a legal question. ICEA agrees with the IPA that whether to procure a full requirements product is a policy question to be resolved by the Commission. (ICEA Reply at 3-4)

ICEA says both CUB and the IPA recognize that trends in customer migration to and away from utilities can be magnified if there is lag in reflecting the utility's energy costs in customer rates and volume changes resulting from these pricing differences may results in additional price risks for utility customers. ICEA contends that is precisely what happens with a PEA mechanism which changes each month and, to the extent that the voluntary cap imposed by ComEd is hit, with deferred balances that are carried over month after month. ICEA cannot understand why CUB chooses to favor the use of energy efficiency and demand response over full requirements products to somehow manage the volatility or risk. ICEA says CUB indicates that managing the risk associated with supply prices and load size is the reason a third-party agency like the IPA was created. ICEA asserts the existence of the IPA in and of itself does not insulate utility bundled customers from risk, just as demand response and energy efficiency measures cannot correct for potential significant differences in utility load that was forecasted due to customer migration or any other variable. (ICEA Reply at 4)

ICEA says the AG also admits that there is risk of customers migrating back to utility bundled service, leading to insufficient spot-and-block purchases. ICEA claims the AG even considers the possibility that adjustments to the IPA's analysis of full requirements products are warranted, and that the incorporation of full requirements products would result in a lower premium for full requirements products than the IPA claims. ICEA says the AG suggests that the potential cost of developing a price benchmark should halt any consideration of the use of full requirements products. ICEA maintains full requirements products are used extensively in competitive procurements for utility bundled load in a number of states. ICEA also says development of a benchmark should not be difficult or give rise to a serious roadblock to implementation of a full requirements product. ICEA claims there are numerous consultants and procurement experts that perform a similar role to the IPA that have and do develop certain benchmarks or similar mechanisms to guide the procurement process. (ICEA Reply at 4-5)

ICEA states while continuing to voice their opposition to the use of full requirements products, neither the IPA nor AIC provide any substantive criticism of the NorthBridge Report that accompanied ICEA's Objections and helped inform ICEA's recommendations. ICEA says they largely restate previous objections to which ICEA has already responded. ICEA asserts that while the cost to wholesale suppliers bearing all of the risks will factor into bids, 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, significant customer migration, and potential prices changes in the market cannot be known. ICEA says the IPA makes light of the significance of the PEA, arguing that the harmful effects of excessive price premiums/markups and price instability on bundled customers are currently minimized and bounded, respectively. ICEA notes ComEd's capping of the PEA is voluntary, which means that the current limitations could change over time. ICEA also says although there is currently a cap, dollars deferred will ultimately have to be paid by customers. ICEA contends the IPA misses the point that moving cost recovery from the procured product to the PEA effectively results in a bait-and-switch approach of forward prices for retail customers because the PEA can change up to $10/MWh from month to month (a $5/MWh charge to a $5/MWh credit), without warning. ICEA says the result is a "range to compare," rather than a "price to compare." (ICEA Reply at 5-6)

The IPA suggests that if bundled customers are not happy with excessive perceived risk, that customer is free to choose a fixed price offer from an ARES. ICEA asserts that while true, the availability of different products in the competitive market is not a basis to reject a product offering that minimizes risk to bundled customers. ICEA believes it should not be an accepted practice of the IPA or the Commission to knowingly test the bounds of bundled customers' risk tolerance, in the face of substantial uncertainty regarding the delta between forecasted versus actual load as well as any future electric market price changes. Although ICEA appreciates and accepts the IPA's willingness to participate in any process to make changes to how the utility price-to-compare is conveyed to customers, ICEA claims the nature of the PEA will not change with different customer communications and therefore the fundamental risks underlying the block-and-spot approach will not change. (ICEA Reply at 6)

ICEA contends the IPA's argument that no party supporting full requirements products argued that such a procurement event would guarantee customer savings is without merit. ICEA says the IPA Act does not require that products must guarantee customer savings. ICEA claims this is obvious from the fact that the IPA's historical block-and-spot approach has not guaranteed customer savings. ICEA says that is the crux of the debate and there are no guarantees. ICEA claims the very inability to provide a guarantee under the current block-and-spot approach is precisely the reason to incorporate the use of full requirements products. ICEA asserts while there are no guarantees that customers will experience savings over the current approach, there is at least a guaranteed fixed price for ComEd bundled customers under the ICEA recommendation, which the IPA cannot offer under the block-and-spot approach. According to ICEA, for all of its criticisms of incorporating full requirements products, the IPA does not challenge the NorthBridge Report in any material respect. (ICEA Reply at 9-7)

ICEA says the only party to look at the substance of the NorthBridge Report is Staff, which concluded that it is in complete agreement with the findings from the NorthBridge Report. ICEA says Staff agreed with some of the same criticisms of the IPA analysis as were identified and discussed in the NorthBridge Report. While ultimately Staff did not take a position regarding the use of full requirements products, ICEA says Staff found that when considering the propriety of incorporating full requirements products into the current portfolio, it is most useful to look at data from where block and spot and full requirements products are implemented simultaneously, as the NorthBridge Report does. ICEA claims that is as close to a guarantee as anyone can or has provided in this Docket. (ICEA Reply at 7)

ICEA notes WOW sought clarification regarding the full requirements product being recommended by ICEA. Specifically, WOW indicated that it was unclear whether the full requirements product would include renewable energy resources. WOW articulated that the fixed price full requirements product should not include the procurement of renewable energy resources. ICEA appreciates the opportunity to clarify that the fixed price full requirements product ICEA recommends is designed to replace the current base energy procurement. ICEA says it was not intended to eliminate or replace the separate renewable energy procurements for the utilities that has been historically conducted by the IPA; ICEA concurs with WOW that there are a number of reasons to keep the renewable energy procurement separate from the base energy competitive procurement, and does not recommend altering the current process for renewable energy procurement. (ICEA Reply at 7-8)

In its Reply Brief on Exceptions, ICEA argues that the IPA's replacement language should be rejected. (ICEA RBOE at 2-7)

2. RESA's Position

RESA notes that the IPA proposes, in the 2014 Procurement Plan, a three-year ladder approach: the IPA will procure 25% of the forecast energy need for the third year

(June 2016 through May 2017), 50% for the second year (June 2015 through May 2016), and 75% for November to May of the first year (November 2014 through May 2015) through the purchase of on-peak and off-peak blocks of energy. However, the IPA will be fully hedged for June through October of the first year (June 2014 through October 2014). Because the blocks of energy will never exactly match the usage of default service customers, the electric utilities will be buying or selling energy, as necessary, in the spot market. RESA refers to the IPA's procurement approach as the block-and-spot approach. (RESA Objections at 2)

In support of its proposed procurement strategy, RESA says the IPA states that it believes that its continued use of a three-year laddered approach is the most prudent and most likely to produce its statutorily mandated objective to develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. (RESA Objections at 3)

RESA believes the IPA failed to address multiple procurement events in the 2014 Procurement Plan and advocates continued use of the three-year laddered approach. RESA has repeatedly recommended over the course of various years' IPA plans that the Commission require that the IPA use multiple procurement events in order to more closely reflect the market price of the supply purchased. RESA says the reasons expressed previously by RESA for multiple procurement events are valid for the current, 2014 Draft Plan. RESA states that because this multiple procurement approach appears unlikely to be adopted by either the IPA or the Commission, RESA will not be recommending the use of multiple procurement events at this time. However, RESA says it cannot support continued limitation of the procurement plans to use of the block-and-spot method using the three-year laddered approach. (RESA Objections at 3)

Instead, RESA supports the proposal of ICEA that the IPA incorporate the use of fixed-priced, full requirements ("FPFR") products into the current supply portfolio. Specifically, RESA supports ICEA's proposal to refine the 2014 Procurement Plan so that 30% of the bundled service load of ComEd's eligible retail customers will be supplied through FPFR products during the June 2014-May 2015 period, leaving the possibility for further FPFR product procurements to be included in future IPA Plans. (RESA Objections at 3-4)

In RESA's view, the IPA's recommended electric supply procurement strategy, block and spot, does not allow Illinois retail customers to see the true and transparent price for electricity which they will ultimately pay due to the unforeseeable costs captured in the PEA. According to RESA, the transactional costs which customers must pay monthly through the PEA distort the price comparison between ARES competitive pricing and the price-to-compare tariff rate for electricity supply due to the IPA's block-and-spot procurement strategy. (RESA Objections at 4)

RESA argues that under the block-and-spot strategy, customers will make their retail electricity purchase decisions based upon the published utility price-to-compare, which will be the known price related to the block energy purchases, and will not include the spot purchases that must be made at a later date by the utilities to fulfill their wholesale electricity purchase needs for their retail customers. RESA claims this means that customers will only see part of their future retail electricity costs reflected in utility prices, but will pay a larger number as the utility spot purchase costs get layered on at a later date. RESA asserts this distorts the market and makes utility bundled service appear to be more economical than it really is. RESA says the quantity level and price of future utility spot purchases are necessarily unknown and not capable of being forecasted until the time when they are required because spot purchases are make-up amounts above the block purchases, and are a result of uncertain retail customer demand and usage. In RESA's view, the laddered block-and-spot procurement strategy suggested by the IPA provides an opaque retail electricity pricing structure that cannot be fairly compared to the competitive retail electric prices provided in the competitive market. RESA contends that under the IPA's recommended block-and-spot procurement strategy, the utility price-to-compare is not. RESA says this distortion will make utility bundled service appear to be more economical than it really is, which chills energy efficiency and demand-side management investment and increases associated investment pay-back periods. (RESA Objections at 4-5)

RESA asserts recent history demonstrates that the additional costs for purchasing electricity under the IPA's block-and-spot strategy have outweighed any revenues collected for selling power back into the market through that block-and-spot strategy. RESA believes a procurement approach like the FPFR approach that is reflective of all of the power and energy necessary to serve a customer, along with its corresponding prices, provides the best environment for sustainable, robust retail competition. (RESA Objections at 5)

While the IPA's 2014 Procurement Plan contained an assessment of the possibility of including FPFR products in the supply portfolio for eligible retail customers and rejects that approach, RESA claims that rejection is based on an incomplete and inaccurate assessment of the use of a full requirements procurement approach. RESA says a critique of IPA's analysis of FPFR products is contained in a report prepared by NorthBridge, which was attached as Appendix A to ICEA's Comments. RESA also says Staff, in its Comments on the 2014 Draft Plan, found the IPA's analysis of the use of FPFR products to be deficient. RESA notes while the IPA revised some of the language in the 2014 Procurement Plan regarding its analysis of FPFR products from the language contained in the 2014 Draft Plan, it did not change its model, assumptions, nor analysis. (RESA Objections at 5-6)

RESA argues that in contrast to the IPA's analysis, NorthBridge presented a quantitative analysis based on actual market data from a region in which the block-and-spot approach and the FPFR product approach had been implemented simultaneously. RESA says NorthBridge's analysis showed that the compensation that FPFR product suppliers require to directly bear costs and risks that would otherwise be borne by customers is reasonable. According to RESA, NorthBridge's analysis indicated that, in comparison to the FPFR product approach, the increases in risk borne by residential customers under the block-and-spot approach are not balanced by a proportionate decrease in the expected default service level. Consequently, NorthBridge recommended that FPFR products be included in the 2014 IPA Procurement Plan to protect customers from the adverse risks of the block-and-spot approach and to allow gaining more information about FPFR products in the context of the Illinois electricity markets. (RESA Objections at 6)

RESA agrees with ICEA that the use of FPFR products in the IPA's 2014 Procurement Plan would provide the IPA and the Commission with the opportunity to better assess the transparency and reduced distortions resulting from the FPFR approach. RESA encourages the Commission to require the use of FPFR products in the procurement plan approved by the Commission in this proceeding in order to gauge how this approach will work and, if successful, expand the use of FPFR products in future procurements. (RESA Objections at 6)

RESA claims one benefit of ICEA's proposed approach is that it should be fairly simple to implement. RESA also claims ICEA's proposed approach does not involve the concerns associated with the alternative integration approach which the IPA considered and rejected in the 2014 Procurement Plan. According to RESA, the development of a supplier contract for the FPFR product should be relatively straightforward because there already are many existing supplier contracts for FPFR products that could be refined as necessary for the development of a contract for ComEd's FPFR product. Finally, RESA says the use of FPFR products would provide the IPA and the Commission with an opportunity to better assess the transparency and reduced distortions created by the FPFR approach. (RESA Objections at 7)

RESA supports and endorses ICEA's Verified Response to Objections in this proceeding which it claims rebuts all of AIC's concerns regarding fixed-priced, full requirements products. RESA continues to recommend that the Commission accept ICEA's specific full requirements proposal and incorporate that proposal in the 2014 Procurement Plan. (RESA Response at 2, Reply at 3)

RESA notes ICEA's proposal was opposed by AIC, the AG, CUB, and the IPA. RESA claims AIC basically repeated arguments made in its Objections that RESA says were rebutted by ICEA in its Verified Response. RESA says the IPA, the AG, and CUB relied on the IPA's analysis, contained in the 2014 Procurement Plan, of full requirements products. In RESA's view, that analysis was demonstrated to be flawed by ICEA in its Objections, including the NorthBridge Report, attached to those Objections. (RESA Reply at 2)

In its Reply Brief on Exceptions, RESA says the reasoning in the Proposed Order, in part, for not recommending the incorporation of Full Requirements products for ComEd into the 2014 Procurement Plan appears to be that some types of full requirement products may not qualify as standard products required under the IPA Act. (RESA RBOE at 2-3) While the Proposed Order did note that some types of full requirements products may not qualify as standard products required under the IPA Act, RESA's suggestion that this was part of the reason for rejecting full requirements products in the 2014 Procurement Plan is wrong. The Commission's basis for rejecting full requirements products at this time is in no way related to the fact that some such products do not qualify as standard products under the IPA Act.

3. Exelon's Position

Exelon says it has long advocated that the IPA transition from total reliance upon a wholesale "block-and-spot" procurement approach to one that relies upon the use of fixed-price, full requirements contracts. However, to date, the IPA has failed to include such products in its procurement approach. (Exelon Objections at 3)

According to Exelon, the IPA Act was created at a time in which there was little, if any, activity within the residential and small commercial classes. Exelon says that is no longer the case due in large measure to the number of communities participating in municipal aggregation, which has taken off within the past two years. Although a block-and-spot procurement strategy may have worked in the past, Exelon claims Illinois sits at the precipice of experiencing potentially dramatic shifts in utility-supplied load as those initial contracts roll off, and communities decide how best to meet the needs of the municipality and its residents and businesses going forward. Exelon notes the IPA did include a potential second September energy procurement in the Plan, which is designed to hedge for some movement. In Exelon's view, an optional mid-year procurement is an inadequate substitute for active management portfolio management that is part of a full requirements product, which includes taking on the risks associated with potential large, and sudden, swings that may occur in utility supply obligations. (Exelon Objections at 3-4)

In the Plan, the IPA does include an assessment of a full requirements approach and compares such an approach with its proposed continued use of a block-and-spot approach. Exelon claims the discussion in the Plan fails to properly recognize the additional costs, risks, and flaws inherent in its proposed procurement approach, particularly in the current environment. (Exelon Objections at 4)

In order to procure supply required to meet the needs of eligible retail customers, as defined within the Act, Exelon believes the Plan should be modified to use full requirements, load following products. Exelon says the IPA is given discretion to procure products individually, or in combination. Exelon believes the Commission 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 using full requirements contracts. (Id.)

According to Exelon, the benefits offered by a full requirements approach have never been greater than this upcoming procurement cycle due to the possibility that the number of utilities' bundled customers and underlying load will be changed, potentially dramatically, during that time. (Id.)

Exelon argues that a full requirements approach will best meet the requirements of Illinois law. Exelon asserts 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. Exelon claims 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 retail electric suppliers (“RESs”). Exelon contends as risks and costs to ComEd and AIC 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. (Exelon Objections at 5)

Exelon asserts that an IPA plan relying on full requirements products provides a proper balance by obtaining the most competitive prices for consumers, while appropriately placing risks such as volume risk on wholesale suppliers. Exelon says support for this notion comes from an important study on Pennsylvania’s energy future by Dr. Tierney, a nationally recognized energy policy expert, former Assistant Secretary for Policy at the U.S. Department of Energy, and former Commissioner at the Massachusetts Department of Public Utilities. According to Exelon, Dr. Tierney documents that, through competitive full requirements procurements, wholesale suppliers bring many benefits because of their abilities and skills. (Exelon Objections at 5-6)

According to Exelon, a diverse pool of wholesale full requirements product suppliers provide the most cost-effective method of management for eligible retail customers. Under full requirements product procurements Exelon says 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. Exelon asserts 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. Exelon also claims 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. Exelon contends 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. Exelon says 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. (Exelon Objections at 6)

Exelon alleges a wholesale supplier’s greater expertise in daily, active portfolio management 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. Exelon claims 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 Exelon to provide significant competitive benefits over a smaller, less sophisticated market participant. Exelon also says 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. (Exelon Objections at 6-7)

Exelon supports the recommendation contained in the Comments and the Objections of ICEA that recommend a supply approach based on the procurement of fixed-price, full requirements products as a superior approach based upon the current market conditions and to better protect customers from risks. Exelon believes, given the comprehensive analysis that is part of ICEA's Comments on the benefits of fixed-price, full requirements products and the fact that these benefits are widely recognized in other restructured jurisdictions, such products should be included in the IPA Plan as specified in ICEA's proposal. (Exelon Objections at 7)

To the extent that full requirements are not incorporated in the Plan, Exelon suggests the IPA should not procure energy beyond May 2016. Exelon claims that to do otherwise necessarily limits the flexibility for future plans, thereby preventing meaningful opportunity to re-visit alternative procurement options, such as full requirements, until 2018. Exelon asserts that limiting energy procurements within the Plan to the June 2014-May 2016 period will not harm the retail market, nor is it likely to decrease bidder interest and participation in the energy and capacity auctions. Exelon says at the same time, it leaves the IPA and the Commission the ability to consider all procurement options for the period beginning June 2016. (Exelon Objections at 7-8)

In its Reply Brief on Exceptions, Exelon clarifies that it did not intend to restrict its recommendation regarding limiting future procurements only to ComEd. ExGen encourages the Commission to limit energy supply procurements for the Plan (including AIC) to the period prior to May 2016. Exelon says a Commission Order authorizing or preventing the Ameren procurement for June 2016-May 2017 would not have a significant impact on the IPA portfolio. Exelon claims there would be no harm the retail market, or likely decrease in bidder interest and participation in the energy and capacity auctions. Exelon maintains there is no harm in limiting procurements to the June 2014-May 2016 period. (Exelon RBOE at 2-3)

According to Exelon, AIC provides four different considerations regarding full requirements: (1) whether load following products (including full requirements and partial requirements) are allowed under the IPA Act. This matter would appear to relate primarily to the interpretation of the definition of "standard wholesale products" in the IPA Act. (2) The insignificant amount of load proposed to be hedged in the Plan needs to be contrasted against the effort and cost associated with implementing a full requirements procurement. (3) The load following product would need to be further defined. (4) Any risk premiums associated with full requirements products would need to be estimated and compared against any perceived benefit received of the products.

(Exelon Response at 1-2, citing AIC Objections at 6-8) In Exelon's view, none of AIC's criticisms of full requirements warrants rejecting full requirements.

Exelon claims full requirements are permitted under the law. Exelon states under the IPA Act, the standard product definition is broad, providing examples, but not an exhaustive list. Exelon says the various products identified in the statute can be combined to become a full requirements product, and approving products in combination is within the purview of the IPA. Exelon states as identified in the Section 16-111.5(b)(3)(iv) of the PUA, contracts may be executed for products "separately **or in combination… including but not limited to**" (emphasis added). Exelon also says as noted in the NorthBridge Report, the fact that the full requirements product approach has become by far the most prevalent form of default service supply procurement for smaller customers in restructured jurisdictions provides further support for full requirements being a "standard" wholesale product. Exelon notes, no party, including AIC, has actually challenged a legal basis for full requirements. (Exelon Response at 2)

Exelon argues that contrary to AIC's concerns, full requirements should require little implementation effort, with regard to both contracting and product development. Exelon claims it should not be difficult to further define the specific full requirements product. Exelon maintains full requirements are used in a number of jurisdictions. Similarly, as ICEA pointed out in its Objections, Exelon asserts much of the incremental implementation work, such as the publicity, bidder qualification, bidder information dissemination, and RFP administration, will be minimized because the same tasks will be performed in the context of the mid-April block energy product RFP. Exelon also asserts the development of a supplier contract for the full requirements product should be relatively straightforward, because there already are many existing supplier contracts for full requirements products that could be refined as necessary for the development of a contract. (Exelon Response at 2-3)

With regard to risk premiums, Exelon says while there may be some cost to suppliers bearing those risks that will factor into bids, those full supply costs are known and measurable at the time of the procurement results. Exelon also claims those risks are being borne by winning suppliers, who manage portfolios on a daily basis and therefore understand and can manage those risks. Exelon says those risks exist without full requirements; the difference is that the risks are being borne by residential and small commercial customers who may not understand, and who are without the ability to manage those risks. (Exelon Response at 3)

In its Reply to Responses, Exelon says the IPA, CUB, the AG, and AIC do not make any new substantive arguments providing a basis for rejecting full requirements. According to Exelon, for the most part they merely recite arguments made previously in this case and addressed in Objections, or Responses To Objections, of Exelon, or ICEA. Exelon believes no Responses Objections to the IPA Plan provide any reason for rejecting full requirements, or other improvements offered by Exelon. Therefore, Exelon recommends that the IPA's Final Plan be modified in order to reflect the improvements to the procurement process as set forth in Exelon's Objections and its Response to Objections. (Exelon Reply at 1-2)

4. AIC's Position

AIC notes the Plan states that the definition of "standard product" may be broad enough to include wholesale load-following products (including full requirements or partial requirements) as long as the procurement is standardized such that bids may be judged solely on price. The Plan continues by stating that the legal question regarding the IPA's authority to procure full requirements products was litigated in Docket No. 11-0660, but the Commission did not Order on the matter at that time. The Plan continues by stating that the IPA anticipates the matter will be re-litigated in this docket to the extent that ICEA's proposal for a full requirements procurement is litigated as well. (AIC Objections at 6)

AIC notes that the Plan proposes a very limited quantity of energy procurements for AIC eligible retail load and proposes no procurement of capacity and no procurement of renewable resources. Given the limited procurement associated with the Plan and the uncertainty of load supplied to eligible retail customers, AIC believes the timing for a debate regarding the IPA's authority to procure full requirements and a subsequent decision by the Commission would be better suited for future Plans. (AIC Objections at 6)

AIC states if this issue is to be determined within this proceeding, numerous factors would need to be considered. AIC suggests a determination should be made as to whether load following products (including full requirements and partial requirements) are allowed under the IPA Act. AIC says this matter would appear to relate primarily to the interpretation of the definition of "standard wholesale products" in the IPA Act. (AIC Objections at 6-7, Response at 1-2)

In AIC's view, the insignificant amount of load proposed to be hedged in the Plan needs to be contrasted against the effort and cost associated with implementing a full requirements procurement. AIC notes that the Plan proposes the procurement of energy hedges pertaining to AIC for only three months of the prompt year, with the average hedge quantity for these monthly blocks being less than 100 MW. AIC says for these three months, only one month (July 2014) includes a proposed procurement for both on peak and off peak hedges. In AIC's view, the limited size of the proposed energy procurement does not appear to justify a determination in this Plan as to whether load following products are allowed under the law. According to AIC, nor does it appear to justify the development of a contract and the implementation of a procurement event for a full requirements product. (AIC Objections at 7, Response at 1-2)

AIC also believes the load following product would need to be further defined. AIC says a determination would need to be made as to whether the product includes energy only or includes energy plus capacity or includes energy, capacity and an acceptable form of renewable resources (e.g., renewable energy credits). AIC also claims the product should define whether the buyer or seller is responsible for weather and switching risk and further, which party would act as the market participant responsible for administering the contract within MISO. In AIC's view, such administration could prove difficult and costly since MISO schedules are due within several days of the operating day and final meter settlement is not available until 105 days after the operating day (this issue may require a preliminary and final settlement component of the contract further complicating the matter). If the contract is not intended to settle within MISO and instead is intended as a financial product, AIC says the ramifications as to whether such a contract would have reporting requirements associated with Dodd Frank would need to be considered, and if so, who is the reporting party. (AIC Objections at 7, Response at 2-3)

AIC says the terms of any load following transaction and the administrative responsibilities of the buyer and seller would need to be further refined and memorialized in a standardized contract and then articulated through a separate procurement event along with the establishment of separate procurement benchmarks. In AIC's view, this is not a simple task as some parties suggest and would further add to administrative costs associated with the procurement process for the upcoming plan year. According to AIC, the limited scope of the AIC energy procurements proposed by the IPA strongly suggest that the costs of pursuing a load following procurement at this time would receive little or no reciprocating benefit; such costs therefore become unnecessary. AIC continues to recommend the proposals for load following procurements be rejected within the context of the Plan, whereas the Commission may wish to subsequently revisit the matter in future Plans. However, if the Commission desires to pursue load following procurements for ComEd in the Plan, AIC requests that it be excluded in light of the minimal procurement quantities proposed for AIC eligible retail customers. (AIC Reply at 1-2)

AIC also asserts any risk premiums associated with full requirements products would need to estimated and compared against any perceived benefit received of the products. AIC says while the Plan has provided some analysis in this regard, a litigated review and debate regarding the assumptions and conclusions would likely prove time consuming, contentious and costly. (AIC Objections at 7-8, Reply at 1)

AIC recommends the load following debate (including full and partial requirements products) and any subsequent decision by the Commission be delayed until future Plans. Considering the matter now would be a time consuming and costly effort which does not appear to AIC to be justified based on the limited quantity and type of hedging proposed in the Plan. (AIC Objections at 8, Response at 3)

Exelon states the use of a full requirements approach will best meet the requirements of Illinois law, limit risk to the customers by shifting them to the wholesale full requirements suppliers and provide the most cost effective method of management for eligible retail customers. AIC disagrees, as it notes that the Plan proposes a very limited quantity of energy procurements for AIC eligible retail load and proposes no procurement of capacity and no procurement of renewable resources (on the contrary certain renewable contracts are proposed to be proportionally curtailed). Given the limited procurement associated with the Plan and the uncertainty of load supplied to eligible retail customers, AIC believes the timing for a debate regarding the IPA's authority to procure full requirements and a subsequent decision by the Commission is better suited for future Plans. (AIC Response at 1)

5. The IPA's Position

The IPA notes ICEA, RESA, and Exelon recommend that the IPA procure a full requirements energy product in addition to scaled back block purchases. ICEA presents an alternative model for determining the costs associated with full requirements, while ICEA, RESA, and Exelon provide additional justifications for procuring a "fixed price full requirements" energy procurement. (IPA Response at 3-4)

The IPA notes that one critical point that ICEA, RESA, and Exelon did not dispute (including in ICEA's alternative model) is the conclusion in the IPA's analysis that there is a price premium in a full requirements energy product. Although ICEA, RESA, and Exelon provided reasons that the premium may be worthwhile, the IPA says none of the parties argued that the addition of a full requirements procurement would guarantee customer savings. The IPA also notes that ICEA, RESA, and Exelon did not make policy arguments, such as: (1) full requirements was an appropriate product for all bundled customers, or (2) default service should "compete" in the market by offering the same product that ARES offer. (IPA Response at 4)

In its Reply Brief on Exceptions, the IPA disputes the arguments of ICEA and Exelon that the NorthBridge Report is unrebutted because no party (except a tentatively supportive Staff) analyzed the document, and therefore the NorthBridge Report's conclusions should be adopted by default. The IPA says it has reviewed the NorthBridge Report and the IPA has consistently described its concerns with ordering a Full Requirements procurement at this time. In the IPA's view, the NorthBridge Report does not provide sufficient bases to convince the IPA to recommend that the Commission approve a Full Requirements procurement at this time. (IPA RBOE at 2)

The IPA says as far as it could tell, the NorthBridge Report in ICEA's Objections (filed October 7, 2013) was unchanged since ICEA provided the report in timely filed Comments on the draft Procurement Plan for comment on September 16, 2013. In the Procurement Plan that the IPA filed on September 30, 2013, the IPA indicates it updated its discussion of Full Requirements in Sections 6.7, 6.7.1, 6.7.2, and 6.7.2.1 of the Procurement Plan filed on September 30 to respond to some of the criticisms from the NorthBridge Report, updates that the IPA says ICEA, RESA, and Exelon have failed to address. (IPA RBOE at 2-3) The IPA insists it did have sufficient time to review the NorthBridge Report, and modified the Procurement Plan in response to some of the criticisms. The IPA believes it demonstrated that the NorthBridge Report (like the IPA's analysis) showed a premium for a Full Requirements procurement. (IPA RBOE at 4)

The IPA believes ultimately the question of whether to procure a full requirements product is a policy question to be resolved by the Commission. The IPA says on one hand, ICEA, Exelon, and RESA are correct that a fixed-price full requirements product would provide greater price stability for bundled customers than the current (and proposed) system of procurement of fixed price energy blocks and accounting adjustments for imbalances through the utility's Purchased Electricity Adjustment. On the other hand, the IPA says the PEA represents cost adjustments without price premiums or profit markups and is currently voluntarily capped by ComEd, so the harmful effects of excessive price premiums/markups and price instability on bundled customers are currently minimized and bounded, respectively. Also, the IPA notes that if the bundled rate presents excessive perceived risk for a bundled service customer, the customer may easily choose a fixed price full requirements offer from an ARES. The IPA says many ARES in the market currently offer fixed price full requirements products that can provide price insurance at competitive prices, even when the nominal price-to-compare is lower. (IPA Response at 4-5)

According to the IPA, all of these open issues and arguments coalesce around the question of whether the price premium of a fixed price full requirements product is worthwhile for all bundled customers considering the benefits of such a product and whether the default rate should compete head on with ARES offering similar products. The IPA created a model to estimate the cost premium – and ICEA has created a competing model – to allow the Commission to make an informed decision weighing the costs and benefits. The IPA notes that it undertook its analysis so the Commission could make an informed, data-driven decision on the issue. The IPA says it has reviewed the data and arguments provided in Comments and Objections and still does not recommend a full requirements procurement at this time, regardless of which model the Commission credits. (IPA Response at 5)

The IPA states, although outside of the traditional scope of the Procurement Plan, it appears that some of ICEA's arguments about possible hidden costs from the IPA's laddered block procurement approach are immediately remediable through improvements to how a price-to-compare is communicated. The IPA says while the Plug In Illinois website contains a detailed explanation of the PEA, it is not known how consumers understand or use that information. The IPA asserts to the extent that "hidden" costs can be exposed and explained, consumers will get more complete price signals and be better able to make informed decisions. While the IPA understands that such changes may not necessarily lead ICEA to withdraw its full requirements proposal, it believes it would be a low-cost step in the right direction. The IPA is willing to participate in any process to make changes to how the price-to-compare is presented and conveyed to customers. (IPA Response at 5-6)

ComEd and AIC question whether the IPA has the authority to procure full requirements or other non-block energy products. The IPA suggests this question may be moot if the Commission does not accept ICEA, RESA, and Exelon's proposal for a full requirements purchase, but in order to better inform the Commission the IPA believes it is prudent to provide the outlines of its authority so that other parties at least have the opportunity to respond in Replies to Objections in this docket without resorting to supplemental filings. (IPA Response at 6)

The IPA says it has procured energy in ways other than the block procurement explicitly identified in Section 16-111.5(b)(3)(iv) of the PUA. According to the IPA, as part of the 2010 LTPPAs with renewable developers, the IPA procured energy in addition to RECs that cannot be fairly characterized as a block transaction. The IPA claims this is consistent with the statutory language that requires the IPA to detail "the proposed mix and selection of standard wholesale products . . . **including, but not limited to** . . . " the products detailed in Section 16-111.5(b)(3)(iv). (IPA Response at 6-7, emphasis added)

The IPA also argues procuring full requirements products could be done consistently with the procedure required for energy products pursuant to Section 16-111.5(e)-(g), provided that the full requirements product was standardized to the point that bidders were only competing based on price. The IPA says although there is not an "index price" for full requirements to the IPA's knowledge, it would still be possible to develop reasonable benchmarks if supplier risk premiums can be successfully modeled (as the IPA and ICEA have attempted to do for the present docket). The IPA states although the term "standard product" is not defined in the PUA or the IPA Act, nothing in the description of standard products in Section 16-111.5(b)(3)(iv) requires a market-traded commodity price. If such a price was required, the IPA says it would not have been able to procure the LTPPAs, where there is no index price for new build wind or solar in Illinois and adjoining states. (IPA Response at 7)

The IPA claims Illinois courts have given effect to terms of enlargement such as "including" to permit expansion beyond enumerated terms – language that trumps the cannon of statutory construction expressio unius est exclusio alterius. (IPA Response at 7, citing Paxson v. Board of Educ. of School Dist. No. 87, 658 N.E.2d 1309, 1314-1315, 276 Ill. App. 3d 912 (1st Dist. 1995) The IPA believes the term "including, but not limited to" is an even more explicit term of enlargement, and should be given proper effect in this case. The IPA contends although the framers of the statute certainly expressed a preference for certain block energy products by explicitly naming them, the phrase "including, but not limited to" demonstrates the General Assembly's intent to allow the IPA to propose procurements beyond block energy products. (IPA Response at 7-8)

In its Reply to Responses, the IPA notes AIC and ComEd had both raised questions as to whether the IPA had the authority to procure a full requirements product, but neither provided additional legal arguments in their respective Responses. In contrast, the IPA says Staff, ICEA, and Exelon all provided similar legal justifications as the IPA did in its Response. The IPA does not recommend a full requirements procurement at this time, but the IPA recommends that the Commission find that non-block energy procurements are authorized under Section 16-111.5(b)(3)(iv). (IPA Reply at 5-6)

In its Reply to Responses, the IPA states after reviewing the Responses, the IPA has not found sufficient reason to change its position from its Response. The IPA believes that the analysis provided by both the IPA and ICEA has essentially reduced the matter of full requirements to a policy question. The IPA also believes, as Staff, CUB, and the AG point out, the question is not whether full requirements has a price premium over the IPA's current procurement approach, but that whether the benefits of a full requirements procurement would lead to bundled rate customer benefits that exceed those premiums. The IPA maintains this is a policy argument that the Commission is fully equipped to resolve. Based on the policy arguments, the IPA recommends that the Commission not require a full requirements product at this time. (IPA Reply at 2-3)

The IPA finds the analysis of the AG and CUB persuasive on the policy questions. The IPA raised a similar argument in its Response, and concurs with the AG's point that fixed price full requirements products are already offered on the market at competitive rates. Similarly, it is not clear to the IPA why the bundled product must be procured exactly the same way as market competitors, because any customer who wishes to have a fixed price product may select from a variety of products at virtually any time. The IPA says both the AG and CUB also argued that the other risk management tools that the IPA has proposed in this docket (including smaller standard blocks and a second procurement) provide better value to ratepayers than a full requirements procurement. Conversely, the IPA finds ICEA's argument that ComEd's voluntary PEA cap leads to carrying charges borne by ratepayers does not justify the cost premium. (IPA Reply at 3-4)

According to the IPA, one of the important prerequisites for the retail market to function properly is that customers have adequate information to make purchasing decisions between bundled and other products. Conversely, the IPA says if the way the bundled rate is conveyed to customers is providing incorrect price signals - or those price signals are obscured - the retail market could be at a disadvantage in competing with the bundled rate. As a strong supporter of the competitive retail market, the IPA believes that the bundled rate should not be given an unfair competitive advantage by providing information that customers are not able to translate into informed purchasing decisions. (IPA Reply at 4)

The IPA is not sure a formal Commission investigation is necessary, as CUB suggests, especially if stakeholders can work with the Commission's Office of Retail Market Development ("ORMD") on consensus changes. However, the IPA fully agrees that the Price-to-Compare should provide customers with the best and most useful information possible. (IPA Reply at 4-5)

The IPA also fully endorses the AG's recommendation that if there are concerns with how the PEA is administered, those concerns should address the PEA directly. The IPA is aware that ORMD has previously reviewed and sought stakeholder input on how PEA is presented and explained to customers, and believes additional such conversations could address stakeholder concerns with the PEA. The IPA plans to be a participant in discussions - formal or informal - about how the bundled rate (and specifically the PEA) are expressed to customers. (IPA Reply at 5)

Although not specifically raised by any other party, WOW argues that any full requirements purchase should not include the procurement of renewable energy resources. The IPA understands WOW to mean that the Commission should not change how renewable resources are procured, even if a full requirements energy product is ordered. Although the IPA does not recommend a full requirements energy procurement at this time, the IPA agrees with WOW that no changes should be made (nor have they been proposed) to how the IPA procures renewable resources. (IPA Reply at 8-9)

In its Brief on Exceptions, the IPA indicates it did not respond to Exelon's suggestion that the IPA should not procure energy beyond May 2016 because the Plan did not specifically calling for any procurement in that timeframe for ComEd. The IPA notes that while the Plan does propose procurement after May 2016 for AIC, the IPA says the discussion of full requirements contracting appears to be focused primarily on procurement for ComEd. The IPA says it is less clear what Exelon believes should be proposed in the future for AIC.

6. WOW's Position

WOW notes that ICEA, Exelon, and RESA propose that the IPA use FPFR contracts in 2014-2015 instead of the block and spot procurement method proposed by the IPA. RESA and Exelon support the proposal and redline revisions ICEA put forward in its comments on the draft 2014 Electricity Procurement Plan submitted to the IPA on September 16, 2013. ICEA's proposal is that 30% of the bundled service load of ComEd's eligible retail customers will be supplied through FPFR products during the June 2014-May 2015 period, leaving the possibility for further FPFR product procurements to be included in future IPA Plans. What is unclear to WOW about the FPFR approach is how it would procure renewable energy resources and do so within the Delivery Year RPS Budget. WOW suggests a Full Requirements contract should include a renewable energy resource component, however, WOW says the proposal was silent regarding renewable energy resources. It is conceivable that the proposal was intended to be an alternative to energy procurements, but WOW believes that needs to be clarified. (WOW Response at 2)

According to WOW, the FPFR should not include the procurement of renewable energy resources used by the utilities to comply with their RPS requirements for a few reasons. WOW says there is no immediate need for renewable energy resources in the 2014-2015 period. WOW notes the 2014 Plan has identified that the utilities are short in procuring certain target volumes of photovoltaics and distributed generation but that the IPA has chosen to not propose holding a renewable resource procurement in 2014-2015 because the July load forecast indicates that both utilities' REC costs are likely to be in excess of their Delivery Year RPS Budget. WOW also says ICEA, RESA, and

Exelon have not explained how an FPFR would procure cost effective renewable energy resources in compliance with the Section 1-75(c)) of the IPA Act in an open and transparent manner that allows for input from interested stakeholders. WOW asserts that under their proposal it is unclear whether the IPA would prescribe the renewable energy resource products that would be procured, whether the FPFR supplier would have discretion in what renewable energy resource products it would procure, and if the latter how the FPFR supplier would demonstrate that its products comply with the cost effectiveness test. (WOW Response at 2-3, Reply at 6)

If FPFR is approved WOW recommends that that it not include the procurement of renewable energy resources and that the IPA continue to analyze and develop renewable energy resource procurement plans on behalf of the utilities. (WOW Response at 3, Reply at 6)

WOW says that the concerns it raised in its Response were not addressed in ICEA's, Exelon's or RESA's responses to other parties. Thus, WOW reiterates its concerns and its recommendation that in the event that FPFR is approved, WOW recommends that it not include the procurement of renewable energy resources and that the IPA continue to analyze and develop renewable energy resource procurement plans on behalf of the utilities. (WOW Reply at 6)

7. The AG's Position

The AG believes the Commission should decline to adopt the ICEA proposal. The AG states there is risk of customers migrating back to default supply from individual alternate supply contracts or from expiring municipal aggregation deals. In the AG's view, the question is what strategy or mix of strategies should be used to address that risk. The AG believes that the IPA has appropriately and thoroughly analyzed the risk management tools available to it and has chosen the approach that its analysis has shown to be the least cost. The AG says this approach involves the following elements:

- Decreasing the size of procurement blocks from 50MW to 25MW;
- Using the April 2014 procurement to fully hedge the summer 2014 period and to hedge the remainder of the 2014-2015 delivery period at 75 percent;
- Planning a second procurement event to be held in September 2014 unless ComEd's load drops significantly below current projections or it is determined that benefits do not outweigh the costs of holding a second event; and
- Implementing lower hedging strategies for subsequent years in the plan.

The AG believes these are sensible adjustments to the IPA's traditional procurement approach that are designed to account for the risk that significant amounts of load could return to default supply. The AG says in crafting its risk management approach, the IPA investigated alternative strategies such as full requirements contracts or use of options but found the continuation of the IPA's past strategy at this time to be the most prudent option and the most likely to produce its statutorily mandated objective. (AG Response at 2-3)

The AG notes ICEA argues that further adjustments should be made to IPA's analysis of full requirements based on the NorthBridge report it submitted, which asserts that these adjustments could make full requirements appear more "reasonable" as an option. According to the AG, even if these adjustments are warranted and do result in a lower premium projection for full requirements, there is still the issue of transaction costs if ICEA's proposal is adopted by the Commission. The AG says, as the IPA points out, the statute requires the procurement administrator to develop price benchmarks that can be used to evaluate bids on each product offered in the procurement event and also to develop contract forms for use with the winning bidders. In the AG's view, even adding a limited, experimental full requirements product would still involve developing an additional set of benchmarks and contracts beyond that already required by the IPA's traditional procurement approach. The AG says the IPA considered the possibility of using a fraction of the utilities' load as a type of full requirements pilot program but concluded that the overhead cost of designing a price benchmark and a procurement mechanism for such a different product is not justified given that hedging using standard block products represent a less expensive alternative. (AG Response at 3-4)

The AG says it has previously commented that the IPA's use of block-and-spot has produced beneficial results for consumers. The AG believes the IPA has proven that it can manage the load and take advantage of the market using its block-and-spot approach. In the AG's view, there is no reason to cede managing the market to an outside supplier at a premium. (AG Response at 4)

ICEA and RESA suggest that the IPA should shift toward fixed-price, full requirements contracts because the block-and-spot approach, coupled with the purchased energy adjustment PEA mechanism, causes price distortion and prohibits default supply customers from clearly evaluating differences in the cost of default and alternative supply offerings. The AG claims this is not a persuasive argument for altering the IPA's procurement approach. The AG asserts the cost of managing the load is transparent in the block-and-spot method, via the PEA. If there are concerns with how the PEA is administered, the AG suggests those concerns should address the PEA directly. The AG believes it is inappropriate to try to side-step potential PEA issues by forcing the IPA into a more expensive procurement strategy. (AG Response at 4-5)

The AG says in today's energy market in Illinois, there are a variety of suppliers offering a variety of contracts for consumers and municipalities to choose from, including both fixed-price and variable rate plans. If there are customers who are unhappy with the variability in default supply price due to the IPA's block-and-spot procurement strategy and the PEA system, the AG suggests those customers have many fixed-price options available to them from alternate suppliers. According to the AG, Illinois consumers benefit when more than one cost-effective procurement approach is utilized in the state both because they have more options and because different procurement approaches provide a check on the reasonableness of the rates obtained through the various options. (AG Response at 5)

8. Staff's Position

By way of background, Staff notes that prior to enactment of Section 16-111.5 of the PUA and the IPA Act, procurement auctions were conducted by NERA on behalf of AIC and ComEd, pursuant to an authorizing order of the Commission. The contracts that were awarded through the auction were FPFR contracts. Staff states while the creation of Section 16-111.5 of the PUA and the IPA Act conceivably could be interpreted as a rebuke of everything about the 2006 auction process, neither the post-2006 PUA nor the IPA Act appears to prohibit FPFR contracts from being acquired through the IPA procurement process. Staff suggests the most relevant statutory provision is Section 16-111.5(b)(3)(iv) of the PUA, which requires each procurement plan to include:

> the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts, including but not limited to monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.
> (Staff Response at 2-3)

Staff says while the above provision does not single-out FPFR contracts as among those considered to be "standard wholesale products," the list that is provided is preceded by the phrase, "including but not limited to." When interpreting a statute, Staff says the primary objective is to ascertain and give effect to the intent of the legislature. (Staff Response at 3, citing Metro Utility Co. v. Illinois Commerce Commission, 262 Ill.App.3d 266, 274 (1994)) Staff also says the best indication of what the legislature intended is the statutory language itself and that clear and unambiguous terms are to be given their plain and ordinary meaning (Id., citing West Suburban Bank v. Attorneys Title Insurance Fund, Inc., 326 Ill.App.3d 502, 507 (2001)) and where statutory provisions are clear and unambiguous, the plain language as written must be given effect, without reading into it exceptions, limitations, or conditions the legislature did not express. (Id., citing Davis v. Toshiba Machine Co., 186 Ill.2d 181, 184-185 (1999))) Staff says since the language "but not limited to" exists in Section 16-111.5(b)(3)(iv), the plain language indicates that other products could be considered.

Staff notes in support of its proposal, ICEA submitted with its Objections a Report entitled, "Merits of Incorporating Fixed-Price Full Requirements Products in the Illinois Power Agency Plan," prepared by Mr. Fisher of NorthBridge. In this report, Mr. Fisher explains and compares the advantages and disadvantages of FPFR contracting relative to the "block-and-spot" procurement approach, which has been favored by the IPA, to date. In Staff's view, Mr. Fisher's findings largely boil down to this:

- FPFR contracts expose eligible retail customers to less risk than the block-and-spot approach.
- Retail prices under FPFR contracts are more transparent than those under the block-and-spot approach, facilitating more direct and timely comparisons to price offers from ARES. While the wholesale prices of the fixed-quantity "block" contracts acquired through the IPA procurement process are as transparent as the prices of FPFR contracts, wholesale spot prices are not nearly as transparent. Spot prices are unknown at the start of a plan year, and they vary hourly throughout the year, which affects retail rates under the block-and-spot approach. In contrast, once FPFR contracts are in place, spot prices have no affect on retail rates.
- The prices of FPFR contracts entail a premium over those of the fixed-quantity "block" contracts that are used in the block-and-spot approach.
- Bidders for FPFR contracts compete on the basis of the lowest price to satisfy all aspects of eligible retail customers' load requirements, including the portfolio management function. In contrast, under the IPA's current block-and-spot approach, portfolio management decisions are made through an annual regulatory process; there is no competition among qualified parties to determine the most cost effective ways to develop and manage supply portfolios that allow for the least-cost provision of fixed-price bundled service for customers.

(Staff Response at 4-5)

Staff is in complete agreement with these findings. Staff asserts, for essentially the same reasons, Staff supported the full requirements approach when ComEd and AIC proposed it and the Commission approved it in Docket No. 05-0159 and Docket Nos. 05-0160/05-0161/05-0162 (cons.). (Staff Response at 5)

Staff says another component of Mr. Fisher's report is a critique of the IPA's analysis of full requirements contracts. Among his findings are:

- The IPA's analysis is based on an unsupported and untested assumption about FPFR product pricing.
- The IPA's analysis omits or underestimates various drivers of costs and risks that are directly borne by customers under the block-and-spot approach, but from which the FPFR product approach provides protection for customers.
- The IPA's analysis of the FPFR product approach involves a melding of various simulations, in which distributions of various outcomes under different simulations are somehow combined, as opposed to a performing a straightforward simulation of the FPFR product approach.
- The IPA's analysis of the FPFR product approach relative to the block-and-spot approach does not address all of the aspects of costs and risks that are of concern with respect to a given bundled service supply approach.
- The IPA does not appear to consider the most likely way that FPFR products would be defined and integrated into the existing supply portfolio.

(Staff Response at 5-6)

Staff states while Mr. Fisher's critique seems persuasive, Staff reserves judgment until the IPA has had an opportunity to reply. Staff noticed some of the same potential flaws in the IPA's analysis. However, since Staff was not planning to propose a return to FPFR contracting, Staff saw no point in raising its concerns in its Objection to the Plan. Additionally, Staff did not have an alternative analysis to present, while Mr. Fisher apparently did. (Staff Response at 6)

Staff suggests of the greatest interest to the Commission would be Mr. Fisher's assessment that:

> Robust quantitative analysis based on actual market data from a region in which the block-and-spot approach and the FPFR product approach simultaneously had been implemented indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is reasonable. Specifically, the analysis indicates that, in comparison to the FPFR product approach, the increases in risk borne by residential customers under the block-and- spot approach are not balanced by a proportionate decrease in the expected default service rate level.

(Staff Response at 6-7)

Staff indicates Mr. Fisher presents a table, summarizing the results of the "most recent" of the quantitative analyses alluded to above. The analysis was performed in 2012 for PECO Energy Company. The table relates to that utility's residential default service load, and it shows "Block-and-Spot Approach with 80% Target" vs. "FPFR Product Approach." A second table duplicates the first, but with "Block-and-Spot Approach with 106% Target" vs. "FPFR Product Approach," to render it more relevant to the IPA's proposed hedging strategy. Staff says the latter table shows that, had PECO utilized a block-and-spot approach with a 106% hedge ratio, the decrease in expected average costs would have been only $0.13 per MWh (a 0.2% savings over the cost using the FPFR product approach). Staff indicates the risk of "rate shock" and the risk of "supply cost surprise" under the block-and-spot approach would have increased by $5.11 per MWh (62%) and $4.65 (169%), respectively. For purposes of the analysis, Staff says Mr. Fisher defined "rate shock" as the "maximum rate change over a given period of time (e.g., looking across a year, what is the largest increase in the rate versus what it was six months earlier)." He defined a "supply cost surprise" as the "difference between actual (ex-post) and forecasted (ex-ante) supply costs (e.g., how do actual supply costs over a twelve-month period compare to expectations three months before that period began)." (Staff Response at 7-8)

Staff claims it has not had time to evaluate Mr. Fisher's data and methodology. Staff says it cannot render an opinion about Mr. Fisher's conclusions. However, by utilizing actual market data from a region in which the block-and-spot approach and the FPFR product approach have been simultaneously implemented, it appears to Staff that Mr. Fisher is on the right track. (Staff Response at 8)

Staff believes AIC's proposal to delay debate over full requirements contracts is unwarranted. Staff notes AIC raises several issues that would need to be addressed before implementing a strategy involving “Full Requirements” type contracts. Staff agrees with AIC's issues that must be addressed before implementing a strategy involving full requirements contracts. Staff says the legality of such a strategy should be near the top of the list. Staff suggests how to transition from the current strategy to one that includes full requirements contracts is another important issue that should be added to AIC's list. (Staff Response at 23-24)

Staff does not agree that debating at least some of the most fundamental issues should be postponed until the quantities specified within the utilities’ existing contacts begin to fall well short of forecasted demand, as AIC implies. Under that condition, Staff suggests the debate may never be held. On the other hand, Staff agrees that now would not be a particularly good time to begin implementing a strategy involving full-requirements contracts for AIC, due to the current state of AIC’s portfolios. Staff suggests the same is not necessarily true of the ComEd portfolio, though. (Staff Response at 24)

In its Reply to Responses, Staff notes it has taken no position on the merits of the ICEA/RESA/Exelon proposal to incorporate full requirements contracts into ComEd’s June 2014-May 2015 portfolio. However, Staff has several concerns with the IPA, AG, and CUB responses to ICEA, RESA, and Exelon. (Staff Reply at 4)

Staff complains that both the IPA and the AG summarily dismiss the analysis presented by ICEA. Not only does the IPA fail to critique the analysis presented by the ICEA, Staff says the IPA does not rebut the ICEA’s critique of the IPA’s analysis. Staff says the AG disregards the ICEA analysis and simply implores the Commission to defer to the IPA’s robust analysis. Staff indicates CUB does not even mention ICEA’s analysis. In Staff's view, this lack of engagement lends additional credence to the analysis presented in ICEA’s Objections and invites skepticism with regards to the analysis presented in the IPA’s Plan. (Staff Reply at 4-5)

Staff states while recognizing that a fixed-price full requirements product would provide greater price stability for bundled customers than the current (and proposed) system of procurement, the IPA notes that if the bundled rate presents excessive perceived risk for a bundled service customer, the customer may easily choose a fixed price full requirements offer from an ARES. Staff says the AG makes a similar argument. In Staff's view, this shared sentiment by the IPA and the AG seems to be diametrically opposed to the IPA’s statutorily mandated objective to, develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. Staff says rather than empowering the utility to provide the least risky electric power option to customers classes that have not been declared competitive, the IPA and the AG suggest that ARES should and will provide that option, instead. (Staff Reply at 5)

Staff also complains that neither the IPA nor the AG address the concern raised by AIC about the dramatic price increases to eligible retail customers that can occur if the IPA's block hedges are well in excess of requirements due to customer switching (to ARES). Staff claims full-requirements contracts completely avoid that scenario. (Staff Reply at 6)

Staff notes the AG claims that the IPA's use of block-and-spot has produced beneficial results for consumers, insofar as the IPA's 2012 procurement events produced prices slightly below market prices for comparable products and comparable time periods. According to Staff, there are two things wrong with this pair of claims. First, Staff says the IPA's procurement events have only been for the "block" part of the "block-and-spot" approach. Staff asserts that ignoring the "spot" portion of the strategy misses a good portion of the costs and risks associated with the strategy. Second, Staff claims the AG's analysis of the 2012 procurement events had significant problems, as Staff pointed out in 2012, when the AG first made the claim that the IPA event produced prices slightly below market prices for comparable products and comparable time periods. Staff contends the AG's claim is left unsupported. (Staff Reply at 6)

Staff says the "tables" (actually graphs) included in the AG's Initial Comments do not accurately display the average winning prices from this year's IPA procurements. Staff claims it displays some winning prices for several delivery periods that were not even included in this year's RFPs. (Staff Reply at 6)

Staff also asserts those inaccurately-displayed winning prices are compared against what the AG calls "the associated market prices," which are labeled in the graphs as "NYMEX Futures." Staff says there are many electricity products traded on NYMEX. While the AG does not indicate which electricity products it chose for comparison purposes, assuming the AG's data were collected on or about the day of the IPA's energy RFPs, Staff has determined through inspection that the data for the ComEd graphs are definitely not for the Northern Illinois Hub NYMEX ("NIHub") contracts. Staff believes the data appear much more likely to be for the PJM Western Hub NYMEX contracts. This surprises Staff since the spot prices for energy at the Northern Illinois Hub traditionally have been very close to ComEd Zone spot prices, and much closer to ComEd Zone spot prices than PJM Western Hub spot prices. Furthermore, Staff claims Western Hub prices are typically much higher than ComEd Zone prices. (Staff Reply at 7-8)

Staff asserts that using the actual average winning prices from this year's IPA procurements, and the futures prices for the Northern Illinois Hub NYMEX contracts, paints a somewhat different picture than the one painted by the AG's presentation for ComEd. According to Staff, the average winning prices of the small hand-full of contracts purchased for ComEd were above rather than below the NI-Hub daily settlement prices around the time that bids were received, evaluated and approved by the Commission. Staff also claims a similar picture would emerge for AIC, and for both utilities in prior years' RFPs. (Staff Reply at 8-9)

While Staff believes the Northern Illinois Hub NYMEX contracts provide a better point of reference than whatever NYMEX contracts the OIAG employed, Staff also recognizes Northern Illinois Hub NYMEX contract settlement prices are not an ideal point of reference for various reasons. Staff says beyond a certain number of months, the NYMEX settlement prices lack the expected seasonal pattern; rather, they seem to reflect assessments of calendar year products. Staff also says there are distinct differences between the Northern Illinois Hub NYMEX contracts and the contracts used by the IPA (margin requirements being one good example). Due to such differences, Staff claims the existence of premiums for the IPA-solicited energy products relative to NYMEX futures is not unexpected. Staff states from the buyers' perspective, there are certain advantages to the IPA products relative to the NYMEX products. Staff believes whether those advantages are worth the level of observed premiums is a valid subject of inquiry, but not one attempted in Staff's reply comments. (Staff Reply at 10)

Staff acknowledges that the parties have presented some valid reasons to approach full requirement contracting with caution. Staff notes the AG mentioned administrative costs associated with developing an additional set of standard contracts and an additional pricing benchmark. AIC and Staff have both indicated how AIC is already over-hedged for most of the 2014-2015 plan year. In Staff's view, unless the Commission also authorizes a large sell-off of AIC's existing "long" position, AIC simply does not need any additional hedges. Staff notes AIC, ComEd, and Staff raise various issues that should be addressed before soliciting bids for full requirements products. (Staff Reply at 10)

According to Staff, in regards to the IPA and the AG, their opposition to the full requirements approach seems disproportionate, given the advantages of full requirements contracting that have been identified. Staff claims their preference for the block-and-spot approach also seems disproportionate, given the problems and potential problems with the approach that have been identified. It seems to Staff that the IPA has not analyzed adequately the issues surrounding full requirements contracts. (Staff Reply at 11)

While Staff takes no position on the merits of the ICEA/RESA/Exelon proposal to incorporate full requirements contracts into ComEd's June 2014-May 2015 portfolio, Staff recommends against the Commission making any findings in this docket that would appear to foreclose the utilization of full requirements contracts in the future. On the contrary, Staff recommends that the Commission find that full requirements contracts are "standard wholesale contracts." (Staff Reply at 11)

9. CUB's Position

CUB does not believe that any use of full requirements products is justified at this time. CUB says it is true that, as the IPA explains, its historic procurement strategy of buying power in laddered fashion means that trends in customer migration to and away from utilities can be magnified if there is a lag in reflecting the utility's energy costs in customer rates. CUB states volume changes resulting from these pricing differences may result in additional price risks for utility customers. (CUB Response at 2-3)

In CUB's view, the IPA accurately captures the many risk factors that will affect how much or how little difference there is in final energy supply costs from initial energy cost estimates. CUB says prominent among these are capacity prices, energy prices and customer switching. CUB believes full requirements procurement provides customers with price insurance against these risks, insurance which is translated into a price premium. According to CUB, as the IPA explains, the choice to buy full requirements should not depend on the absolute magnitude of that price premium but rather on whether that price premium is comparable to the value that consumers would obtain by eliminating the uncertainty around the price. CUB asserts for a full requirements supply hedge, the IPA's own analysis shows that the risk premium is too expensive compared to other management tools, such as energy efficiency and demand response, identified by the IPA. CUB believes ComEd was correct that here in Illinois, the IPA exists in part precisely because of problems associated with full requirements contracts, and managing the risk associated with supply prices and load size is the reason a third-party agency like the IPA was created. For this 2014 in particular, CUB says the limited size of the current proposed energy procurement does not justify the development of a contract and the implementation of a procurement event for a full requirements product. In CUB's view, the IPA analysis clearly shows that the full requirements approach leads to consumers paying a large price premium that is not in the public interest. (CUB Response at 3)

CUB supports the conclusion of the IPA that alternatives to full requirements contracts should be adopted to manage supply and price risk. Should the Commission determine that the concerns raised by ICEA regarding the comparability of energy prices offered by the utilities and energy prices offered by ARES, CUB would support an investigation by the Commission into how the Price-to-Compare methodology should be adjusted to allow for a more precise comparison. (CUB Response at 4)

10. ComEd's Position

While ComEd takes no position on ICEA's recommendation at this time, it notes that any finding on the issue must be consistent with the law. ComEd notes in particular, Section 16-111.5 of the PUA provides that the IPA is limited to proposing "standard wholesale products for which contracts will be executed during the next year." (ComEd Response at 13)

ComEd submits what it describes as two technical clarifications. First, in its critique of the Plan, ICEA argues that:

> The IPA Plan continues to rely upon a procurement and risk management strategy referred to as "block-and-spot" that places too much risk onto customers that remain on or return to bundled "default service" and also fails to allow such customers to see the actual and transparent price for

> electricity which they will ultimately be required to pay to ComEd (or Ameren). <u>While these costs do not **immediately** flow through to customers, they do exist and are increasing, as the most recent ComEd PEA filing shows.</u>

(ComEd Response at 13)

Though ComEd takes no position on the merits of this argument at this time, ComEd notes that the PEA charges are not expected to continue to increase as implied above. ComEd claims the PEA averaged a charge of 0.4 cents per kWh in the June 2011-May 2012 plan year; 0.2 cents/kWh for June 2012-May 2013; and 0.3 cents/kWh for the June 2013-October 2013 period. ComEd says looking forward, for the June 2015-May 2016 plan year they are expected to average near zero as the effects of the 3,000 MW long-term legacy swap are no longer present. (ComEd Response at 13-14)

Second, ComEd says regarding the Price-to-Compare, RESA states:

> Under the block-and-spot strategy, customers will make their retail electricity purchase decisions based upon the published utility Price-to-Compare, which will be the known price related to the block energy purchases, and will not include the spot purchases that must be made at a later date by the utilities to fulfill their wholesale electricity purchase needs for their retail customers. This means that customers will only see part of their future retail electricity costs reflected in utility prices, but will pay a larger number as the utility spot purchase costs get layered on at a later date.

ComEd notes in a similar vein, ICEA states:

> Under the block-and-spot approach, there is an inherent inability to match and follow load on a daily basis and thus causes ComEd and Ameren to conduct additional daily transactions in the PJM and MISO markets in order to match the actual load of the default service customers. Any costs incurred through these supplemental transactions (buying and selling) are settled through the Purchased Electricity Adjustment ("PEA") tariff, which default service customers are obligated to pay a monthly charge through a separate charge on their electric bill. Therefore, default service customers pay not only the Price-To-Compare ("PTC") tariff rate for their supply, but also any additional "transactional costs" needed to match load on a daily basis under the IPA's block-and-spot procurement approach.

(ComEd Response at 14)

In ComEd's view, both of these statements inaccurately characterize the calculation of the Price-to-Compare. ComEd says when it establishes the Retail Purchased Energy charges in Rate BES, which is the basis for establishing ComEd's Price-to-Compare, it includes all expected energy supply costs. ComEd says these costs include: the cost of the block energy, estimated spot energy purchases and sales (including the cost of the load shape and historical load/price variations), PJM charges, RECs, and internal ComEd costs. (ComEd Response at 14)

11. Commission's Conclusions

In this proceeding, ICEA proposes that the IPA Plan be revised so that 30% of the bundled service load of ComEd's eligible retail customers will be supplied through full requirements products during the June 2014-May 2015 period, leaving the possibility for further full requirements product procurements to be included in future IPA Plans. ICEA proposes all of the June 2014-May 2015 full requirements products will have a 12-month delivery period covering the entire June 2014-May 2015 period. ICEA proposes the products to be competitively procured in an RFP process that will run concurrently with the mid-April 2014 block energy RFP that is already included in the IPA Plan. ICEA proposes for twenty tranches of this full requirements product to be solicited, with each tranche supplying 1.5% of the bundled service load. ICEA proposes for bidders to submit fixed-price $/MWh bids to supply the full requirements product and for full requirements product tranches to be awarded on the basis of lowest price.

ICEA's proposal is supported by RESA and Exelon. At this time, the proposal is opposed by AIC, the IPA, the AG, and CUB and Staff and ComEd appear to be neutral. WOW's position on the underlying proposal is not entirely clear; however, WOW recommends that any full requirements procurement should exclude the procurement of renewable energy resources.

AIC questions whether full requirements products constitute a "standard product" as that term is used in the statute. Several parties, including the IPA and Staff, insist that full requirements products meet the statutory requirements to be considered a "standard product" and urge the Commission to reach that conclusion in this Order.

Having reviewed the statute and the parties' positions, the Commission agrees with Staff and the IPA that full requirements products should be considered a "standard product" under Section 16-111.5. As Staff noted, while the statute does not single-out full requirements products as among those considered to be "standard wholesale products," the list that is provided is preceded by the phrase, "including but not limited to." 220 ILCS 5/16-111.5(b)(3)(iv). The Commission notes that full requirements products will still be subject to the same determination of their compliance with the PUA as other standard wholesale products on a case-by-case basis and encourages the IPA to provide any benchmarks it deems necessary to ensure that compliance prior to the procurement of such products.

The Commission appreciates ICEA's efforts in raising this issue and providing the Northbridge Report. ICEA has raised the level of discussion surrounding this particular issue, and the Commission welcomes these efforts.

In procurement proceedings such as this, the Commission has competing objectives. On the one hand, the Commission must protect the interests of the eligible retail customers of ComEd and AIC. On the other hand, the Commission must also ensure procurement activities are conducted in a manner that promote a competitive electricity market in Illinois. The Commission must keep these objectives in mind when considering significant policy shifts including changes in procurement strategies that can have dramatic effects on eligible retail customers and the retail market as a whole.

While the Commission appreciates ICEA providing the NorthBridge Report, Staff indicates it has not had adequate time to fully analyze the Report. (See Staff Response at 8) Similarly, while the Commission itself has reviewed the NorthBridge Report, it is not comfortable with the level of review and feedback other parties provided. Staff, for example, also expressed concerns about the level of review performed by the IPA, the AG, and CUB. (See Staff Reply at 4-10) Again, with regard to load forecast, the RS express concerns about the limited amount of time to review load forecasting methodologies in this proceeding. (See RS Reply at 16-17) The Commission has similar concerns with regard to the limited time available to review the NorthBridge Report in this proceeding. The Commission has endeavored to review the record notwithstanding the limited timeframe. Some of the findings in the report are compelling, including the 2012 analysis of the PECO Energy Company, which notably included a simultaneous implementation of the block and spot and fixed price full resource products as similarly proposed by ICEA in this proceeding. Additionally, the report highlights several drawbacks with the IPA's analysis of the different procurement approaches. The Commission observes that Staff agrees with several of these critiques, and the IPA amended its analysis to address these issues.

The Commission notes that the only uncontested argument on this issue is that full requirements products will likely be purchased at a premium to traditional products. Even ICEA concedes this fact. (ICEA Reply at 5) The question before the Commission now is whether those premiums are outweighed by the "embedded" premiums included in the block and spot approach. The IPA and ICEA provide competing analyses on this question. It appears that the two competing analyses differ not in whether a premium exists for these products, but in the estimated size of the premium. While the Commission believes that fixed price full requirements products could prove to be appropriate risk hedging tools, to the extent those products satisfy the PUA, it does not believe sufficient evidence has been provided in this proceeding to make the policy shift at this time. Thus, the Commission declines to adopt ICEA's proposal.

Furthermore, the Commission believes the IPA has taken several steps to mitigate future load risks including decreasing the size of traditional procurement blocks, fully hedging the Summer of 2014, and adding a second procurement option in September. The Commission finds that these steps are reasonable alternatives to mitigate load risk for this year's Procurement Plan. For purposes of next year's plan, the Commission directs the IPA to include a more thorough and accurate analysis of the impacts of incorporating full requirements products into its procurement strategy, including the balance of benefits-to-premium costs of those products and any significant implementation costs it believes will result from this shift in procurement strategy. The

Commission is hopeful that this directive will allow the parties adequate time to consider this issue in the next proceeding.

To the extent that full requirements are not incorporated in the Plan, Exelon suggests the IPA should not procure energy beyond May 2016. Exelon claims that to do otherwise necessarily limits the flexibility for future plans, thereby preventing meaningful opportunity to re-visit alternative procurement options, such as full requirements, until 2018. The Commission notes that while Exelon raised this suggestion in its Objections, there was essentially no response from the other parties. Unfortunately, the Commission believes other parties were so focused on the ICEA proposal that Exelon's suggestion was overlooked given the short time frame for this proceeding. The Commission again notes that in procurement proceedings, it relies heavily on the IPA's input. In this instance, the IPA has not revised its proposed procurement plan or schedule. As a result of all the foregoing, the Commission declines to adopt the Exelon proposal.

For its part, the AG suggests if there are concerns with how the PEA is administered those concerns should address the PEA directly. The AG believes it is inappropriate to try to side-step potential PEA issues by forcing the IPA into what it believes is a more expensive procurement strategy. ICEA indicates that while it does not object to the AG's suggestion, improvements to the PEA will not fully mitigate the underlying problems. The Commission believes the AG and ICEA have a valid point that there may some problems with the way the PEA functions. Additionally, it appears to the Commission that while mitigating any such problems may not fully remove all possible underlying concerns with the PEA, it is a worthwhile proposition and the Commission encourages the parties to identify ways in which the PEA may be improved.

B. Energy Efficiency

1. ComEd's Position

In evaluating incremental energy efficiency, the Plan seeks Commission guidance on what it considers to be several open issues. According to ComEd, in considering such guidance it is important to keep in mind that the goal is not to create from whole cloth an energy efficiency procurement process for the IPA. ComEd says the Illinois General Assembly has already created that process in Section 16-111.5(B) of the PUA, wherein it set out in much detail the respective rights, obligations and powers of the IPA, the utilities, the Commission, and other stakeholders. (ComEd Objections at 2)

ComEd states that Section 16-111.5(B) first sets out the responsibilities of the utilities. That section provides that it is the utilities that are empowered to conduct the assessment of energy efficiency programs or measures that could be included in the procurement plan. In conducting this assessment, ComEd says it is the utilities' responsibility to identify the specific energy efficiency programs or measures that would be offered to retail customers and to conduct a solicitation process for requesting proposals from third-party vendors. In conducting the solicitation process, ComEd indicates the utilities are to consider input from the IPA. The utilities are then to provide the assessment and the documentation from the solicitation process to the IPA. (ComEd Objections at 2-3)

The IPA is to then make its own determination as to which of the energy efficiency programs and measures are cost-effective and to then include such programs and measures in its procurement plan. However, ComEd says this determination is limited to those energy efficiency programs and measures "included in the annual solicitation process and assessment submitted pursuant to paragraph (3) of this subsection (a)." ComEd repeats that the IPA is also empowered to provide input to the utilities for the annual solicitation process. (ComEd Objections at 3)

According to ComEd, the Commission's role, as set out in Section 16-111.5(B), is to review those energy efficiency programs and measures that are set out in the procurement plan, and to approve those that the Commission determines fully capture the potential for all achievable cost-effective savings. (Id.)

ComEd indicates that the Plan identifies the first issue as "a lack of an adequate feedback loop in the development of programs for consideration for inclusion in the procurement plan to ensure the statutory goal of 'fully capturing' the potential for all achievable cost-effective savings, to the extent 'practicable.'" ComEd believes this recommendation ignores the statutory framework. ComEd insists that framework provides for the IPA, as well as all other interested stakeholders, to provide feedback to the utilities in the development of the annual solicitation process. ComEd also asserts that nowhere within Section 16-111.5(B) is it stated that it is the goal of that section to fully capture the potential for all achievable cost-effective savings. ComEd says the only place that language appears in Section 16-111.5(B) is in reference to the review that the Commission is to conduct of the energy efficiencies measures included in the plan. ComEd contends no role is given to the IPA to pursue some unstated statutory goal to capture all cost savings identified in the potential study. ComEd claims even the Commission's role is limited to ensuring that the energy efficiency measures included in the plan capture all achievable cost savings. (ComEd Objections at 3-4)

ComEd says the Plan also recommends that the 2014 procurement proceeding serve as the forum for developing a "programmatic planning link" between the potential studies and the energy efficiency programs submitted to the IPA. ComEd believes the IPA again ignores the statutory framework. ComEd says that framework provides that the process used under Section 8-103 for the development of requests for proposals is to be the "programmatic planning link" between the potential studies and the programs submitted to the IPA, and not the IPA. In ComEd's view, the Plan provides no support for its implication that that process is either not working or otherwise inconsistent with the law. According to ComEd, neither the IPA Act nor the PUA establish or otherwise suggest that any other feedback loops or planning links are appropriate, needed, or allowed. ComEd believes the Plan should be modified to delete this section. (ComEd Objections at 4)

ComEd notes in its Objections, the AG recommends the Commission instruct the utilities to include proposals for expansions of Section 8-103 programs that will be proposed by the utilities in their September 1 three-year filings when it submits proposed programs to the IPA. ComEd believes it is unclear what the basis for this proposal is in relation to ComEd as ComEd did propose expanding and moving two Section 8-103 programs into its Section 16-111.5B portfolio with the IPA. Specifically, ComEd says it recommended expanding its Small Business Energy Services program and its Home Energy Reports program. ComEd recommends the Commission reject this request as it applies to ComEd. (ComEd Response at 15)

ComEd notes the AG argues that the utilities are more than likely aware of which programs will be the centerpieces of their Section 8-103 program portfolios when they submit their recommendations to the IPA for achievable, cost-effective efficiency programs. ComEd says the AG goes on to assert that there is no reason utilities should not be bidding into the IPA portfolio planned expansions of proposed Section 8-103 programs that they have concluded are cost-effective and are likewise proposing to be approved by the Commission in the Section 8-103 dockets. ComEd states while it may have an idea which programs it would like to include in its Section 8-103 portfolio, it is impossible to say with any certainty exactly which Section 8-103 programs will actually be approved. ComEd argues if that level of certainty were available, then the need for Section 8-103 proceedings would be rendered obsolete. Because the utilities do not know which programs will be approved in their Section 8-103 portfolios, ComEd says they cannot possibly know which programs to propose to expand and the AG's recommendation should be rejected. (ComEd Reply at 8)

According to ComEd, CUB disagrees that the Plan's discussion regarding the IPA's "programmatic planning link" proposal should be deleted. CUB argues that because the IPA and Commission are obliged to review whether all cost-effective energy efficiency is being captured, there would be no use for the utilities to submit a potential study for inclusion in the Plan and review by the Commission. ComEd finds CUB's arguments unpersuasive, says they ignore the unambiguous letter of the law, and believes they should be rejected. (ComEd Reply at 4)

ComEd says CUB recommends that the Commission require utilities to submit potential studies significantly earlier than presently required, stating they should be released in the fall of the year prior to the utilities filing the three-year portfolios. According to CUB, such change would allow utilities and vendors the opportunity to review and consider the most recent data on potential before designing and submitting program bids. ComEd finds this recommendation unreasonable and believes it should be rejected. (ComEd Reply at 4)

ComEd's primary concern with this recommendation is that it would extend the timetable so far out – adding nearly a year onto the current July 15 submission date – that it could diminish the accuracy of the data contained therein. ComEd also believes the recommendation is unnecessary because the statute dictates that the RFPs are in and of themselves part of the potential study ("in preparing such assessments, a utility shall conduct an annual solicitation process for purposes of requesting proposals from third-party vendors, <u>the results of which shall be provided to the Agency as part of the assessment, including documentation of all bids received</u>..." (ComEd Reply at 4-5, citing 220 ILCS 5/16-111.5(a)(3) (emphasis added)). Had the General Assembly intended the potential study to be completed prior to the utilities receiving the RFPs, ComEd says then it would have stated as much.

CUB recommends that the Commission mandate either the inclusion or exclusion of certain language contained in the RFPs, asserting that some language this year may have prevented efficiency providers from submitting program bids. While ComEd agrees that standardization of some terms may be beneficial to creating a more efficient RFP process, ComEd believes CUB's recommendations misconstrue the language and intent of the two clauses identified and should therefore be rejected. (ComEd Reply at 5)

CUB first asserts that ComEd's RFP states "that third-party vendor programs may be taken over by ComEd if ComEd believes it would "enhance" the program." ComEd contends this statement is incorrect as nothing in the RFP states that ComEd may elect to "take over" a third-party vendor program if it believes it could enhance the program. Rather, the RFP provides:

> The selected bidders will be responsible for program design/redesign, managing, executing, securing, documenting, and reporting energy savings and marketing of the program under review and approval by ComEd. Bidders should assume they will have design, execution, marketing and outreach responsibility for the purposes of this bid. However, upon review by ComEd it may be determined that the likelihood of achieving cost-effective savings would be enhanced by marketing the program under the Smart Ideas banner . . . .

According to ComEd, contrary to CUB's assertion, the RFP does in fact state that selected bidders will be responsible for program design, management, and execution. ComEd says it retains the ability to further market the program under its existing Smart Ideas banner. ComEd claims it is difficult to see how such provision might detract a vendor from submitting an RFP, particularly when the effect of the provision is to provide increased marketing for third-party programs. (ComEd Reply at 5-6)

ComEd contends CUB also speculates that third-party vendors may be dissuaded from submitting bids because ComEd accepted bids for programs lasting 1-3 years rather than indefinite time lengths. ComEd claims this assertion is inconsistent with its experience as it has generally had no difficulty in finding and retaining qualified implementation contractors. ComEd also argues this timeline makes sense as it aligns the timing of ComEd's 16-111.5B programs with its Section 8-103 programs, thus allowing ComEd to effectively coordinate both portfolios and minimize the risks associated with a long term or indefinite contract. More importantly, ComEd asserts the three-year horizon provides an important safeguard to ensure that third-party energy efficiency programs are not only well-managed, but also subject to review on a regular basis. ComEd says nothing prevents a program that has proven to be well-managed from being expanded or continued. Rather, ComEd claims this timeline ensures that the customers who pay for these programs are receiving quality programs with sufficient oversight. (ComEd Reply at 6)

In its Reply Brief on Exceptions, ComEd notes both the AG and the CUB propose revisions to the Proposed Order's treatment of feedback loops. It is unclear to ComEd what, if anything, these proposals seek to achieve or how they propose to do so. (ComEd RBOE at 2-3)

ComEd agrees that clarification regarding the role of the DCEO in incremental energy efficiency programs is warranted. Although DCEO's involvement in the EEPS is clearly spelled out in Section 8-103 of the PUA, ComEd says the General Assembly included no parallel language in either the IPA Act or Section 16-111.5B of the PUA, which govern the incremental energy efficiency programs subject to this proceeding. ComEd asserts that traditional principles of statutory construction confirm that where the law does not establish a unique right, no unique right exists. (ComEd Objections at 4-5)

ComEd argues that when construing a statute, the court's primary objective is to ascertain and give effect to the legislature's intent. (Id. at 5, citing People v. O'Brien, 197 Ill. 2d 88 (2001), citing Boaden v. Department of Law Enforcement, 171 Ill. 2d 230, 237 (1996)) ComEd also says the language of a statute is the most reliable indicator of the legislature's intent. (Unzicker v. Kraft Food Ingredients Corp., 203 Ill. 2d 64, 74 (2002), In re Detention of Powell, 217 Ill. 2d, 123, 135 (2005)) ComEd also says where the language is clear and unambiguous, the court will apply the statute without resort to further aids of statutory construction, including legislative intent. (Davis v. Toshiba Mach. Co., 186 Ill. 2d 181 (1999)) Courts should not insert words into legislative enactments when the statute otherwise presents a cogent and justifiable legislative scheme. (Hayes v. Mercy Hospital and Medical Center, 136 Ill. 2d 450 (1990), citing Hagan v. City of Rock Island 18 Ill. 2d 174, 179 (1959)) When an act lists things to which it refers, the court may infer that any omissions were intended as exclusions. (Id., citing Bank of Waukegan v. Kischer, 246 Ill. App. 3d 616, 620 (1993))

In ComEd's view, although the law provides DCEO with a unique role in Section 8-103 proceedings (e.g. "[t]he remaining 25% of those energy efficiency measures approved by the Commission shall be implemented by the Department of Commerce and Economic Opportunity, and must be designed in conjunction with the utility and the filing process,") there is no similar provision that applies to this Section 16-111.5 proceeding. (ComEd Objections at 5, Reply at 2-3)

ComEd argues that no language in Section 16-111.5(B)(5), nor any other provision of Illinois law, indicates or even suggests that DCEO should be treated differently than any other third-party vendor in the Section 16-111.5 procurement process. ComEd claims that the General Assembly included express provisions regarding DCEO's participation in Section 8-103 proceedings but was silent on the issue in Section 16-111.5. ComEd believes this confirms that the General Assembly did not intend for DCEO to receive distinct treatment in this proceeding. ComEd contends that while the law may not afford DCEO any unique treatment in the procurement process, nothing in the law forecloses DCEO from participating in IPA procurement events through the standard third-party request for proposal. (ComEd Objections at 5-6, Reply at 3)

In its Response to Objections, ComEd says it appreciates the AG's concerns regarding the participation of the DCEO in the procurement process, however, ComEd reiterates its position that no language in the law governing this proceeding, Section 16-111.5 of the PUA, nor any other provision of Illinois law, indicates or suggests that DCEO should be treated differently than any other third-party vendor in the procurement process. ComEd says no party, including DCEO, has submitted any evidence to the contrary. While the law may not afford DCEO any unique treatment in the procurement process, ComEd maintains nothing in the law forecloses DCEO from participating in IPA procurement events through the standard third-party RFP. ComEd believes the Commission should conclude that, going forward, if DCEO wishes to participate in the Section 16-111.5 procurement process, it must do so through the third- party RFP process set forth in the PUA. (ComEd Response at 16)

In its Reply to Responses, ComEd states DCEO incorrectly asserts that the IPA's decision to exclude DCEO from its 2014 Draft Energy Efficiency Procurement Plan is inconsistent with the intent of the PUA. In essence, DCEO argues that because a wholly different part of the PUA - Sections 8-103 and 8-104 - afford it with a unique role in proceedings governed by those provisions, the Commission should effectively cut and paste those provisions into Section 16-111.5, such that DCEO might also have a unique role in this proceeding. ComEd claims this request is legally improper, baseless, and should be rejected. (ComEd Reply at 2)

ComEd notes the AG continues to recommend that the Commission take evidence or comments on the bidding difficulties that have prevented DCEO's participation in IPA Plans to date. ComEd says the AG also states that once a clearer understanding of these contracting difficulties is presented, it is the AG's hope that the IPA, DCEO, and the utilities can craft an amendment to the Plan. While ComEd has remained open to dialogue on this issue throughout the course of this proceeding, it notes that, to date, no party has submitted any such evidence. ComEd maintains the Commission should hold that the proper avenue for DCEO to participate in a Section 16-111.5B proceeding is through the standard third-party request for proposal process. (ComEd Reply at 3-4)

ComEd indicates the Plan identifies two issues related to the topic of competition between incumbent utility programs and third-party RFP programs. Specifically, the Plan notes that there is ambiguity as to (1) what it means for a third-party bidder's proposed program to be competing with or be duplicative of a utility program; and (2) the authority of the Commission to reject a third-party bidder's program that is competing with or duplicative of a utility's program but which otherwise passes the standard for cost-effectiveness. (ComEd Objections at 6)

The IPA proposes to define "duplicative" as "a program that overlaps [with] an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers." It further proposes to define "competing" to mean such programs that are proposed in future years. ComEd agrees with these definitions. ComEd also agrees that a multi-factor inquiry would help ensure that such programs are evaluated under a consistent approach. In addition to the five factors recommended by the IPA, ComEd recommends that the following additional factors also be taken into account: (6) the effect(s) on utility joint program coordination, and (7) impact on Section 8-103 EEPS portfolio performance. ComEd also believes the Plan should clarify that if, in evaluating these factors, the utility identifies any of the factors as being a critical element of a third-party proposal, the utility can and should exclude the proposal from its Section 16-111.5B proposal to the IPA. (ComEd Objections at 7)

The Plan states that "parties should work collaboratively on contract principles for successful bidders, which may include pay-for-performance language and grant the utility "flexibility" to reward successful programs while minimizing resources spent on unsuccessful programs." ComEd agrees that pay-for-performance language, which is consistent with ComEd's current practice, should be a standardized contract term. ComEd believes the rest of the proposal is vague as it is unclear what precisely the IPA is asking the Commission to do. ComEd neither supports nor objects to the remainder of the proposal. (ComEd Objections at 7)

ComEd says the AG makes what ComEd describes as several confusing statements concerning duplicative and competing programs. Although the AG does not propose any specific modifications to the Plan, ComEd responds as follows. First, the AG states that "the Commission, and the Commission as final arbiter, should be presented with all programs that pass the TRC for purposes of evaluating what programs should be included within the IPA's procurement portfolio." ComEd says that the process it follows in deciphering which programs to include in its Section 16-111.5B submission is not a unilateral one, as the AG implies. ComEd asserts in advance of its initial procurement filing this year, ComEd sought input from the numerous stakeholders that comprise the stakeholder advisory group ("SAG"), which includes representatives from the AG and Staff, in order to collaboratively determine which programs should and should not be recommended for inclusion in the IPA's procurement portfolio. Second, the AG claims that "ComEd's stated rationale for excluding a program it deemed duplicative also highlights the inherent contradiction of excluding duplicative or competing programs that will end before the 2014 procurement takes place, but not including expansions of programs that have yet to be formally approved by the

Commission in Section 8-103 dockets." In its reference to "programs that will end before the 2014 procurement takes place," it is unclear to ComEd what the AG considers to be the problem and how it proposes to ameliorate said problem. (ComEd Response at 15-16)

According to ComEd, both the AG and CUB continue to endorse the notion that the Commission should be the "final arbiter" of determining which programs are duplicative and/or competing. While ComEd does not dispute the Commission's oversight of the Section 16-111.5B procurement process, ComEd believes their position is overstated and inconsistent with the statutorily-defined process. (ComEd Reply at 6)

ComEd states Section 16-111.5B provides that it is the utilities that are empowered to conduct the assessment of energy efficiency programs or measures that could be included in the procurement plan, stating: "each Illinois utility procuring power... shall annually provide to the Illinois Power Agency by July 15 of each year… an assessment of cost-effective energy efficiency programs or measures." Thus, in conducting this assessment, ComEd claims it is the utilities' responsibility to identify the specific energy efficiency programs or measures that would be offered to retail customers and to conduct a solicitation process for requesting proposals from third-party vendors. (ComEd Reply at 6-7)

ComEd says the utilities are then to provide the assessment and the documentation from the solicitation process to the IPA. ComEd says the IPA must then make its own determination as to which of the energy efficiency programs and measures are cost-effective, and then include such programs and measures in its procurement plan. ComEd asserts this determination is limited to those energy efficiency programs and measures "included in the annual solicitation process and assessment submitted pursuant to paragraph (3) of this subsection (a)." ComEd notes the IPA is also empowered to provide input to the utilities for the annual solicitation process. (ComEd Reply at 7)

According to ComEd, the Commission's role, as set out in Section 16-111.5(B), is to review those energy efficiency programs and measures that are set out in the procurement plan, and to "approve the energy efficiency programs and measures included in the procurement plan, if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103." ComEd argues that permitting the utilities to screen out duplicative or competing programs, consistent with the factors identified by the IPA in its Objections, is reasonable, appropriate, and consistent with the Act. ComEd does not oppose continuing the collaborative process used in this year's proceeding where it sought input from stakeholders in order to determine which programs should or should not be included in the portfolio. ComEd believes rehashing the issue through a litigated proceeding serves no interest other than to increase the expense and administrative burden of a process that can be handled far more efficiently. (ComEd Reply at 7-8)

2. AIC's Position

The IPA states that it may include cost-effective demand response products in its Procurement Plan. The IPA goes on to specify the requirements for the procurement and implementation of such demand response products. AIC says that because Section 16-111.5B of the PUA does not address demand response products (though certain provisions of Section 8-103 reference demand response programs), AIC understands that any approved demand response programs would be offered outside of the energy efficiency portfolio approved in this docket. In addition to the logistical difficulties of offering demand response products to eligible retail customers (i.e., reliably identifying those customers who are offered energy efficiency programs through the Plan), AIC says Section 16-111.5B's other restrictions on the provision of demand response products (e.g., cost-effectiveness) present significant barriers to offering any such products through the portfolio at this time. Although no incremental demand response products are proposed in this Plan, to the extent any demand response products are approved in future Plans, AIC states that they would not be offered through Section 16-111.5B programs, but through other channels. (AIC Objections at 8-9)

For the sake of clarity and completeness, AIC recommends the following change on page 81 of the Plan to reflect that savings targets are based on factors other than just maximum spending level for the utilities' implementer contracts:

> It should be noted that each of these savings targets is based on several factors, including bids, implementer estimates, and a maximum spending level for the utilities' implementer contracts.

(AIC Objections at 9)

Again, for clarity and completeness, AIC recommends the following change on page 82 of the Plan to reflect that net-to-gross can play a role in the front-end approval process. AIC states that NTG currently impacts the evaluation of whether a program is cost-effective, and if the NTG value is not fixed (or "deemed") for the year, there is increased uncertainty with respect to estimated savings values during the approval process:

> Other issues, such as verification, ~~or "net to gross,"~~ certainly play roles in Section 16-111.5B programs, but not necessarily in the front-end approval process to be carried out in this docket.

(AIC Objections at 9)

The IPA notes that "NRDC raised an interesting point that the third-party bids tended to be focused on retrofit programs rather than programs that would influence the purchase of efficient products." AIC does not disagree with NRDC's observation, but notes that the available energy efficiency programs reflect the current market. As such, AIC believes the focus on retrofit programs is not "problematic," as suggested by the

Plan and therefore should not be further addressed by the Commission or the IPA. AIC expects that as the market for energy efficiency products evolves, so too will the bids submitted to the IPA pursuant to Section 16-111.5B. (AIC Objections at 9-10)

The IPA states that legislative change would be necessary to address the "issue" that arises in each "transition year" (i.e., every three years) when the utility must propose energy efficiency programs pursuant to Section 16-111.5B before its Section 8-103 programs are approved. AIC says the issue, as explained in the Plan, is that the timing set forth in the PUA provides that the Section 16-111.5B programs must be bid and submitted before the Commission can review and approve the Section 8-103 programs for the next procurement year. AIC believes the approach taken this year by both AIC and ComEd seems to adequately account for the "transition year" issue without legislative change. (AIC Objections at 10)

The IPA states that it hopes DCEO and the utilities will coordinate so that DCEO programs can be included in the Plan in the future. AIC does not disagree with the spirit of the IPA's recommendation regarding utility-DCEO cooperation and looks forward to the continued collaborative relationship it has with DCEO. However, AIC echoes the Plan's concern with statutory limitations and other challenges (like contracting) that may require more than just coordination between the utilities and DCEO to resolve this issue. At this time, AIC recommends that a decision regarding how DCEO will participate in the IPA Plan be deferred. (AIC Objections at 10)

Noting that it is not aware of a Commission-approved standard for the terms "duplicative" and "competing" in the context of Section 16-111.5B, the IPA proposes definitions for these terms. The IPA proposes to use the term "duplicative" to mean "a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers." AIC does not disagree with this definition of "duplicative," and understands the definition to mean that a utility need not perform additional evaluation of the vendor, such as evaluating the vendor's reputation, creditworthiness, or references, before excluding the program. (AIC Objections at 10-11)

AIC believes the IPA's definition of "competing," on the other hand, is problematic. The IPA proposes using the term "competing" to refer to programs that would benefit from "multiple channels," and that "competing programs would be acceptable to the extent that the competition does not render one or both non-cost effective." AIC disagrees with this definition and with including such competing programs in the Plan. AIC asserts that allowing different vendors to offer essentially the same program to different geographic or end-use segments is more complex and potentially disruptive to the market than implied by the Plan. AIC believes this is especially true for programs that rely on mass-market communication channels, which could be negatively impacted by competing messages. (AIC Objections at 11)

According to AIC, the inclusion of competitive and duplicative programs presents problems such as: (1) inaccurate TRC calculations, since the TRC of a program is calculated based on the program in isolation (absent of duplicative or competitive programs); (2) market confusion and reduced savings caused by potential customer and program ally frustration, and reduced integrity for the energy efficiency program as a whole; (3) inefficiencies and duplication of program costs, especially in the cases of programs competing/duplicating expanded programs; and (4) additional risk associated with being required to contract (via the approval of all cost-effective programs identified in the IPA Plan) with new, competing vendors. (AIC Objections at 11)

AIC alleges that even the Plan recognizes that there are problems with including competing/duplicative programs, and notes that the utilities should "be given some level of discretion . . . in judging which programs to include and which ones [are] duplicative and [do] not add value." AIC states that in Section 7.1.4.2 of the IPA's proposed Plan, the IPA itself recommends excluding one of AIC's proposed programs because it would compete with an already-existing program implemented under Section 8-103. Regarding AIC's Student Energy Kits, "the IPA does not recommend the inclusion of [this] program under Section 16-111.5B" because "the market sector may be well served" by AIC's proposed student energy kit program offered by a different vendor and on a larger scale in its Section 8-103 portfolio. AIC supports the approach taken by the IPA with respect to AIC's Student Energy Kits and recommends that the IPA Plan clearly state that utilities have the authority to screen for programs that are competing/duplicative. When screening for competing/duplicative programs, AIC believes the utilities should be allowed to take into account the factors identified by the IPA, as approved by the Commission, if the Commission chooses to adopt the IPA's standard for duplicative or competing programs. AIC further requests that the IPA Plan be revised to reflect that neither duplicative nor competing programs should be approved pursuant to Section 16-111.5B(a)(3) or (5). (AIC Objections at 11-12)

AIC also recommends the following change on page 84 of the Plan to correct a small inaccuracy and to reflect the actual provider of the referenced program:

> Although it may be obvious in some cases (such as with ~~Ameren's~~ SAIC Small Business Direct Install program, discussed further below)

(AIC Objections at 12)

AIC recommends the following change on the first line of page 87 of the Plan to correct small, but important, inaccuracies:

> Class B and C office spaces are already served by ~~Ameren's~~ SAIC's program~~ (but not specifically targeted)~~, so failure to include the Bidder program would not hinder the statutory mandate to expand cost effective energy efficiency programs.

(Id.)

In Section 7.1.4.3 (page 87 of the Plan), the IPA says it would like additional discussion from AIC regarding its recommendation that it implement its small business direct install program at the base level (as opposed to an expanded version). AIC says it rolled out the small business direct install program only recently, on June 1, 2013. According to AIC, this program is a “feet on the ground program,” meaning that an AIC employee knocks on the door of businesses to ask if AIC could perform a quick assessment of the business facility. If the customer agrees, AIC indicates an assessment is completed that provides estimated savings, recommends measures the business could install, and provides the measures’ costs. If the customer wants to proceed with installing the recommended measure(s), the customer schedules an appointment for a contractor to install the measure(s). In AIC's IPA submissions for last year and this year, AIC says it had to estimate a number of variables to calculate the costs and benefits of this new program. AIC indicates estimates were used for the following variables: number of businesses that could be called on per day, number of businesses per day that would allow an assessment to be performed, number of assessments that would actually turn into installed projects, the mix of measures that would be installed, and the net-to-gross rate. AIC states that at the time of its Objections, filing the implementer is at the stage of obtaining the first field data to compare actual results to the estimates used in the program analysis. If the actual results are different than the estimates, AIC indicates both the savings and the total resource cost test would change. (AIC Objections at 13)

In its Reply, AIC notes the IPA defers judgment on the issue of whether AIC should expand its Small Business Direct Install program beyond the base level to wait until it hears from other parties. No other party submitted responses on this issue. However, on October 30, 2013, AIC says it received a letter from the vendor that withdrew the expanded bid due to “unanticipated dissimilarities” between what the vendor had modeled and the actual delivery approach that the vendor has been using in Illinois. In light of the vendor withdrawing its bid at the expanded level, AIC believes the Commission should approve AIC to contract with the vendor at the base level. (AIC Reply at 10)

According to AIC, although programs implemented under Section 16-111.5B do not have penalties for non-performance, AIC believes it has a role in assessing whether the budgets and savings bid for a program are reasonable and likely to be achieved. AIC says the IPA will rely on this expansion of energy efficiency instead of purchasing additional supply and AIC is reviewed by the Commission with respect to its management of energy efficiency programs. AIC does not believe programs submitted to the IPA should be “best efforts,” which could result in overstated savings and could complicate the implementation and management of this program. (AIC Objections at 13-14)

AIC believes that it is premature to increase the budget for this program from $8.7 million to over $18.5 million for a single year with no actual field results or evaluation. AIC says such an increase does not seem justified and would put AIC (as well as others, like the vendor) in a difficult position in managing this program if during the year actual results differ from dollars and volumes bid into the IPA for this year. AIC recommends that the small business direct install program be included in the IPA plan at the base level of 30,719 MWh. (AIC Objections at 14)

In its Response to Objections, AIC says the Commission should reject the AG's request that the final order in this docket require utilities to include expansions of their Section 8-103 programs for three reasons: (1) during transition years, utilities do not know what programs will be approved in their Section 8-103 portfolios at the time of their IPA submissions (and, for this year's proceeding, there is no mechanism for the utilities to change their IPA submissions at this point); (2) the utilities' approach this year adequately accounts for the transition year problem while complying with the law while also expanding programs; and (3) the consensus items from the IPA workshops prevent the expansion of Section 8-103 programs with overlapping two portfolios. (AIC Response at 9)

According to AIC, the transition year timing issue means that every three years utilities do not know which Section 8-103 programs will be approved at the time they submit their IPA proposals. In its Response and Objection to the IPA Plan, the AG dismisses the transition year timing problem. AIC says the AG argues that utilities should include expansions of their Section 8-103 programs in their IPA proposals, even in years where Section 8-103 programs have not yet been approved by the Commission. The AG makes light of the timing issue by saying, "the utilities are more than likely aware of which programs will be the centerpieces of their Section 8-103 program portfolios when they submit their recommendations to the IPA…" (AIC Response at 9-10, citing AG Objections at 2-3) AIC claims this statement does not reflect the reality that significant programmatic changes can occur (and have occurred) during the triennial proceeding to approve the utility's energy efficiency and demand response plan pursuant to Section 8-103. AIC states during the proceeding to approve AIC's Plan 2, the Commission ordered AIC to make a Compliance Filing that altered the Plan as originally proposed. (Id., citing Docket No. 10-0568, Order at 108) Accordingly, AIC says it filed a revised plan on January 20, 2011, in which significant changes were made to the originally-filed Plan 2. In its Compliance Filing, AIC says it explained the changes made to comply with the Commission's Final Order. AIC indicates such changes included increasing the number of dual-fuel measures and increasing the use of compact fluorescent lamps ("CFLs") in AICs residential lighting program. AIC asserts if during the last transition year (assuming Section 16-111.5B had been enacted and applied), AIC had been required to include expansion of its planned programs, the IPA submission would have been premised on incorrect information. AIC contends this example of what happened during AIC's Plan 2 proceeding illustrates why the AG's "overly-restrictive" proposal should be rejected. (AIC Response at 10)

AIC believes the second reason to reject the AG's request is that the approach taken this year by both utilities – to include discrete programs at expanded levels in their Section 16-111.5B portfolios – seems to adequately account for the "transition year" issue in a way that is consistent with the statute. Because the utilities do not know which programs will be approved in their Section 8-103 portfolios, AIC maintains they cannot propose expansions of those programs (overlapping both the Section 8-103 and IPA portfolios) as part of their IPA submissions. (AIC Response at 11)

AIC also contends the consensus items from the IPA workshops illustrate why Section 8-103 programs cannot be expanded and overlap in the IPA procurement plan. AIC says the recommendations from the IPA workshops establish that IPA and Section 8-103 programs must be bid, implemented, and managed separately. According to Staff's workshop summary report, (1) IPA and Section 8-103 programs have to be tracked separately by the utility; (2) IPA and Section 8-103 budgets have to be kept separate; (3) IPA and Section 8-103 program savings have to be determined and claimed separately; (4) pay-for-performance is a desired contracting mechanism for IPA programs (but not Section 8-103 programs); (5) utilities have no penalties for not achieving IPA savings (while there are penalties for not achieving Section 8-103 savings); (6) expanded IPA programs should participate in the IPA bidding process; and (7) funds approved pursuant to Section 16-111.5B cannot be spent on energy efficiency programs that were not approved in the procurement plan docket. AIC believes this separateness prevents the expansion of Section 8-103 programs into and overlapping the IPA portfolio when the utility does not have approved Section 8-103 programs. AIC also believes it is notable that the utilities submitted programs, including Multifamily, Specialty Lighting, and All Electric Homes, by separating them into different segments and expanding them in a larger volume than previously implemented, even if specific programs did not overlap. (AIC Response at 11-12)

AIC notes CUB joins the AG's argument that, during transition years, a utility should include in the RFP process requests for bids that "expand" Section 8-103 programs even though the Commission would not yet have approved any such programs for the upcoming procurement year. AIC says the IPA similarly states in its Response that utilities have the ability to propose expansions of Section 8-103 programs in transition years. AIC claims neither the IPA, the AG, nor CUB has adequately addressed the points raised by AIC in its Response: (1) it is not a fair or prudent assumption that a utility's initially filed plan will be accepted by the Commission without change, particularly in light of the fact that AIC's Plan 2 was not finalized until after the Final Order issued in Docket No. 10-0568; (2) both utilities' complied with the law with their respective submissions to the IPA, which AIC says was again confirmed by the IPA in its Response; and (3) the consensus items from the IPA workshop establish that programs administered pursuant to Sections 8-103 and 16-111.5B must be bid, implemented and managed separately. For all of these reasons, AIC insists it is not an appropriate use of utility, third-party vendor, IPA or Commission resources to conduct, participate in, and/or review the results of an RFP process that was premised, in part, on an assumption that the Commission would, at a later date, approve certain programs being reviewed and evaluated for approval under Section 8-103. AIC also believes it would seem equally inappropriate to require these parties to incur the additional costs to address any issues that would arise if that assumption proved incorrect and the bids and submissions were rendered unreliable (due to a change in cost-effectiveness results or otherwise). AIC also believes the Commission should not be asked to “pre-approve” programs that are a part of a utility’s Section 8-103 plan in the IPA procurement plan approval dockets when the PUA provides a separate process for such review and approval. (AIC Reply at 7-8)

AIC notes the AG states that it hopes that the IPA, DCEO and the utilities can craft an amendment to the Plan that permits Commission approval of cost-effective DCEO programs in the 2014 IPA Plan, as well as in future annual procurements. AIC says it is open to working with the IPA and DCEO to determine how DCEO programs may be incorporated into the 2014 IPA Plan, as well as in future annual procurements. As in Section 8-103, AIC maintains that it should not be held responsible for the achievement of any energy savings targets associated with DCEO programs. (AIC Response at 12)

According to AIC, it does not appear to be appropriate to include DCEO programs in the IPA Plan at this juncture. AIC says it has not vetted the information that would be submitted by DCEO and could not comment on whether the information is correct or cost-effective. AIC also notes that the law requires that the utilities – not DCEO – submit load forecasts and energy efficiency analyses to the IPA. AIC says while it issued an RFP for programs to include in its July 15 submission, DCEO did not respond. AIC analyzed the RFP responses it did receive, and submitted them to the IPA in compliance with the law. AIC states while it remains committed to working with DCEO so it can participate next year in a way that complies with the law, the AG’s recommendation that DCEO participate in this year’s Plan should not be followed. (AIC Response at 12-13)

AIC says ComEd appears to support allowing DCEO to participate as long as it does so through the third-party RFP process set forth in the PUA. AIC believes DCEO participation through the RFP process is not appropriate at this time, as there remain unresolved issues, including statutory limitations and other challenges like contracting. (AIC Reply at 8)

AIC agrees to work with interested parties to resolve these issues, if possible, and to work with parties on appropriate legislative changes. AIC recommends that the Commission defer ruling on how DCEO should participate, and if appropriate, order a workshop process to investigate how DCEO could participate in the RFP process (the IPA’s second option, and the option supported by ComEd). (AIC Reply at 8-9)

AIC recommends the Commission reject the AG’s argument that not all duplicative programs should be excluded from the IPA Plan. The AG argues that duplication of energy efficiency programs should not be viewed as an insurmountable problem because there are some programs that can be duplicated by segmenting the market by vendor. AIC notes the AG argues small business direct install programs can be offered by multiple vendors without a problem because the core utility programs will likely only reach a few percent of the eligible population in any given year, and multiple vendors offering similar or even exactly duplicative programs can be handled efficiently and allow for capture of a greater share of the eligible population each year. In AIC's view, the AG overlooks the fact that during cost effectiveness evaluation, a program is evaluated in isolation, and thus it would not be possible to determine whether duplicating the program, even if duplicated in different market segments, would cause the program to be non-cost effective. AIC believes the AG also overlooks the risk of inefficiency and market confusion. AIC says each program will have different offerings, processes, and incentives. According to AIC, customers will typically refer to the utility program and assume they are eligible for the utility incentives, even when this is not the case. AIC suggests confused customers will likely go to the utility's website, call the utility regarding participation in the program, and complete the utility's program application, resulting in significant inefficiency and frustration. Allowing a duplicate program would, in AIC's view, increase the risk for the utilities and create vast market confusion. AIC maintains the Commission should continue to permit the utilities to use their discretion to exclude duplicative programs. (AIC Response at 13-14)

AIC argues, for the same reason, the existing Section 16-111.5B Comment process before the Commission is not the appropriate forum for assessing the viability and desirability of proposed programs. AIC says each proposed program is evaluated in isolation before the Commission, and thus the evaluation does not capture the negative effects on cost-effectiveness when there are duplicative programs. AIC insists the utilities should be permitted to exclude duplicative programs in their submissions. (AIC Response at 14)

AIC notes the AG recommends that all RFPs that pass the total resource cost test should be submitted to the IPA and the utilities should explain fully why they believe a particular program is duplicative or competing. AIC notes that it already does this, and thus would not object to including such a requirement for next year's IPA Plan, as long as the IPA Plan also specifies that utilities are entitled to screen out programs that are duplicative/competing. In the event a competing program is approved, however, AIC asserts the competitive program's savings should be reduced by the amount of the other competitive program's savings and it must be realized that the utility-provided TRC analysis may no longer be accurate (because the TRC test, which contains multiple factors, assumes the program is implemented in isolation). (AIC Response at 14) AIC believes utilities should be permitted to recalculate the TRC value for each competing/duplicative program to account for the fact that a program would no longer be implemented in isolation. (AIC Reply at 9)

In response to the IPA's request for input on the test for "competing," AIC indicates it does not object to using the seven factor test for determining whether a program is "competing" (IPA Plan's five factors plus ComEd's additional two factors). (AIC Reply at 10)

AIC agrees with the IPA's position that the utilities may exclude duplicative/competing programs from the energy savings and load forecast numbers initially presented. AIC further agrees to continue providing to the IPA all bids received in response to the RFP process for ultimate determination by the Commission as to whether a program is duplicative or competing. To the extent the AG and CUB want the utilities to provide all bids received, AIC agrees, as that is a practice it has already undertaken. To the extent the AG and CUB's positions are inconsistent with the IPA's position, and they would like the utilities to include duplicative/competing programs in the utilities' program submissions to the IPA (e.g., those programs that should be included with the Plan), AIC disagrees with the AG and CUB. AIC maintains that allowing duplicative/competing programs would increase the risk for utilities and create market confusion. AIC agrees with ComEd that a utility can and should exclude duplicative/competing programs from its 16-111.5B proposal to the IPA. (AIC Reply at 9)

In its Reply Brief on Exceptions, AIC indicates it supports the Proposed Order as written, should the Commission adopt any proposed language accepting the seven factors regarding duplicative and competing programs, AIC believes the Commission should also include the certain other language in the Order. Specifically, AIC wants the Order to state in the event the Commission approves a competitive or duplicative program for inclusion in an IPA Plan, such approval would be conditional on the results of a revised TRC analysis and confirmation from the vendor of continued interest in implementing the program. AIC also wants the Order to state the affected utility would be ordered to provide a revised TRC analysis and contact the vendor to confirm continued interest in implementing the program. AIC says the result of the revised analysis, as well as the vendor's written response, shall be filed in the affected IPA procurement docket within 60 days after the order approving the program. AIC also states in the event the revised analysis concludes that the duplicative or competitive program is cost-ineffective or that the vendor has withdrawn its bid, the program should not be included in the Plan and the utility would not be obligated to contract for the duplicative or competitive program. (AIC RBOE at 14)

The AG objects to AIC's submittal of one year of savings and costs as inconsistent with Section 16-111.5B's stated goal of capturing all achievable energy efficiency. AIC claims that contrary to the AG's argument, while utilities have the option of submitting more than one year of data, nothing in Section 16-111.5B indicates that the utility should or must submit more than one year of savings and costs. AIC says Section 16-111.5B requires each utility to annually provide an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan. As part of this assessment, AIC says each utility must provide an energy savings goal, expressed in megawatt-hours, for the year in which the measures will be implemented. AIC believes that because the AG's position appears inconsistent with the statute, and AIC's submission of one year of savings and costs complies with the law, the Commission should disregard the AG's objection to AIC's submission of only one year of savings and costs. AIC says it reserves its right to submit multiple years of programs in the future as an option, if appropriate. (AIC Response at 14-15)

AIC notes the AG refers to the statement on page 86 of the IPA Plan that AIC's decision to submit one year of savings and costs resulted in a smaller MWh efficiency goal than that of the previous year. AIC claims the alleged correlation between AIC's submission and the smaller goal, however, is inaccurate. AIC claims its lower goal was based on the responses to the RFP process. (AIC Response at 15)

AIC objects to the AG's recommendations regarding oversight of the evaluation process. AIC believes the AG inappropriately ties pay-for-performance contracting with the evaluation of IPA programs. AIC says its agreement to perform evaluations should not be interpreted as an agreement to a requirement of using pay-for-performance contracting. AIC believes utilities should have the option, not the requirement, of using pay-for-performance contracting. (AIC Response at 15-16)

AIC claims the AG also asks that, if the Commission does not intend to assume oversight of the evaluation process, the Commission enter an order that the utilities will assume responsibility for the evaluation and successful delivery of these programs. AIC says it always implements programs with the goal of succeeding, but it would be unfair to require a utility to assume responsibility for the success of independent bidders who were not recommended by the utility, but rather who responded to the RFP issued by AIC and became part of the submission to the IPA, as required by law. (AIC Response at 16)

AIC also asserts the AG's position with respect to oversight of the evaluation process is inconsistent. AIC says while the AG requests that the utilities assume responsibility for an evaluation process that is consistent with the evaluation practices followed under Section 8-103, the AG also recommends that evaluation plans could be developed in workshops or the Stakeholder Advisory Group. AIC states that per the AIC Plan 2 order Section 8-103 evaluation workplans do not include SAG approval – the Commission ordered that Staff, not the SAG, approves the evaluation, measurement and verification ("EMV") work plans. According to AIC, the SAG does not presently have a formal role in the Section 8-103 evaluation process. AIC says that regardless, it would welcome and would agree to SAG participation in the evaluation process. (AIC Response at 16)

AIC does not object to the IPA's declining oversight over the programs. AIC argues that for the reasons set forth in its Response, the Commission should not include the AG's requested language regarding oversight in the Final Order because it is unnecessary and inconsistent. AIC says the Commission already has oversight over the utilities' implementation of energy efficiency programs and has also already ordered Staff, and not the utilities, to approve evaluation workplans. (AIC Reply at 10-11)

AIC indicates it agrees with and supports ComEd's argument that Section 16-111.5B does not provide for the IPA to pursue the goal of achieving all cost savings identified in the potential study. Accordingly, AIC requests that Section 7.1.3.1, "Feedback Mechanisms," of the proposed IPA Plan be removed, as shown in the redline provided by ComEd as Appendix A to its Objections. (AIC Response at 17)

AIC also agrees that the issue raised by ComEd – that there is no law that suggests DCEO should be treated differently than any other third-party vendor in the

16-111.5B procurement process – is one of the issues that must be resolved. Nonetheless, AIC is open to working with the IPA and DCEO to determine how DCEO can participate in accordance with the law, as long as DCEO remains responsible for the achievement of any energy savings targets associated with DCEO programs. (AIC Response at 17)

According to AIC, ComEd agrees that pay-for-performance language should be a standardized contract term, but it points out that the Plan's proposal with respect to contract principles is vague as it is unclear what precisely the IPA is asking the Commission to do. (Id., citing ComEd Objections at 7) AIC agrees that the Plan is vague with respect to how the utilities should incorporate pay-for-performance language into the contracts of successful bidders. AIC requests that the use of pay-for-performance contracting mechanisms be optional and that further clarity be provided on this issue. (AIC Response at 17)

AIC notes the AG argues the Commission should require the utilities to consult SAG members both prior to the issuance of the RFPs and after RFPs are received. In AIC's view, such a requirement is unnecessary, unwarranted and would add another step in a time-sensitive process. AIC says it already regularly meets with participating SAG members regarding various aspects of energy efficiency, including issues that pertain to the programs offered under Sections 8-103 and 16-111.5B. AIC says neither the AG nor any other party has lodged any complaints that a utility has denied any interested SAG member access to information regarding the RFP process or the proposals. AIC claims the AG's proposal would be unworkable to implement and difficult to establish compliance with. AIC says the SAG remains an informal group that has no limit or bar to its membership (including to vendors for whom the RFP process would be meant to apply). AIC also says SAG members participate as much or as little as they choose. Under such circumstances, AIC believes it is unclear how a utility could establish it has complied with a Commission order to "consult" with SAG members who may seek to influence the RFP process to the benefit of the vendors or who do not wish to participate in such consultation. AIC also asserts Section 16-111.5B of the PUA makes no reference to SAG involvement in the RFP process. Instead, AIC states the PUA places the responsibility on the utility to prepare an assessment and provide it to the IPA, even though AIC has in the past discussed with interested SAG members issues pertaining to the IPA portfolio. AIC argues to now add a requirement to "consult" with the SAG when there has been no factual or legal showing that such an additional step in the process is either necessary or warranted would be improper. Rather, AIC claims such a requirement would only detract resources that could otherwise be spent fulfilling a utility's statutory obligations under the PUA. AIC believes the AG's request that the Commission should order the utilities to "consult" with the SAG members should be denied. (AIC Reply at 4-5)

AIC also notes CUB makes two proposals with respect to the potential studies for identifying cost-effective energy efficiency. The first is that the Commission should require the utilities to release potential studies in the fall prior to the release of the Section 8-103 three-year plans. The second is that the Commission should require the utilities to design potential studies to account for the programs that could be offered pursuant to both Section 8-103 and Section 16-111.5B. AIC contends neither proposal should be accepted. (AIC Reply at 5-6)

According to AIC, CUB's proposal to require release of potential studies in the fall prior to the release of the Section 8-103 plans ignores the realities of resource limits and time constraints inherent in conducting potential studies. AIC claims a comprehensive potential study for Illinois takes a minimum of 12 months. AIC says under Section 8-103, an electric utility must file its three-year plan no later than September 30th, which means the potential study must be started by the summer of the preceding year. AIC asserts any request for proposals that would be considered for inclusion in a potential study must go out 6 months preceding the start of the potential study, meaning the RFPs go out approximately 1.5 years before the study can be issued. AIC contends CUB's proposal to speed up the issuance of the potential study by a year would result in pushing all of this back even further, resulting in an unnecessary compromise in data integrity (e.g., the utility would not be using the most updated EMV results, baseline forecasts, NTG values). AIC argues CUB has presented no evidence that such a compromise is needed or warranted and, accordingly, the request to speed up the potential study should be denied. (AIC Reply at 6)

AIC believes CUB's proposal to require utilities to design potential studies to account for the programs that could be offered pursuant to both Section 8-103 and Section 16-111.5B is unnecessary. AIC's potential study, which it says was attached to the IPA Plan itself in this docket, reflects an assessment of AIC's service-wide territory potential and was not limited to just Section 8-103 or Section 16-111.5B. AIC asserts the study reflects AIC's customers' willingness to participate in AIC's programs as a whole. Other than noting its own lack of clarity on this topic, AIC argues CUB has not pointed to nor cited any evidence to the contrary. AIC believes this proposal should not be adopted. (AIC Reply at 6)

In its RBOE, AIC provides language for the order in the event the Commission determines a workshop process is warranted on finding ways for DCEO to participate in next year's plan. (AIC RBOE at 5-9)

3. The AG's Position

The IPA defines "feedback loop" as a process or processes that ensures that energy efficiency opportunities identified in the utility's required potential study that are not met by the third-party RFP process are somehow filled. The IPA notes that it is concerned that the combination of the new programs and expanded utility programs may not fully meet the outer boundaries of the potential study in any given year.

The AG shares the concern raised by the IPA, and believes that the key to maximizing cost-effective, achievable efficiency lies in the expansion of programs authorized under Section 8-103 of the PUA. The AG states while the IPA appropriately highlights the difficulty of approving Section 8-103 program expansions in years when the Section 8-103 programs are up for review for a new three-year cycle, and Commission approval of said programs has not yet occurred, the problem is not insurmountable, even absent a statutory change in the timing of the IPA and Section 8-103 filing deadlines. When the utilities prepare RFPs and submit by July 15 each year their assessments and recommendations to the IPA for achievable, cost-effective Section 16-111.5B efficiency programs, the AG says they have undoubtedly also prepared in those years when required to do so, their draft plans for Section 8-103 three-year programs, which are filed by September 1. According to the AG, the utilities are more than likely aware of which programs will be the centerpieces of their Section 8-103 program portfolios when they submit their recommendations to the IPA for achievable, cost-effective efficiency programs. (AG Objections at 2-3)

The AG suggests, given that reality, there is no reason utilities should not be bidding into the IPA portfolio planned expansions of proposed Section 8-103 programs that they have concluded are cost-effective and are likewise proposing be approved by the Commission in the Section 8-103 dockets. The AG believes the onus should be on the utilities to prepare their Section 16-111.5B IPA submissions in coordination with their planned Section 8-103 filings. The AG says approval of Section 8-103 programs occurs within 30 days of the Commission's final order in the IPA procurement docket. Prior to that approval, the AG suggests it will be clear to all interested parties whether challenges exist to a utility's proposed Section 8-103 efficiency portfolio. (AG Objections at 3)

According to the AG, in Docket No. 13-0498, AIC's three-year efficiency plan docket, Staff and intervenors are scheduled to submit direct testimony responding to the AIC filing by October 18, 2013. The AG says a Commission final order in the IPA Procurement Plan docket is not due until December 30, 2013. The AG believes including proposed expansions of planned Section 8-103 programs (subject to Commission approval) is an easy, effective way to help ensure that achievable, cost-effective efficiency is provided within a utility's service territory. The AG believes that it is up to the utilities to plan IPA procurement RFPs and Section 8-103 filings every three years so that maximum, cost-effective Section 8-103 programs expansions can be included in their July 15 submissions to the IPA. (AG Objections at 3)

The AG suggests that inclusion of expansions of existing or proposed Section 8-103 programs would help ensure that utilities and the IPA identify all cost-effective opportunities for efficiency available within service territories. The AG believes it is reasonable to assume that expansions of existing or proposed Section 8-103 programs will be highly cost-effective, given the ability of utilities to oversee and manage the delivery of these program expansions. According to the AG, the Commission's final order in this docket should instruct the utilities to include proposals for expansions of Section 8-103 programs that will be proposed by the utilities in their September 1 three-year filings when it submits proposed programs to the IPA. (AG Objections at 3-4)

The AG says another issue raised by the IPA for Commission resolution is inextricably linked to the first identified issue: addressing the uncertainty surrounding the transition year wherein the Section 8-103 programs for the following three years are not yet approved. The AG says its position is essentially the same on the two issues. (AG Objections at 4)

Another issue identified by the IPA for Commission resolution is the lack of participation of DCEO in the IPA's procurement of incremental energy efficiency pursuant to Section 16-111.5B of the PUA. The AG says that as noted by the IPA, there was consensus in the Commission-directed workshop process that cost-effective DCEO programs should be included in the procurement of energy efficiency for the IPA's annual portfolio. The IPA Plan notes that DCEO did not participate in the utility-run RFP process, but rather submitted its proposed cost-effective efficiency programs to the IPA directly. The IPA states that it "determined that it could not include the programs proposed by DCEO pursuant to Section 16-111.5B at this time because DCEO is not a utility as the term is used in Sections 16-111.5 and 16-111.5B." The AG says this was the same perceived problem that precluded inclusion of DCEO programs in last year's IPA procurement plan. Notwithstanding these perceived limitations, the IPA states that "the programs proposed by DCEO have great potential value…, especially to low income customers…", and included DCEO's submission in this docket's record as Appendix H. The IPA further notes it would follow any Commission order that included DCEO programs in this year's procurement and prospectively. (Id. at 4-5)

The AG believes it is important to incorporate DCEO programs within the Plan, given that DCEO is the entity that oversees the delivery of Section 8-103 programs targeted to low income customers. The AG believes existing DCEO low income Section 8-103 programs are ripe for expansion and represent significant cost-effective opportunities to both increase the delivery of overall achievable energy efficiency, while also providing needed benefits to low income electric utility customers who often struggle to pay utility bills. The IPA Plan notes that it "understands that DCEO may have some administrative limitations regarding contracting that could preclude that option in future years." The AG requests that the Commission take evidence or comments on the bidding difficulties that have prevented DCEO's participation in IPA Plans to date. Once a clearer understanding of these contracting difficulties is presented, it is the AG's hope that the IPA, DCEO and the utilities can craft an amendment to the Plan that permits Commission approval of cost-effective DCEO programs in the 2014 IPA Plan, as well as in future annual procurements. (AG Objections at 5)

Two additional issues raised by the IPA for Commission resolution revolve around competition between incumbent utility programs and third-party RFP programs. The first question raised is what it means for a third-party bidder's proposed program to be "competing" with or "duplicative" of a utility program. The second issue is the authority of the Commission to reject a third-party bidder's program that is "competing" with or "duplicative" of a utility's program but which otherwise passes the standard for cost-effectiveness. (AG Objections at 5-6)

The AG suggests a review of the relevant statutory language should be a guide for the consideration of these issues. Section 16-111.5B(a)(2) and (a)(3)(c) provides that IPA assessments of assessments of cost-effective energy efficiency potential should include an assessment of:

> (2) …opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of this Act or to implement additional cost-effective energy efficiency programs or measures.

Section 16-111.5(a)(3)(c) requires utilities to include in their submissions to the IPA of potential, cost-effective energy efficiency programs, proposals for:

> …cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act and that would be offered to all retail customers whose electric service has not been declared competitive under Section 16-113 of this Act and who are eligible to purchase power and energy from the utility under fixed-price bundled service tariffs, regardless of whether such customers actually do purchase such power and energy from the utility.

According to the AG, the language referencing opportunities to "expand" the Section 8-103 programs, offer "additional" and "incremental" programs or measures supports the IPA concern about including programs perceived to be in competition with Section 8-103 programs. (AG Objections at 6)

That being said, the AG claims establishing whether a program is indeed duplicative or competitive may be obvious in certain situations and less than obvious in others. According to the AG, the IPA Plan seems to agree, as it recommends "continuing the process followed this year that does not set a specific standard." The AG states that the existing Section 16-111.5B Comment process before the Commission provides an appropriate forum for assessing competitive programs and their viability and desirability. The AG says it is important to exclude programs that might create an environment in which multiple market actors are competing for the same customers/projects and offering the same efficiency services. The AG believes it is reasonable to assume that such an environment would create inefficiencies, increase administrative costs, and could create perverse incentives that are not in ratepayers' interests. (AG Objections at 7)

The AG concludes that the Commission should have the final word on assessing whether a cost-effective program is indeed competitive, duplicative and therefore, disruptive to existing Section 8-103 efficiency markets. The AG believes it is important that individual utilities not assume the role of judge and jury when it comes to assessing whether a program is truly duplicative, competitive and likely to disrupt the existing Section 8-103 efficiency market. In order to ensure that utilities alone have not pre-judged whether a program was competing or duplicative, however, the AG says all RFPs that pass the total resource cost test should be submitted to the IPA for consideration of inclusion in the proposed procurement portfolio. The AG suggests in the IPA submittal, the utilities should explain fully why they believe a particular program is duplicative or competing, including a description of specific aspects of the program that are deemed problematic so that the IPA could determine in its Plan possible steps to eliminate problematic aspects of a particular program. (AG Objections at 7)

According to the AG, programs that are "duplicative" or "competing" may or may not be problematic depending on the type of program and its target market. The AG says the reasons to avoid duplication/competition are to avoid unnecessary confusion in the market or unnecessary duplication of administrative and other services that increase costs or decrease efficiency. The AG also says the extent to which these are issues will depend heavily on the types of programs and markets involved. (AG Objections at 7-8)

The AG suggests a duplicative broad-based upstream program such as residential CFL buy downs would be problematic. The AG claims this is because this program by its nature works upstream from the customer and therefore depends on very broad-based advertising and overall contracts with major retailers throughout the State. In this instance, the AG says any duplication would by nature create competing broad-based advertising and competing for the same retailers and shelf space, competing point of purchase displays, duplicative administrative tracking and evaluation, etc. The AG asserts that some programs can easily duplicate by segmenting the market by vendor. The AG says small business direct install programs typically capturing participants through direct in-person marketing, and delivery of audits and measure installation. The AG argues because the core utility programs will likely only reach a few percent of the eligible population in any given year, multiple vendors offering similar or even exactly duplicative programs can be handled efficiently and allow for capture of a greater share of the eligible population each year. According to the AG, competing vendors can be assigned discrete and mutually exclusive customer lists from which to market. Similarly, the AG says they can be each given separate mutually exclusive geographic territories to market to, or mutually exclusive customer segments. In these cases, the AG believes duplication should not be viewed as an insurmountable problem. Rather, the AG suggests the utilities should submit to the Commission their issues, potential concerns, and suggested remedies where feasible to ensure smooth delivery of duplicative programs. (AG Objections at 8)

The AG says AIC's submission to the IPA contains programs and measures that were “expanded” from the Section 8-103 Plan by virtue of being removed from AIC's Section 8-103 three-year plan filing in Docket No. 13-0498. The IPA notes that AIC's submittal stated that it represents “one year of savings and costs,” but reserves the right to submit multiple years of programs and related savings in future submissions. The IPA observed that this decision resulted in a smaller MWh efficiency goal than that of the previous year. (AG Objections at 9)

The AG submits that such an exclusion is both unwise and inconsistent with Section 16-111.5B's stated goal of capturing all achievable energy efficiency. The AG contends that while the inconsistent filing deadlines of the IPA July 15 submission and the Section 8-103 submission are less than ideal, nothing prevents the utilities from proposing those programs that are ripe for expansion in their respective Section 8-103 filings. The AG maintains that the utilities are more than likely aware of which programs will be the centerpieces of their Section 8-103 program portfolios when they submit their recommendations to the IPA for achievable, cost-effective efficiency programs. In the AG's view, simply because they have yet to receive formal Commission approval of certain Section 8-103 programs is not reason to exclude them as proposals in an IPA portfolio. (AG Objections at 9)

In order to maximize successful expansion of programs, the AG maintains the onus should be on the utilities to prepare their Section 16-111.5B IPA submissions in coordination with their planned Section 8-103 filings. In that regard, the AG believes expansions of proposed Section 8-103 programs are no different than any utility-proposed IPA program that has yet to receive Commission approval. According to the AG, including proposed expansions of planned Section 8-103 programs is an easy, effective way to help ensure that achievable, cost-effective efficiency is provided within a utility's service territory. Absent statutory modification of filing deadlines, the AG believes that it is up to the utilities to plan IPA procurement RFPs and Section 8-103 filings every three years so that maximum, cost-effective Section 8-103 programs expansions can be included in their July 15 submissions to the IPA. The AG also notes that ComEd proposed both multi-year and single-year programs. The AG says AIC was alone in assuming that three-year offerings were somehow prohibited this year by the differing IPA and Section 8-103 timelines. (AG Objections at 9-10)

The IPA notes in its description of the ComEd submission that the utility excluded from its submission of recommended programs six programs that ComEd considered duplicative. The AG says five of these six programs passed the TRC test. (AG Objections at 10)

The AG repeats that Section 16-111.5B makes clear that both the IPA, in its submission to the Commission, and the Commission as final arbiter, should be presented with all programs that pass the TRC for purposes of evaluating what programs should be included within the IPA's procurement portfolio. The AG says the Commission has not provided any specific guidance on what constitutes "duplicative" or "competing" programs, and whether inclusion of such programs in an IPA portfolio would be disruptive to the existing ratepayer-funded energy efficiency market. (Id.)

According to the AG, ComEd's stated rationale for excluding a program it deemed duplicative also highlights the inherent contradiction of excluding duplicative or competing programs that will end before the 2014 procurement takes place, but not including expansions of programs that have yet to be formally approved by the Commission in Section 8-103 dockets, but are nevertheless being proposed by the utilities in those dockets. In the AG's view, this incongruity only highlights the need for utility submissions to include in their IPA filings some kind of proposed expansions of programs that they intend to offer under Section 8-103 of the Act. (AG Objections at 10-11)

The AG says one topic not specifically addressed in the draft IPA Plan is oversight and evaluation of Commission-approved IPA programs. It is unclear to the AG how IPA Procurement Plan energy efficiency programs are monitored and evaluated, if at all, as compared to the evaluation of Section 8-103 programs. While Section 16-111.5B(a)(6) lists evaluation costs as recoverable costs through the Section 8-103 rider charges, the AG says no clear roadmap exists for the evaluation of the IPA programs. (AG Objections at 11)

The AG notes that while the utilities are not subject to energy savings goals and penalties, as exists under Section 8-103 programs, ratepayers are nevertheless paying increased surcharges for the IPA programs. The AG states that while the utilities propose a pay-for-performance contract regime for IPA efficiency programs, further development of a record in this docket is necessary to provide the Commission with some explanation as to what role, if any, the IPA and the utilities plan to play in the IPA efficiency program evaluation process, and whether pay-for-performance contracts adequately protect ratepayer interests. The AG suggests if it does not intend to assume such an oversight role, then the IPA should request that the Commission enter an Order that makes clear that the utilities will assume responsibility for the evaluation and successful delivery of these programs, consistent with, to the extent practicable, the evaluation practices followed under Section 8-103 programs. The AG says specific evaluation plans could be developed in workshops or the Stakeholder Advisory Group, which currently assists in the development of Commission-approved evaluation parameters. (AG Objections at 11-12)

The AG notes that in its Objections to the IPA Plan, ComEd asserts that nowhere within Section 16-111.5B is it stated that it is the goal of that section to fully capture the potential of all achievable cost-effective savings. ComEd opines that the Commission's role in the IPA procurement approval process is limited to ensuring that the energy efficiency measures included in the plan capture all achievable cost savings. The AG asserts ComEd is wrong on these points. (AG Response at 5-6, citing ComEd Objections at 4)

According to the AG, Section 16-111.5B(a)(5) clearly states that in addition to the IPA including in its plan the measures that it determines are cost-effective, the Commission shall also approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of the PUA. The AG says Section 16-115.5B(a)(5) directs that each Illinois utility shall annually provide to the IPA assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan, including a comprehensive energy efficiency potential study for the utility's service territory that was completed within the past 3 years, along with its RFPs and bids. The AG insists the General Assembly has made clear its charge to the Commission to ensure that the IPA procurement plan, to the extent practicable, fully captures the potential for cost-effective energy efficiency programs. (AG Response at 6)

The AG believes IPA was right to request Commission guidance on the need for a “programmatic planning link” to accomplish the goal of fully capturing potential efficiency, contrary to ComEd’s view that such a section in the Plan should be deleted. The AG says to date, stakeholder guidance on both the RFP and RFP review process has been an informal, voluntary process. According to the AG, a Commission order that requires the utilities to consult Stakeholder Advisory Group members both prior to the issuance of RFPs and after RFPs are received, would be an important component to the IPA Plan. The AG suggests such consultation would likely minimize the number of objections to the energy efficiency portions of the IPA annual Procurement Plan and reduce litigation. In the AG's view, ComEd’s recommendation to delete this IPA request from Commission consideration should be rejected. (AG Response at 6-7)

The AG indicates that in a discussion about defining “competing” programs for purposes of excluding programs from IPA consideration, ComEd argues at page 7 of its Objections that the utility can and should exclude proposals that it deems are “competing” from inclusion in the IPA portfolio. The AG believes ComEd overstates its authority. (AG Response at 7)

According to the AG, Section 16-111.5B sets up a framework for Commission evaluation and approval of the IPA Procurement Plan, including energy efficiency programs – not ComEd’s or any other utility’s approval. The AG believes Section 16-111.5B makes clear that the electric utilities conducting the potential studies and the RFP process serve as the conduits of information for both the IPA, which is charged with putting together the Procurement Plan, and the Commission, which is charged with approving the Plan. The AG maintains the Commission should have the final word on assessing whether a cost-effective program is indeed competitive, duplicative and therefore, disruptive to existing Section 8-103 efficiency markets. The AG argues it is important that individual utilities not assume the role of judge and jury when it comes to assessing whether a program is duplicative, competitive and likely to disrupt the existing Section 8-103 efficiency market. (AG Response at 7)

The AG maintains in order to ensure that utilities alone have not pre-judged whether a program was competing or duplicative, all RFPs that pass the TRC test should be submitted to the IPA for consideration for inclusion in the proposed procurement portfolio. In the IPA submittal, the AG believes the utilities should explain fully why they believe a particular program is duplicative or competing, including a description of specific aspects of the program that are deemed problematic so that the IPA can determine in its Plan possible steps to eliminate problematic aspects of a particular program. The AG believes the Commission shall have final say as to whether a particular program should be included within the IPA Plan. (AG Response at 7-8)

4. The IPA's Position

The IPA raises four “policy” issues in its Plan and subsequent pleadings. According to the IPA, the four issues are: (1) the lack of a “feedback loop” between third-party bids and the potential study; (2) how to expand programs pursuant to Section 8-103 utility plans in years where the three-year plan is being litigated during the pendency of the IPA Procurement Plan approval docket; (3) DCEO participation; and (4) how to deal with “duplicative” and “competing” third-party bids. The IPA separately introduces each of these items, although in its Response and Reply it considered the first and second policy issues together, abandoning a formal feedback loop.

With regard to the feedback loop, in the draft Procurement Plan, the IPA pointed out tension between the structure for the development by the utilities of programs for consideration of approval under Section 16-111.5B and the Commission’s standard for approval of programs under that Section. (IPA Plan at 82-83)The IPA says the tension specifically related to how fully capturing the potential for all achievable cost-effective savings, to the extent practicable is possible if the results of the utility-run RFP required by Section 16-111.5B(a)(3) do not cover the universe of efficiency identified in the potential study required by Section 16-111.5B(a)(3)(A). Although the IPA stated that it believes that the utilities’ submissions for this procurement cycle fully complied with legal requirements, the IPA believed that the tension warranted further discussion. (IPA Response at 11-12)

The IPA notes both the AG and ComEd believed that satisfaction of the statutory goal was possible under the current legal framework, although based on slightly different analysis. The IPA says ComEd and the AG both argued that improvements in the Section 16-111.5B(a)(3) utility-run RFPs are the key to achieving the goals of all achievable cost-effective energy efficiency. Also, both interpret “fully captur[ing] the potential of all achievable cost-effective” energy efficiency as being based on well-run RFPs (and, in the AG's case, expanding Section 8-103 programs) rather than fulfillment of the outer limit of the utility potential study. The IPA stresses its view that this will be an iterative process, given several criticisms of the utility RFPs from Comments that should be addressed in the RFP development process. (IPA Response at 12)

The IPA believes the positions of ComEd and the AG are reasonable to the extent that they coincide, and further believes that prudent expansion of Section 8-103 programs is also a reasonable approach and a more formal feedback loop process is not required. However, the IPA says an explicit ruling from the Commission about improvement to the RFP process would aid all parties. The IPA concludes that developing consensus as a first step toward legislative change is not necessary. (IPA Response at 12) The IPA continues believe that “prudent expansion” of Section 8-103 programs is a “reasonable approach,” but cautions against creating a requirement that utilities must expand all Section 8-103 programs - especially programs that have not yet been established as effective. (IPA Reply at 9)

With regard to the Section 8-103 plan year issue, in the Draft Procurement Plan, the IPA noted that Section 16-111.5B requires consideration of "new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act." (IPA Plan at 83) The IPA posited that every three years (including this year), the Procurement Plan must consider such an expansion at a time when the Section 8-103 plan has yet to be approved. The IPA considers this problem in two ways. The IPA says first is the resolution for this year, where – as AIC points out – AIC and ComEd have come up with statutorily-compliant solutions for this year's plan. The IPA has correspondingly recommended that AIC and ComEd's Section 16-111.5B programs be approved, subject to certain modifications. (IPA Response at 12-13)

The IPA also sees a longer-term issue, namely the stakeholders' ability to ensure that the Commission has a suite of energy efficiency options to approve under Section 16-111.5B plan every third year that achieves the statutory goal of "fully captur[ing] the potential for all achievable cost-effective savings, to the extent practicable." The IPA says in other words, ensure that the plans that are released every third year with Section 8-103 timing issues achieve the statutory goal equally well as the other two years. (IPA Response at 13)

The IPA notes the AG argued that the utilities have the ability to propose expansions of programs that the utilities include in their respective proposed (but not yet approved) Section 8-103 plans. The IPA agrees with this approach, in fact, it recommended conditional approval for an AIC program that relied on participation of Nicor through Nicor's proposed Section 8-103 plan. To the extent that stakeholders are satisfied that additional changes are not needed to satisfy the requirements of Section 16-111.5B(a)(5) in Section 8-103 plan approval years, the IPA is satisfied that no legislative change is needed. (IPA Response at 13)

With regard to DCEO participation, in the Draft Procurement Plan, the IPA identified a consensus among parties that DCEO should participate somehow in the Section 16-111.5B procurement process, but that there was no consensus as to how DCEO should participate. The IPA understands that including DCEO-proposed programs furthers the statutory goal of including all attainable cost-effective energy efficiency. Based on the Objections of parties, the IPA says there are three main options for DCEO participation and without further input from DCEO it is not clear which is the best option. (IPA Response at 14)

According to the IPA, the first option is allowing DCEO to follow the steps in Section 16-111.5B as if it was a "utility." The IPA says DCEO did not file Objections, but did provide the IPA with documentation designed to satisfy the requirements for utilities under Section 16-111.5B. The IPA included one of these documents in the Draft Procurement Plan as Appendix H, which DCEO provided as part of its pre-filing Comments. (IPA Response at 14)

To the extent that the Commission holds that DCEO is a "utility" pursuant to Section 16-111.5B, the IPA will going forward provide the same analysis to timely filed DCEO-provided energy efficiency programs. The IPA notes Section 16-111.5B(a)(3) states in part:

> In addition to the information provided pursuant to paragraph (1) of subsection (d) of Section 16-111.5 of this Act, **each Illinois utility procuring power pursuant to that Section** shall annually provide to the Illinois Power Agency by July 15 of each year, . . . an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan. (emphasis added)

The IPA says whatever the interpretation of "utility" in other sections, the requirements of Section 16-111.5B are limited to utilities for which the IPA procures power. To the knowledge of the IPA, it does not procure power on behalf of DCEO. ComEd provided additional arguments based on statutory construction that arrive at the same conclusion. (IPA Response at 14-15, citing ComEd Objections at 4-6.) As a result, although the IPA would follow a Commission Order to treat DCEO as a utility, the IPA does not believe this is the correct reading of the statute.

The second option, the IPA states, is for DCEO to participate in utility RFP processes required by Section 16-111.5B(a)(3). The IPA identified this option in the Procurement Plan for future years – the RFP for the present Procurement Plan is long past – with the caveat that DCEO might have administrative and legal barriers to participating. The IPA says the AG, AIC, and ComEd all note that this approach is available, and both the AG and AIC request further investigation into the barriers DCEO faces (if any) under that structure. Although DCEO has not had an opportunity to provide more information about barriers in this docket, the IPA hopes that DCEO can provide additional insight. Unless and until the IPA receives more information from DCEO, the IPA does not know whether this is a feasible approach and thus cannot recommend for or against it. (IPA Response at 15)

According to the IPA, the third option is to build consensus toward a legislative change that more clearly defines DCEO's proper role. The IPA is cognizant that legislative change is difficult and unpredictable, but depending on the barriers that DCEO identifies with the second option above, it may be the only feasible option. If the Commission finds that there is no feasible way for DCEO to participate in Section 16-111.5B under current law, the IPA recommends convening a working group to identify statutory and technical issues that ideally would develop and present consensus bill language to the General Assembly. (IPA Response at 15-16)

In its Reply to Responses, the IPA notes DCEO does not procure power pursuant to Section 16-111.5. In fact, the IPA says given the definition of "utilities" that shall or may participate in the IPA procurement process, DCEO would not be eligible to participate as a "utility" in the Section 16-111.5 procurement process. (IPA Reply at 9-10)

Nevertheless, the IPA does agree that including cost-effective energy efficiency programs for low income customers is an important policy goal. The IPA urges DCEO to provide additional information to help the Commission and stakeholders understand the barriers to DCEO participation in the utility RFP process. (IPA Reply at 10)

With regard to how to handle "duplicative" and "competing" programs, the IPA says that there is a consensus among the parties that programs that are "duplicative" of or "competing" with preexisting utility programs should not be included in Section 16-111.5B expansions. As noted in the Draft Procurement Plan, the IPA's goal is to provide a standard by which: (1) the Commission can evaluate what "duplicative" and "competitive" mean, and (2) future bidders can use to target their bids. The IPA says the goal is to solicit better bids from third-party vendors by providing those vendors better tools to evaluate whether a program will be (or could be) excluded. (IPA Response at 16)

On Exceptions, the IPA further clarified that while the utilities may identify third-party programs (with a TRC greater than one) that would lessen the effectiveness of utility programs, the utilities do not have unilateral discretion to ignore those programs. However, the Commission may exercise its discretion in finding that "all achievable" and "to the extent practicable" is not satisfied if third-party programs would undermine the effectiveness of utility-run programs, thus endangering "cost-effective savings." (IPA Exceptions at 124)

Despite consensus that the concepts should exist, the IPA initially said there was disagreement on the exact definitions proposed by the IPA for duplicative and competing. ComEd supported both IPA definitions, although recommended adding two extra factors to the definition of competing. AIC did not object to the IPA definition of duplicative, but initially objected to the IPA definition of competing, although AIC agreed in its Reply. (AIC Reply at 10) The AG argues that the terms should not be used to unfairly exclude worthy programs.

Due to perceived confusion during Objections, the IPA offers a clarification regarding its proposed process for screening duplicative and competing programs. The IPA believes that utilities may review programs to determine whether one is duplicative or competing, and flag those programs in their respective submittals to the IPA pursuant to Section 16-111.5B(a)(3). The IPA proposes that the utilities may further exclude those programs from the energy savings and load forecast numbers initially presented. However, the IPA agrees with the AG that the Commission ultimately decides whether a program is duplicative or competing. To that end, the IPA says it will continue to request (as both utilities provided) the documentation for all responses to the utility RFPs so that the IPA may make an independent evaluation. The Draft IPA Plan also agrees with the AG that the definitions should not be bright line tests. The IPA claims the utilities will play an important role in identifying competing and duplicative programs for Commission consideration, but the IPA believes that the Commission should ultimately decide whether an individual program is competing or duplicative pursuant to adopted standards. (IPA Response at 17)

The IPA notes AIC raised concerns about the definition of competing, primarily on the basis that it could impose additional burdens on AIC. The IPA indicates it is sympathetic to AIC's concern that:

> Allowing different vendors to offer essentially the same program to different geographic or end-use segments is more complex and potentially disruptive to the market than implied by the Plan. This is especially true for programs that rely on mass-market communication channels, which could be negatively impacted by competing messages.
> (IPA Response at 17-18, citing AIC Objections at 11)

The IPA asserts finding the line between programs that negatively impact each other and programs that will not is exactly what the IPA is trying to do with the definition. To the extent it is not feasible to model the impact of the negative impact on TRCs, the IPA believes AIC's concerns are consistent with the spirit of the IPA's concerns. To the extent that AIC has a different test for the Commission to use for "competing" that better captures this impact, the IPA encourages AIC and other parties to modify or replace the IPA's proposal.

The IPA stresses the interplay between the AG's and AIC concerns. On one hand, the IPA says using the terms duplicative and competing to simply clear the field of any program remotely resembling a utility program is contrary to the statutory mandate of Section 16-111.5B of "fully captur[ing] the potential for all achievable cost-effective savings, to the extent practicable." On the other hand, the IPA says blind approval of programs that hinder each other (to the extent that one or both may no longer be cost-effective) is also inconsistent with the statutory mandate. The IPA proposed definitions – especially for "competing" – are designed to avoid future failures to fulfill statutory mandates that the AG and AIC respectively identify. (IPA Response at 18)

The IPA notes ComEd generally supported the IPA's proposed definitions, but recommended supplementing the definition of "competing" with two additional factors. Specifically, those factors - numbered to continue after the five factors the IPA proposed - are: "(6) the effect(s) on utility joint program coordination, and (7) impact on Section 8-103 EEPS portfolio performance." The IPA agrees that these are legitimate factors to consider as part of a multi-factor test. (IPA Response at 18)

Based on the Responses, particularly those provided by the AG, CUB, and AIC, the IPA wishes to further clarify its proposed procedure for addressing duplicative and competitive energy efficiency programs. The IPA proposes that the Commission approve the following procedure for dealing with duplicative or competitive programs, which was followed in the development of this Procurement Plan:

- The utilities receive and review the third-party RFP results, and determine which bids are, in the utility's estimation, duplicative or competing. The utilities are under no obligation to identify any programs in this manner.
- In the annual July 15 assessment submitted to the IPA, the utility may exclude programs it has determined are duplicative or competing from the estimated savings calculation (and associated adjustments to the load forecast). However, in their submittals to the IPA, the utilities must: (1) describe the duplicative or competing program; (2) explain why the utility believes it is competing or duplicative; and (3) provide the IPA with all of the underlying documents as it would for any other bid.
- The IPA will independently review all of the bids submitted by the utilities and determine which the IPA believes are duplicative or competing. The IPA will identify all programs to the Commission in its Procurement Plan filing, along with a recommendation that some programs should be discarded as duplicative or competing.
- The parties to the Procurement Plan approval litigation, including the IPA, may opine on whether a particular program is duplicative or competing, and the Commission will make the final determination. To the extent that a utility had previously determined that a program is duplicative or competing but the Commission disagrees, the utility will update the estimated energy savings and load forecast to reflect the readmission of the program.

(IPA Reply at 10-11)

The IPA wishes to highlight a few aspects of this procedure. First, the IPA says the utilities do not have the ability to prevent the Commission (or IPA) from independently assessing whether a program is competing or duplicative. In the IPA's view, the AG and CUB's concerns that the utilities will be able to unilaterally remove programs because they are duplicative or competing could not occur under the IPA's proposed structure. The IPA also says if a program is found to be duplicative or competing by whatever standard the Commission approves in the present docket, the Commission should remove it. The IPA claims this addresses AIC's concern that a duplicative or competing program (as found by the Commission) would somehow stay in the Procurement Plan. (IPA Reply at 11)

The IPA says as part of AIC's Section 16-111.5B submission to the IPA, the contractor running AIC's Small Business Direct Install ("SBDI") program sought a significant expansion of the program. (See Procurement Plan Appendix B at 11) In the Section 16-111.5B submission, the IPA says AIC recommended against the significant expansion, noting that:

> 2013 (Y6) is the first year AIC is implementing the SBDI program as approved in the 2013 IPA Plan. AIC considers it prudent and responsible to first assess and evaluate the performance of this program prior implementing it again on a larger scale. Alternatively, AIC is recommending that it is included in the 2014 IPA plan at the same level as approved in 2013.

In its August 15, 2013 Draft Plan for Comments, the IPA suggested consideration of the contractor's proposed expansion, which AIC opposed in Comments. In its Comments, the IPA says AIC argued that:

> Additionally, as referenced in regards to the [SBDI] Program, Ameren Illinois notes that . . . there remains considerable risk associated with management assessment during the ICC's review of the reconciliation of costs and revenues under the applicable cost-recovery mechanism.

The IPA indicates it responded to AIC's concerns in the Procurement Plan, recommending that AIC provide more information about the risks specific to SBDI before the IPA would alter its recommendation. (IPA Response at 19)

The IPA notes in Objections, AIC provided more detail about why it believed that it would not be prudent to significantly expand the program - specifically, because there are not yet verified results to determine whether the program is as effective as anticipated. In other words, the potential problem with SBDI expansion is about spending increased ratepayer money a program that is not yet proven, but will have the opportunity with the passage of time to produce evaluable results. The IPA says AIC then recommends that SBDI be approved at the "base level" of 30,179 MWh savings goal. (Id.)

The IPA indicates it appreciates the additional discussion in AIC's Objections and agrees with the concept that the Commission should exercise caution in expanding programs that have not demonstrated results when additional information is forthcoming. However, the IPA also notes that a delay creates additional lag in expanding what may eventually be proven to be an effective program. (IPA Response at 20)

Since the IPA filed its Response, AIC has informed the IPA that the vendor seeking the expansion of the SBDI program has in writing withdrawn its larger (73,435 MWh) expansion, but has reaffirmed its bid at AIC's "base level" expansion of a 30,179 MWh savings goal. The IPA has not reviewed the correspondence, but on the basis of AIC's representation, the IPA now recommends that the Commission approve the SBDI "base level" expansion. (AIC Reply at 12)

The IPA notes the AG raised an issue regarding oversight of Section 16-111.5B-approved programs after Commission approval. Specifically, the AG noted that:

> It is unclear how IPA Procurement Plan energy efficiency programs are monitored and evaluated, if at all, as compared to the evaluation of Section 8-103 programs. While Section 16-111.5B(a)(6) lists evaluation costs as recoverable costs through the Section 8-103 rider charges, no clear roadmap exists for the evaluation of the IPA programs.
> (IPA Response at 20, citing AG Objections at 11)

The AG further argues that the record in this docket should be developed to address this gap, and request that:

> If it [the IPA] does not intend to assume such an oversight role, then the IPA should request that the Commission enter an Order that makes clear that the Utilities will assume responsibility for the evaluation and successful delivery of these programs, consistent with, to the extent practicable, the evaluation practices followed under Section 8-103.

The IPA concurs with the AG that there is no clear delegation of oversight and evaluation for programs approved pursuant to Section 16-111.5B. The IPA also notes that subsection 16-111.5B(a)(6) lists "evaluation, measurement, and verification of services" as among the costs that the utilities are allowed to recover. However, the IPA does not believe it is an appropriate agency to exercise oversight over utilities. The IPA is primarily a planning and procurement agency without enforcement authority, and thus not naturally suited to an oversight role. The IPA agrees that oversight over utility activities regarding Section 16-111.5B-authorized programs is appropriate, but declines to insert itself into an inappropriate oversight role. (IPA Response at 20-21)

The IPA notes that AIC argued in its Response that pay-for-performance contracting for successful third-party bidders in the utility's energy efficiency RFP should be optional. The IPA believes that, as a general matter, versions of pay-for-performance contracts are highly appropriate in the Section 16-111.5B context, i.e. where utilities are not constrained by a minimum savings goal subject to significant penalties. The IPA has not reviewed all of the contracts the utilities have entered into with successful Section 16-111.5B RFP bidders, but understood that the majority (or all) such contracts were written in accordance with pay-for-performance principles. The IPA says workshops held by Staff further confirmed that even if pay-for-performance is not the legal requirement, it is the recommended practice. (IPA Reply at 12)

The IPA is not sure that this docket, particularly given the late stage of Objections in a time-constrained docket, is the appropriate venue for discussing the requirements for Section 16-111.5B third-party RFP-winner contracts. The IPA has already recommended, in lieu of a "feedback loop," that stakeholders work with utilities on the RFP language to address the significant concerns raised in Comments, some of which have been repeated or amplified in Responses. However, the IPA believes this is an important issue (even if the IPA is not responsible for oversight of the contracts' execution) that the IPA would like to see discussed among stakeholders before further Commission action. (IPA Reply at 13)

AIC argues that it is under no obligation to provide multiple years worth of savings goals in its submission to the IPA in response to an AG objection. Although the IPA believes that multi-year programs benefit from more upfront information, the IPA agrees with AIC that there is no legal obligation to provide multiple years of savings goals. (IPA Reply at 11-12)

5. CUB's Position

CUB commends the IPA on what it believes are well-developed sections of the Plan regarding the procurement of energy efficiency, and agrees with many of the policy recommendations within it. CUB says Section 16-111.5B(3) of the PUA requires the utilities to provide the IPA with an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan. (CUB Response at 4-5)

After this assessment is given to the IPA, CUB says the IPA must include cost-effective energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal in the Plan. CUB notes the Commission then must also approve the energy efficiency programs and measures included in the Plan if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of the PUA. (CUB Response at 5)

CUB notes this is the second year the IPA is procuring incremental energy efficiency pursuant to Section 16-111.5B. In last year's Plan, CUB says AIC programs were forecasted to provide savings of 70, 834 MWh, reduce the energy required for the IPA procured portfolio by 25,409 MWh, and lower peak demand by 4 MW. In this year's Plan, CUB indicates AIC is proposing programs with estimated savings of 65,680 MWh, peak demand reductions of 2 MW, and savings attributable to eligible retail customers of 17,950 MWh. CUB says this is a reduction in savings of 5,154 MWh and 2 MW of peak demand from last year. CUB is disappointed that AIC was unable to bid a greater number of MWh into the incremental IPA energy efficiency, particularly in a year when AIC is also filing its three year Section 8-103 portfolio. (CUB Response at 5)

In last year's Plan, CUB notes ComEd programs were forecasted to provide savings of 173,753 MWh, reduce the energy required for the IPA procured portfolio by 22,574 MWh for the 2013 delivery year to 39,688 MWh for the 2014 delivery year, and reduce peak demand by up to 6 MW. This year, CUB says ComEd is proposing programs with savings of 432,848 MWh in the first program year, 550,143 MWh in the second program year, and 611,958 MWh in the third program year. CUB says these programs will deliver 16 MW of reduction in peak procurement for the 2014-2015 program year, and the savings attributable to eligible retail customers is 88,839 MWh in the first program year, 137,288 MWh in second program year, and 184,078 MWh in the third program year. Although it is possible for ComEd to be achieving greater savings, CUB commends ComEd for more than doubling the number of MWh from last year in only the first year of programs, increasing the savings by nine fold from last year over the three year program life, and more than doubling the demand reductions. (CUB Response at 5-6)

According to CUB, as this will only be the second time the IPA has procured incremental energy efficiency, questions remained as to how the process should operate to serve the interest of ratepayers. CUB notes the Commission ordered the IPA and Staff to initiate a workshop process following the Final Order in Docket No. 12-0544, regarding the 2013 IPA Plan. CUB says stakeholders, including CUB, utilities, Staff, and the IPA reached consensus on many issues through that process, for example, that IPA programs are separate from the Section 8-103 portfolio programs, and as such, that the utilities will exercise minimal administrative control over non-utility administered programs. CUB states as the IPA correctly points out, questions remain about this process in the second year of energy efficiency procurement. CUB believes that two of the most important questions to discuss are how to ensure that all cost-effective energy efficiency is being procured, and what authority the utilities, the IPA, and the Commission have in reviewing and approving or rejecting program bids submitted pursuant to Section 16-111.5B. Overall, CUB supports the IPA's conclusions in the Plan, and provides its comments in response to areas where the IPA has requested stakeholder feedback, specifically, in Section 7.1.3.1, Feedback Mechanisms, and Section 7.1.3.4, Consideration of All Third-Party Bids. (CUB Response at 6-7)

CUB indicates it agrees with the AG that the Commission should instruct utilities to include proposals for expansions of the Section 8-103 programs, even if they have not yet received Commission approval of those plans for the upcoming three years. CUB does not agree with ComEd that the 2014 IPA Plan should not include discussion of a programmatic planning link between the potential studies and the programs submitted to the IPA. (CUB Response at 7)

According to CUB, the PUA specifies that the IPA and the Commission are obliged to review whether all cost-effective energy efficiency is being captured for inclusion in the Plan. Otherwise, CUB asserts there would be no use for the utilities to submit a potential study to the IPA for inclusion in the Plan and review by the Commission. CUB says the fundamental rule of statutory construction is to ascertain and give effect to the legislature's intent, expressed by the plain language of the statute. In construing a statute, CUB says all statutory language should be given effect. CUB also says all statutory language should be construed so as to produce a consistent, unified whole rather than inconsistent and contradictory parts. CUB states no part of the statute should be rendered superfluous and no statutory provision should be interpreted so as to render another provision meaningless. Finally, CUB says it is presumed that a legislature did not intend an absurd, inconvenient or unjust result. (CUB Response at 7-8)

CUB argues that contrary to ComEd's position, the IPA is not given a vague statutory goal to capture all cost savings identified in a potential study. CUB asserts it is the utilities who bear the burden of developing a potential study and conducting an RFP to find all cost-effective energy efficiency that can be then submitted to the IPA for inclusion in the Plan. CUB believes the IPA's role is simple and clear: to include all cost-effective energy efficiency included in the assessment the utilities provide to the IPA. CUB asserts the Commission's role is more nuanced – it must review the work of the utilities and IPA to see if in the Commission's opinion, whether the Plan captures all cost-effective energy efficiency identified by the utilities and the IPA and if in fact it is practical to include all of that efficiency in the Plan. CUB says the utilities' potential studies required by Section 16-111.5B(3)(A) of the PUA allow the Commission to make that determination. In CUB's view, to believe otherwise would be to render that Section of the PUA superfluous. (CUB Response at 8)

CUB agrees with the IPA that the current process does not necessarily capture all cost-effective energy efficiency and recommends that the Commission order the utilities to make changes related to the timing of the potential studies and the content of the RFPs the utilities release for third-party vendor efficiency programs. (CUB Response at 8-9)

CUB asserts there are currently two issues with the potential studies. The first is timing: CUB says both ComEd and AIC released the most recent potential studies in the summer of 2013, the same time they are submitting assessments of potential cost-effective energy efficiency programs to the IPA. CUB states these potential studies were completed prior to the utilities filing the Section 8-103 statutory EEPS three-year plans, but the potential studies were not completed prior to when third-party vendors had to submit responses to the RFPs for efficiency programs pursuant to Section 16-111.5B. CUB believes that it would be ideal for potential studies to be released in the fall of the year prior to the utilities filing the three-year portfolios. CUB claims they would then be available to utilities prior to utility filing of the Section 8-103 EEPS plans with the Commission and prior to third-party vendors submitting responses to utility RFPs in the spring of that same year for the Section 16-111.5(B) incremental purchase of energy efficiency by the IPA. CUB suggests this would allow both utilities and vendors an opportunity to review and consider the most recent data available on potential studies before designing and submitting program bids for both the Section 8-103 and Section 16-111.5(B) procurement. CUB recommends that the Commission order utilities to ensure that potential studies are completed in the fall of the year prior to utilities submitting three year Section 8-103 plans. (CUB Response at 9-10)

Additionally, CUB suggests SAG participants, including CUB, did not believe it was clear that AIC's most recent potential study reflected the present landscape for energy efficiency in Illinois. Specifically, CUB says the potential study did not account for the incremental Section 16-111.5B programs as a source of efficiency savings in addition to the utility portfolio programs. In order for the potential studies to aid in setting a benchmark on how much energy efficiency is possible, and be informative to efficiency providers as well as the Commission and stakeholders, CUB believes the Commission should require the utilities and stakeholders to establish basic requirements for how the potential studies should be structured in the SAG process. (CUB Response at 10)

According to CUB, an important step in the process of "fully capturing" all cost-effective and practicable energy efficiency through the IPA process is ensuring that RFPs are written to encourage third-party vendors to submit bids, or at the very least, not prevent third-party vendors from submitting bids due to prohibitory language. CUB says this year's RFPs, which were written and released prior to the IPA/Staff workshops ordered in the 2013 procurement docket, contain several provisions which CUB believes prevented more third-party vendors from submitting program bids. CUB says stakeholders (including CUB), the utilities, Staff, and the IPA reached consensus on many issues through the workshops and comments, including that the IPA programs are separate from the Section 8-103 portfolios, and as such that the utilities will exercise minimal administrative control over non-utility administered programs. CUB states future RFPs may reflect that clarity and consensus, including, importantly, that third-party programs will not be administered as though they are part of a utility Section 8-103 portfolio. According to CUB, as the RFPs released this year did not reflect this now consensus position, and as the utilities continue to argue that they should have the authority to reject cost-effective third-party bids, CUB believes it is necessary to memorialize what language utilities should not include in RFPs, as some of the language this year may have prevented efficiency providers from submitting program bids. (CUB Response at 10-11)

CUB says ComEd's RFP stated that third-party vendor programs may be taken over by ComEd if ComEd believes it would "enhance" the program. CUB claims such a move would strip vendors of administrative and financial autonomy they may require to run a program, and likely prevented potential vendors from submitting bids. CUB says AIC's RFP stated that the utility will administer the programs on behalf of vendors. In CUB's view, this language suggests that AIC would effectively administer all third-party vendor programs as though they were part of the Section 8-103 portfolio. CUB says AIC's RFP also states that AIC has a right to modify the scale of a program. If vendors believe the utility may intervene to run the program, CUB believes it creates great uncertainty, which will likely prevent efficiency providers from submitting bids. (CUB Response at 11)

Another aspect of this year's RFPs which CUB believes may have inhibited the number of bids received, is the contract length specified. CUB notes while ComEd accepted bids for programs lasting 1-3 years, AIC only accepted bids for programs lasting 1 year. CUB asserts while three years is a significant improvement, both are too short a timeframe for many efficiency vendors to find bidding attractive considering vendors do not have a guarantee that the contract will be extended. In future years, CUB believes ComEd and AIC should be required to accept bids from vendors for an open-ended number of years. CUB believes the Commission should direct ComEd and AIC to include in the RFPs that third-party vendors will retain autonomy in administering programs under the IPA process, and prohibit the utilities from capping the number of years for which they will accept efficiency program bids. (CUB Response at 11-12)

CUB says a final issue that relates to the IPA's request for recommendations to allow for more flexibility in the third-party bidding procedure is the lack of coordination between utilities and vendors once proposals are received. According to CUB, if there are problems with a vendor's bid, such as a program not being found cost-effective when initially submitted to the utilities, bidders are currently not given an opportunity to revise the proposal and resubmit it for consideration. CUB says there is currently no opportunity for vendors to amend or improve programs after ComEd has found them to be not cost-effective. CUB believes there should be an opportunity for vendors to work with utilities on submitting cost-effective bids. CUB says the goal of the IPA energy efficiency procurement process is to maximize energy efficiency for the benefit of ratepayers and IPA customers. CUB believes the current process is unnecessarily inflexible and limits the number of bids which are actually successful. CUB recommends that the IPA request that the Commission order the utilities to work with stakeholders, Staff, and vendors to put in place a process that will maximize the number of viable program bids without exposing ratepayers to risk from vendors seeking to overestimate costs. (CUB Response at 12)

In CUB's view, to solicit feedback on how to further improve the RFP process, third-party vendors who bid programs for the 2013 and 2014 Plans should be invited to participate in a workshop process to discuss existing roadblocks and potential improvements to the bidding process. Going forward, CUB believes as part of the bid solicitation process, ComEd and AIC should highlight findings from the most recent potential studies, specifying what programmatic opportunities exist, as well as provide detail about existing programs in the RFPs for energy efficiency programs. (CUB Response at 12)

CUB agrees with the AG that the General Assembly has made clear its charge to the Commission to ensure that the IPA procurement plan, to the extent practicable, fully captures the potential for all cost-effective energy efficiency programs. CUB says it is essential for the Commission and the IPA to receive feedback from parties, including members of the SAG and third-party vendors who have submitted program bids, in order to learn how the process might be improved to maximize and capture the potential for all cost-effective energy efficiency programs. In line with meeting this goal, CUB supports the IPA's conclusion that an explicit ruling from the Commission about improvement to the RFP process would aid all parties. CUB maintains the Commission should order the utilities to develop RFPs that reflect the consensus achieved through the Staff and IPA workshop process, and the conclusions the Commission will reach in the Final Order in this docket. (CUB Reply at 1-2)

CUB claims an important part of capturing all cost-effective energy efficiency is allowing vendors to submit bids for programs longer than one year. CUB says AIC critiques the AG's suggestion that AIC only submitting one year of programs and savings for this Plan filing is inconsistent with the PUA's stated goal of capturing all achievable energy efficiency. According to CUB, AIC states nothing in Section 16-111.5B indicates that the utility should or must submit more than one year of savings and costs. CUB says the PUA also does not indicate that the utilities should only file one year of programs. CUB notes this year, ComEd submitted programs for three years. CUB agrees with the AG and the IPA that per the statute, the goal of this process is to capture all achievable cost-effective energy efficiency. CUB argues only accepting programs for one year vastly limits the number of eligible programs. CUB says the Commission should order ComEd and AIC to accept bids for an uncapped number of three years to maximize the number of cost-effective programs that will then be eligible to submit bids. (CUB Reply at 2)

CUB says the IPA raises two issues related to competition between utility programs and third-party vendor programs. The first is what it means for a third-party bidder's proposed program to be "competing" with or be "duplicative" of a utility program. CUB says there is no Commission-approved standard for these terms. The IPA proposes that the term "duplicative" should "mean a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers." The IPA proposes that the term "competing" would refer to programs where benefits could result from having offerings from multiple channels. CUB agrees with these definitions. (CUB Response at 13)

The second issue the IPA raises is the authority of the Commission to reject a third-party bidder's program that is "competing" with or "duplicative" of a utility's program but which otherwise passes the standard for cost-effectiveness. CUB agrees with the IPA's recommendation that the utilities should include all bids received in the assessment, even if the utility believes the bid to be duplicative or competing, using the IPA's definitions. CUB says the IPA would also include all programs in the Plan, with its own recommendations included, and the Commission would provide the final determination as to which programs are included based on any objections received that would change the Commission's understanding of if the program in question is or is not duplicative or competing. (CUB Response at 13)

CUB also agrees with the AG that the Commission should have the final word on assessing whether a cost-effective program is indeed competing, duplicative, and therefore, disruptive to existing Section 8-103 efficiency markets, and that it is important that individual utilities not assume the role of judge and jury when it comes to assessing whether a program is likely to disrupt the existing Section 8-103 efficiency market. CUB believes the AG is correct that utilities should not have the authority to screen out programs they determine to be a threat to the Section 8-103 programs. According to CUB, that is not to say that utilities should not provide input on whether a program is competing or duplicative; in fact, utility input is valuable, and CUB hopes utilities will continue to provide this information in the assessment. CUB agrees with the AG that the utilities should not be screening out programs because that authority lies with the Commission. (CUB Response at 13-14, Reply at 2-3)

CUB indicates both AIC and ComEd argue that the utilities should have the authority to screen out programs they believe are competing with or duplicative of utility programs. AIC states that neither competing nor duplicative programs should be approved, and that the utilities should have the authority to "take into account the factors identified by the IPA" if the Commission approves the IPA's standard. ComEd agrees with the standard proposed by the IPA, but recommends including two additional factors: "6) the effect(s) on utility joint program coordination, and 7) impact on Section 8-103 EEPS portfolio performance." CUB does not object to the inclusion of these additional criteria. CUB does disagree with ComEd's assertion that it has the authority to exclude third-party proposals from the assessment. CUB agrees with the IPA and the AG that that authority lies with the Commission. (CUB Response at 14)

According to CUB, the PUA does not grant utilities the authority to reject bids for programs similar to existing ones, or exclude such bids from even being considered. CUB believes the Commission should bar utilities from inserting language in the RFP, unless a standard Consideration of All Third-Party Bids, is adopted. If the Commission does adopt a standard for duplicative or competing programs, CUB supports the IPA's recommendation that the standard be a "multi-factor inquiry rather than a "bright line" test." (CUB Response at 14-15)

CUB says if a standard were established in this docket, it would provide certainty to third-party vendors as to what types of programs will likely be approved via this process. CUB claims it would also allow for utilities, the IPA, and stakeholders and other intervenors to provide feedback on these specific criteria prior to the Commission making a determination as to whether a vendor program which is similar to an existing utility program should be included. If the Commission does not wish to adopt the IPA's proposed standard at this time, CUB recommends that the Commission order the IPA, utilities, Staff, stakeholders, and third-party vendors to participate in a workshop process, possibly through the SAG, to discuss the implications of the IPA procuring programs that are similar to existing utility programs. (CUB Response at 15-16)

According to CUB, it is unclear why AIC is only willing to provide feedback and transparency related to possible programs if the utility is given the authority to reject programs. CUB says the Commission should reject AIC's proposal, as it would allow the utilities to reject program proposals without IPA, Commission, or stakeholder review, and would provide the utilities discretion that CUB believes rests with the Commission. CUB claims the General Assembly laid out a clear process for approval of an IPA Plan: a public process and a docketed proceeding before the Commission. CUB says the IPA Plan is scrutinized by any party that intervenes in the docket, and ultimately only approved by the Commission after it has made any revisions deemed necessary. CUB states to allow the utilities to make decisions about which programs are procured would be in opposition to the entire process. (CUB Reply at 2-3)

CUB says AIC further states that in the event a competing program is approved, however, the competitive program's savings should be reduced by the amount of the other competitive program's savings. CUB asserts AIC provides no support for this recommendation, much less any policy rationale for doing so. CUB asserts the result of AIC's proposal would likely be to reduce savings to third-party programs to such an extent that the program proposals were no longer viable. CUB believes the Commission should reject this recommendation from AIC. (CUB Reply at 3)

In its response, the IPA sought feedback related to whether AIC's SBDI program should be expanded or maintained at current levels. CUB appreciates AIC's and the IPA’s thoughtful examination of this issue. CUB recommends that AIC request that the Commission allow AIC to ramp up the program based on its performance going forward. (CUB Reply at 4)

6. DCEO's Position

According to DCEO, the IPA's decision to exclude DCEO from its 2014 Procurement Plan is inconsistent with the intent of Sections 8-103 and 8-104 of the PUA. DCEO says Sections 8-103 and 8-104 of the PUA require the utilities and DCEO to work concurrently to administer cost-effective energy efficiency programs to all utility customers. DCEO says the PUA specifically requires DCEO to administer energy efficiency programs that serve two of the most financially challenged utility customer classes, low income residents and the public sector. DCEO claims low income residents spend a greater percentage of their monthly income on energy and are the least able, in comparison to the other utility customers, to invest in energy efficiency measures that will reduce their energy bills. DCEO asserts the potential for energy efficiency in low income housing, particularly multi-family rental housing is very large. DCEO's contends its current low income energy efficiency programs cannot keep up with the demand in this sector, which is the impetus for DCEO to expand its Energy Savers Program as part of the 2014 IPA Procurement Plan in order to yield 3,769 MWh in energy savings. Similarly, DCEO seeks to expand its public sector Street Lighting Program through IPA's Procurement Plan, which it claims would yield 29,744 MWh in energy savings. In DCEO's view, the IPA's exclusion of these programs from its Procurement Plan is inconsistent with the PUA and prohibits DCEO from performing its statutory duty to serve low income residents and the public sector in conjunction with the utilities programs. (DCEO Objections at 1-2, Response at 2)

The IPA and DCEO acknowledge that amendments to the IPA Act are silent on how the Procurement Plan applies to DCEO. DCEO argues this omission was not the intent of the General Assembly when passing Senate Bills 1652 and 3811. In the absence of express IPA authority, DCEO believes the Commission has the authority to bring consistency to the energy efficiency programs under the PUA. DCEO claims the Commission has set a precedent by interpreting certain utility directives in the energy efficiency portfolio statute to also apply to DCEO. DCEO says the Commission has interpreted that provisions of the PUA that require the utilities to demonstrate that their programs are cost-effective applies to DCEO as well. DCEO also claims the Commission has determined that provisions of the PUA that require the utilities to provide an independent evaluation of their programs also apply to DCEO, even though the statute does not expressly mention DCEO. (DCEO Objections at 2, Response at 2-3, citing Docket No. 10-0562, Order at 63)

DCEO says there was consensus in the Commission-directed workshop process that cost-effective DCEO programs should be included in the procurement of energy efficiency for the IPA's annual portfolio. DCEO also says the AG also believes it is important to incorporate DCEO programs with the IPA 2014 Procurement Plan. DCEO requests the Commission interpret the amendments to the IPA Act to include DCEO's low income and public sector programs as part of the 2014 Procurement Plan consistent with the utilities programs. (DCEO Objections at 2-3, Response at 3)

DCEO claims all parties agree that DCEO's role in Sections 8-103 and 8-104 are inconsistent with Section 16-111.5B of the PUA. According to DCEO, the intent of the PUA is to ensure that all Illinois utility ratepayers receive the benefit of reduced energy demand through energy efficiency programs generally as well as the direct benefit of rebates and grants that lower specific ratepayers' energy costs. (DCEO Response at 1)

DCEO contends that similar to the electric utilities, it has a unique role in achieving the energy efficiency savings goals and objectives contained in the PUA. DCEO says the PUA requires it to administer energy efficiency programs that serve two of the most financially challenged utility customer classes, low income residents and the public sector. DCEO asserts low income residents spend a greater percentage of their monthly income on energy and are the least able, in comparison to the other utility customers, to invest in energy efficiency measures that will reduce their energy bills. DCEO claims public sector utility customers face similar financial constraints, in terms of the availability of funds to pay for energy efficiency projects and are confronted with an additional barrier related to public street lights – utility ownership of street lights and franchise agreements. DCEO says neither of the electric utilities' energy efficiency plans submitted to the IPA addresses the needs of low income and public sector ratepayers. (DCEO Response at 1-2)

DCEO argues that the Commission cannot approve the IPA 2014 Procurement Plan without the incorporation of DCEO's cost-effective Potential Study, which is included in the IPA's Procurement Plan as Appendix H. DCEO believes the Commission has the authority to bring consistency to the energy efficiency programs under the PUA. DCEO claims the Commission enjoys wide discretion to determine what the public interest requires and what measures are necessary for the protection of those interests. (DCEO Response at 2-3, citing City of Chicago v. Illinois Commerce Commission, 79 Ill.2d 213, 219–220 (1980))

In its Reply Brief on Exceptions, DCEO indicates it is gravely concerned that another workshop would do very little to do away with the uncertainty of a final answer regarding DCEO's role in the IPA annual procurement plan since the matter was already addressed in a prior workshop having yielded a consensus amongst stakeholders that DCEO should participate in the IPA process but, fell well short of a prescribed role for DCEO. (DCEO RBOE at 2)

7. NRDC's Position

According to NRDC, the absence of DCEO programs in the Plans both last year and this year is troubling and problematic. NRDC claims low income housing is one of the least developed and most significant opportunity sectors for efficiency, more than half of which nationwide were built before building codes began to require energy efficient windows, insulation and appliances. NRDC asserts partially as a result of this energy inefficiency, low income renters pay a much higher share - as much as 33% or more - of their income for electricity and gas, which means fewer resources for critical expenses such as food, transportation and health care. NRDC also claims owners of low income rental properties face higher costs, reducing their ability, among other things, to make other improvements to the properties. (NRDC Reply at 2)

NRDC contends residents of low income multi-family buildings have not enjoyed their share of energy efficiency investments, which are so much more valuable to them given the outsized share of their income that is swallowed by energy costs. NRDC says to exacerbate this problem by excluding low income programs from this procurement plan when the customers served by DCEO's energy efficiency portfolio fit squarely into the pool of customers who are served by the IPA, would be inequitable, counterproductive, and is unnecessary when there are multiple solutions at the Commission's disposal to ensure that low income customers can be served under the provisions of Section 16-111.5B. NRDC agrees with DCEO that the potential for energy efficiency in low income housing, particularly multi-family rental housing is very large. DCEO's current low income energy efficiency programs cannot keep up with the demand in this sector. (NRDC Reply at 2-3)

To address this issue, NRDC says the IPA provides three paths: (1) for the Commission to determine that, for the purposes of this Section alone, DCEO can be considered a "utility" and therefore can propose new programs or program expansions directly to the IPA in future years; (2) for DCEO to participate in the utility RFP process under Section 16-111.5B(a)(3); or (3) to make a legislative change to the Statute to more clearly define DCEO's role. (NRDC Reply at 3)

NRDC supports the first option outlined in IPA's Response as the most expedient solution to this problem. It would allow DCEO to directly file its programs with the IPA rather than go through the RFP process. NRDC agrees with DCEO that the Commission has the authority and discretion to provide consistency to the energy efficiency programs under the PUA and urges the Commission to exercise that ability at this time. NRDC is cognizant that there may be legal and administrative barriers that prevent DCEO, a state agency, from going through a private utility's RFP process. NRDC says the IPA has committed to providing the same analysis to timely filed DCEO-provided programs as the utility programs, and therefore the path is clear for the Commission to use its discretion and allow DCEO to file programs directly with the IPA. NRDC believes that it is urgent to provide expanded DCEO programs and should be a priority of the Commission. NRDC claims the stakeholders, through the IPA workshop process, all agree that DCEO programs should be included in the Section 16-111.5(B) process. DCEO has consistently expressed legal concerns that it cannot submit programs through the utility RFP process, and the IPA is willing to examine the DCEO programs directly going forward. NRDC sees a clear path forward on this issue once the Commission directs the IPA to allow DCEO to file its programs with the IPA. (NRDC Reply at 3-4)

Should the Commission conclude that it cannot direct IPA to allow DCEO to file its programs with the IPA despite the willingness of IPA to make that pathway available, NRDC encourages the Commission to act quickly to establish a process to determine the precise nature of the barrier that prevents DCEO from participating in the utility RFP process, and to craft solutions to eliminate this barrier along with the stakeholders who have expressed interest in this issue. (NRDC Reply at 4)

NRDC supports the inclusion of the IPA's Feedback Mechanism discussion in its Plan and disagrees with AIC and ComEd that this section should be removed. NRDC says ComEd, and by extension AIC through its support, is incorrect that nowhere within Section 16-111.5(B) is it stated that it is the goals of that section to fully capture the potential for all achievable cost-effective savings and no role is given to the IPA to pursue some unstated statutory goal to capture all cost savings identified in the potential study. NRDC argues that Section 16-111.5(B)(a)(5) explicitly states the objective of capturing all of the cost-effective potential for energy savings in the markets served by the IPA. (NRDC Reply at 4)

NRDC agrees with the IPA that fully capturing the potential for all achievable cost-effective savings is an iterative process. NRDC believes the IPA is correct that there is a broad swath of efficiency opportunities not yet being captured based on the potential study, which serves as a guide of what energy savings is available. NRDC agrees with CUB the statute explicitly requires submission of the potential study to IPA, which would make no sense and render that section of the statute superfluous if the IPA and Commission are not obliged to review whether all cost-effective energy efficiency is being captured for inclusion in the Plan. NRDC says that the statute does not spell out a specific planning link between the potential studies and the programs submitted to the IPA and ultimately approved, does not render the objective itself irrelevant to the IPA's review of the assessments, nor does it preclude the IPA from creating that link. (NRDC Reply at 5)

NRDC acknowledges that in this year, and every three years thereafter, there is a "chicken and the egg" problem, with Section 16-111.5B programs being approved before Section 8-103 programs are approved. NRDC says with no approved Section 8-103 programs for next year, it is not possible to definitively determine whether a program proposed for IPA procurement would complete with a Section 8-103 program. The IPA has proposed a solution – that the Commission conditionally approve programs, contingent on the outcome of the case in which the Section 8-103 programs are proposed. NRDC agrees with this approach to conditionally approve IPA programs during these transition years. (NRDC Reply at 5)

The IPA has put forth a set of factors by which the Commission can evaluate whether a program proposed by a third-party through the utility RFP is actually "duplicative" or "competitive." NRDC believes doing so would serve to provide clarity for future bidders and to provide a standard by which the Commission can resolve disagreements between parties about whether a utility's decision to exclude a program was warranted. Factors that IPA suggests the Commission consider include: (1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record); (6) the effect(s) on utility joint program coordination (for defining "competitive"); (7) impact on Section 8-103 EEPS portfolio performance (for defining "competitive"). NRDC is comfortable with the use of this set of factors when considering whether a program is duplicative or competitive. (NRDC Reply at 6)

As for the question of what point in the process competing or duplicative programs should be removed from consideration, NRDC agrees with the process outlined by the IPA. NRDC believes that it is completely appropriate for the utilities to pass first judgment on the question of duplication/competition as they are most familiar with the programs. NRDC says that is not the end of the story because the utilities still need to show all program proposals to the IPA, which can draw a different conclusion in the plan it sends to the Commission. NRDC says the Commission can also draw a different conclusion than either the utilities or the IPA, informed by input from other parties. NRDC believes the current process being followed is appropriate. (NRDC Reply at 6-7)

8. Staff's Position

Staff's understanding of the IPA's, ComEd's and AIC's overall position on the issue of whether DCEO can participate in the 2014 procurement process is that DCEO is not a utility and therefore, Section 16-111.5B, in particular Section 16-111.5B(a)(5) does not apply to DCEO. Staff's understanding of DCEO's proposal is that DCEO, not the utilities, ComEd and AIC, would be procuring the DCEO's proposed energy efficiency programs. Therefore, according to the IPA, ComEd and AIC, since Section 16-111.5B(a)(5) only provides for utility procurements, DCEO's proposal, regardless of merit is not authorized under the PUA and therefore it cannot be approved by the Commission as part of the IPA Plan. (Staff Reply at 12-13)

Staff says DCEO argues that neither ComEd's nor AIC's energy efficiency plans submitted to the IPA address the needs of low income and public sector ratepayers. According to DCEO, these ratepayers have limited funds to pay for energy efficiency measures and programs. DCEO argues that the Commission cannot approve the IPA's plan without the plan including DCEO's proposed energy efficiency programs proposal, Appendix H to the IPA's Plan. The main support by DCEO for this argument, is its reliance upon Section 16-111.5B, in particular Section 16-111.5B(5). (Staff Reply at 13)

Staff notes the AG supports the inclusion of DCEO's programs in the plan given that DCEO oversees the delivery of Section 8-103 programs that are targeted to low income customers. The AG argues that the low income programs are ripe for expansion and represent significant cost-effective opportunities to increase energy efficiency and provide benefits to low income customers. The AG requests that the Commission take evidence or comments on the bidding difficulties that have prevented DCEO's participation in past plans to date. The AG is hopeful that an amendment to the IPA's Plan can be crafted so that the Commission can approve cost-effective DCEO programs as part of the IPA Plan. (Staff Reply at 13-14)

Staff states while potential legal impediments in Section 16-111.5B(a)(5) may limit DCEO from implementing its programs because DCEO is not a utility, there are benefits associated with the cost-effective programs as outlined in Appendix H of the IPA Plan. Staff suggests one possible option for considering these programs within this docket may be for the Commission to make a finding about inclusion of the Appendix H programs within this docket, but then initiate a follow up proceeding to the pending docket which would seek to alter the DCEO proposal from the DCEO "procuring" programs to the utilities doing the procuring in partnership with DCEO, consistent with Section 16-111.5B(a)(5). (Staff Reply at 14)

Staff believes the Commission should go beyond what CUB recommends regarding energy efficiency and require that at a minimum the potential studies include analyses of "economically efficient potential." Staff says the potential studies presented by the utilities measure "technical potential" and "economic potential." As used in the potential studies, Staff says technical potential is the level of energy savings that could be realized if all energy-using equipment was replaced with the most energy efficient technology available, while economic potential is the amount of savings possible from using the most technologically efficient replacement equipment that has positive net benefits compared to a base level of equipment. (Staff Reply at 14-15)

Staff's concern is that this definition of economic potential is equivalent to asking "What is the potential energy savings from replacing current equipment with the most energy efficient piece of equipment that provides net benefits to customers?" Staff claims it does not answer the question, "What is the potential energy savings if current equipment is replaced with the energy efficient equipment that maximizes net benefits to ratepayers?" Staff asserts the second question addresses the issue of which equipment efficiency would maximize the welfare of ratepayers by providing the economically efficient level of energy efficiency. According to Staff, the answer to this question is what economists typically consider to be economic efficiency. Since benefits are tied to energy savings, Staff contends economic efficiency also provides for the greatest overall energy savings for a given budget. (Staff Reply at 15-16)

Staff argues economically efficient potential is determined through marginal analysis. Staff says marginal analysis requires ranking equipment in degree of energy efficiency relative to the current stock of equipment from the lowest to the highest. Once the ranking is complete, Staff says the analysis examines the additional benefits and additional costs of moving from the current equipment to the piece of equipment that is ranked slightly higher. According to Staff, this examination would be completed again comparing the additional costs and benefits from the next highest-ranked piece of equipment to the previously examined more efficient equipment. Staff says this process is repeated until the additional benefits of the next highest-ranked piece of equipment are less than the additional costs of that piece of equipment. Staff claims economic efficiency is determined by choosing the last piece of equipment that achieves additional benefits greater than additional costs. (Staff Reply at 16) In its Reply, Staff provides an example to illustrate its point. (Staff Reply at 16-18)

According to Staff, economically efficient potential informs the Commission, the utilities and interested stakeholders what levels of energy efficiency maximize consumer net benefits. In addition to the impact it has on informing the IPA in the procurement of energy efficiency, Staff says economically efficient potential has value when budgets are limited as is the case for energy efficiency programs under Section 8-103. By considering the marginal benefits and marginal costs, Staff contends the economically efficient level of an energy efficient measure provides the highest levels of savings for a given budget. Due to the advantages of analyzing economically efficient potential, Staff recommends that the Commission order the utilities to provide an analysis of economically efficient potential in future potential studies. (Staff Reply at 18)

9. Commission's Conclusions

In this proceeding, there are several issues related to the energy efficiency provisions of Section 16-111.5B of the PUA, some of which appear to be at least partly interrelated. First, the Commission will address the role of DCEO in Section 16-115.5B energy efficiency programs.

The IPA Plan notes that DCEO did not participate in the utility-run RFP process, but rather submitted its proposed cost-effective efficiency programs to the IPA directly. The IPA states that it determined that it could not include the programs proposed by DCEO pursuant to Section 16-111.5B at this time because DCEO is not a utility as the term is used in Sections 16-111.5 and 16-111.5B of the PUA. To the extent that the Commission holds that DCEO is a “utility” pursuant to Section 16-111.5B, the IPA says it will, going forward, provide the same analysis to timely filed DCEO-provided energy efficiency programs. The IPA indicates a second option is for DCEO to participate in utility RFP processes required by Section 16-111.5B(a)(3). According to the IPA, the third option is to build consensus toward a legislative change that more clearly defines DCEO’s proper role. It appears the IPA is looking for guidance from the Commission.

DCEO has intervened in this proceeding and requests the Commission interpret the amendments to the IPA Act to include DCEO's low income and public sector programs as part of the 2014 Procurement Plan consistent with the utilities programs.

The AG requests that the Commission take evidence or comments on the bidding difficulties that have prevented DCEO’s participation in IPA Plans to date. Once a clearer understanding of these contracting difficulties is presented, it is the AG’s hope that the IPA, DCEO and the utilities can craft an amendment to the Plan that permits Commission approval of cost-effective DCEO programs in the 2014 IPA Plan, as well as in future annual procurements.

According to AIC, it does not appear to be appropriate to include DCEO programs in the IPA Plan at this juncture. AIC states while it remains committed to working with DCEO so it can participate next year in a way that complies with the law, the AG's recommendation that DCEO participate in this year's Plan should not be followed.

ComEd agrees that clarification regarding the role of the DCEO in incremental energy efficiency programs is warranted. ComEd argues that no language in the law governing this proceeding, Section 16-111.5 of the PUA, nor any other provision of Illinois law, indicates or suggests that DCEO should be treated differently than any other third-party vendor in the procurement process. ComEd believes the Commission should conclude that, going forward, if DCEO wishes to participate in the Section 16-111.5 procurement process, it must do so through the third-party RFP process set forth in the PUA.

The Commission has reviewed the positions of the parties as well as the applicable statutory provisions. It is clear that the Commission cannot treat DCEO as a utility under Section 16-111.5 or 16-115.5B of the PUA. In the Commission's view, there is no reasonable reading of the statute that would allow it to do so, and AIC, ComEd, the IPA, and the AG seem to acknowledge as much.

The Commission understands the views of DCEO and those who wish for DCEO to participate in procurement proceedings and to implement energy efficiency programs under Sections 16-111.5 and 16-111.5B of the PUA. The Commission is committed to implementing energy efficiency programs to the fullest extent possibleand is of the opinion that all Illinois ratepayers should receive the benefit of reduced energy demand through energy efficiency programs. The Commission's authority is constrained by the statutes under which it operates. With regard to procurement proceedings under Sections 16-111.5 and 16-111.5B, the Commission acknowledges its authority over DCEO is limited. The Commission notes DCEO is a separate State Agency and, as such, the Commission's jurisdiction over DCEO is also limited. However, the Commission shares in both DCEO and the AG's position that it should endeavor to increase the delivery of overall achievable energy efficiency while also providing needed benefits to low income electric utility customers who often struggle to pay their bills. Thus, the Commission directs that a workshop should be held to address the barriers to DCEO's participation through the third-party RFP process. It is not apparent to the Commission what those undefined barriers are, only that the parties have agreed that they exist; thus, it is difficult for the Commission to determine what, if any, course of action can be taken to remedy the situation within the scope of this proceeding. Although the Commission cannot mandate that DCEO take part in this workshop, in the interest of including energy efficiency programs to address the needs of low income customers in the IPA's future procurement plans, it would encourage DCEO's participation. The Commission urges the parties to hold any workshops in the timeliest manner practicable and to report to the Commission in the next available IPA procurement proceeding on the results of the workshop. Alternatively, the Commission welcomes DCEO's participation in a formal docketed proceeding or in informal discussions about these barriers, if DCEO considers that to be a more fitting way to address the issue.

The Commission understands that DCEO does not routinely participate in docketed Commission proceedings. In the future when DCEO does choose to participate, the Commission expects DCEO to more diligently follow the Commission's Rules of Practice, 83 Ill. Admin. Code 200, with regard to the filing and service of pleadings. Additionally, in future proceedings, the Commission will not be tolerant of DCEO filing pleadings that are inconsistent with the established schedule, particularly in cases with relatively short deadlines.

In the first of the IPA's four policy issues, the IPA initially suggested that the Commission consider the implications of the lack of a feedback loop or mechanism for consideration for inclusion of energy efficiency programs in the procurement plan that would ensure the statutory goal of fully capturing the potential for all achievable cost-effective savings, to the extent practicable. This suggestion is endorsed by the AG and CUB. For slightly different reasons, ComEd and AIC object to the proposal and argue it is unnecessary and that section of the Plan should be deleted.

In response to the IPA's concern, the AG recommends the Commission instruct the utilities to include proposals for expansions of established and cost-effective Section 8-103 programs that the utilities expect to continue in their September 1 three-year filings they submit proposed programs to the IPA. CUB, in response to the IPA's concern, recommends that the Commission require utilities to submit potential studies earlier than presently required, stating they should be released in the fall of the year prior to the utilities filing the three-year portfolios. Although its position is not entirely clear to the Commission, it appears the IPA agrees with the AG, to at least some extent. (See IPA Response at 13) ComEd and AIC object to both recommendations.

The IPA initially suggested that the Commission might modify the utilities' RFP procedure for the third-party programs to be added into next year's Procurement Plan. The IPA's position then evolved in response to objections, responses and replies. Specifically, the IPA does not ultimately seek any direct Commission intervention other than request the utilities coordinate with stakeholders. The Commission agrees that the utilities should make every effort to coordinate with stakeholders on improving and clarifying the RFPs. As a result, the Commission declines to order the utilities to take any additional formal steps after the RFP to secure additional third-party programs.

The Commission finds unworkable the AG's recommendation that the utilities include proposals for expansions of Section 8-103 programs to be proposed in their September 1 three-year filings when they submit proposed programs to the IPA. The Commission does not understand how the AG expects utilities to know, with any degree of certainty, which programs the Commission will adopt for expansion before the Commission has entered an order pursuant to Section 8-103. In fact, the Commission itself cannot know that. While the statutory framework related to energy efficiency programs has arguably created an unfortunate situation, it is simply unfair to put the utilities in a situation where they must guess in one proceeding what the Commission will subsequently decide in another proceeding. The Commission suggests that an effective solution would be for the General Assembly to modify the existing framework to address the timing. The Commission, however, cannot simply ignore the existing framework. The AG's proposal is rejected.

AIC and ComEd express concerns with CUB's proposal to require potential studies to be advanced by approximately one year. Among other things, they argue it is inconsistent with the statute, would constitute an inefficient use of resources, and would result in reliance on outdated data. The Commission appreciates CUB's goal of allowing both utilities and vendors an opportunity to review and consider the most recent data available on potential before designing and submitting program bids for both the Section 8-103 and Section 16-111.5(B) procurement. If CUB's proposal were adopted, it is clear that it would result in utilities and vendors relying on older data than currently is relied upon. While the Commission does not entirely agree with ComEd's suggestion that CUB's proposal is impermissible pursuant to Section 16-111.5(a)(3) of the PUA, CUB's proposal does appear somewhat inconsistent with what is contemplated by that Section of the PUA. For these reasons, the Commission declines to adopt CUB's proposal in this proceeding.

CUB also takes issue with some of the language in the most recently issued RFPs and recommends the Commission order the utilities to work with stakeholders, Staff, and vendors to put in place a process that will maximize the number of viable program bids without exposing ratepayers to risk from vendors seeking to overestimate costs. CUB also recommends that the Commission require the utilities to issue RFPs for an open-ended time period. The Commission believes CUB has raised interesting concerns regarding the RFPs. The Commission is not convinced at this time, however, that an RFP with an open-ended time period is a good idea. However, the Commission notes that CUB and the IPA both recommend that the utilities work with stakeholders on improving the RFP process.

Given that specific proposals related to potential studies were raised in CUB's Response to Objections and that additional specific recommendations were raised in Staff's Reply to Responses, the Commission is concerned that the record on these issues is not as complete as it should be, particularly in a proceeding with an expedited schedule. As a result, the Commission believes it would be best if such matters were addressed in workshops before a Commission order on such issues is entered. Therefore, the Commission directs Staff to work with CUB, the AG, and any other interested parties to conduct workshops, as needed, to determine what improvements, if any, can be incorporated into the potential studies, the timing of any filings related thereto, as well as improvements to the RFP process.

The Commission will next turn to the IPA's fourth policy issue, namely the procedure for removing third-party bids with a TRC greater than one that would conflict with utility-run energy efficiency programs. The IPA noted that there is a consensus amongst the parties that although the utility must identify and present for Commission (and IPA) consideration of all third-party RFP bids, the utilities do not have the authority to exclude third-party bids with a TRC greater than one from Commission consideration simply because they would hamper a utility-run program. The IPA identified the concepts of “duplicative” and “competitive” to categorize the types of third-party programs that utilities have marked as undermining utility-run energy efficiency programs. The IPA identified two purposes for these definitions: (1) Allowing the Commission to decide to include or exclude third-party programs that hamper utility-run programs based on a known standard; and (2) Providing potential bidders with an ex ante signal about what programs are likely to be excluded. However, the IPA noted that these terms are not in the statute, and currently have no formal standard attached to them for the Commission to apply (or for potential bidders to rely on up front). To provide structure to these concepts, the IPA proposes to define “duplicative” as a program that overlaps with an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers. The IPA says the general goal would be that duplicative programs are to be avoided, but that "competing" programs would be acceptable to the extent that the competition does not render one or both non-cost effective. To that end, the IPA proposed a seven-factor test for “competing” to determine whether such a program should be excluded, five of which were initially proposed by the IPA and to which ComEd added two factors.

ComEd and AIC appear to have no disagreement with the IPA's definition of the term duplicative. With regard to competing programs, it appears the IPA, ComEd and AIC all agree that the IPA's proposed five factor test, plus the two additional factors identified by ComEd, should be used to determine if a program is competing. The IPA, ComEd, and AIC all believe the utility should be allowed to screen out duplicative and competing programs when the utilities submit their proposals to the IPA. It appears those three believe that information regarding such screened programs should be submitted to the IPA for review. The AG believes all RFPs that pass the total resource cost test should be submitted to the IPA for consideration for inclusion in the proposed procurement portfolio and the utilities should not screen out programs before submitting them to the IPA. The AG suggests in the IPA submittal, the utilities should explain fully why they believe a particular program is duplicative or competing, including a description of specific aspects of the program that are deemed problematic so that the IPA could determine in its Plan possible steps to eliminate problematic aspects of a particular program. The IPA and AG also believe that the Commission should have the final word on assessing whether a cost-effective program is indeed competitive, duplicative and, therefore, disruptive to existing Section 8-103 efficiency markets. CUB expresses concerns similar to those raised by the AG, while the utilities do not appear to object to the Commission’s ultimate authority on competitiveness and duplicativeness.

In the event a competing program is approved, AIC asserts the competitive program's savings should be reduced by the amount of the other competitive program's savings and it must be realized that the utility-provided TRC analysis may no longer be accurate (because the TRC test, which contains multiple factors, assumes the program is implemented in isolation). AIC believes utilities should be permitted to recalculate the TRC value for each competing/duplicative program to account for the fact that a program would no longer be implemented in isolation.

It appears to the Commission that the existing practices with respect to duplicative and competing programs are working effectively. The Commission believes the description in the IPA's Reply of how duplicative and competing programs should be handled is reasonable and directs the parties to present proposals in compliance with that procedure. (See IPA Reply at 10-11) The Commission notes that much of what the IPA, the utilities, the AG, and CUB recommended appear to memorialize current practice. However, the Commission agrees with the IPA that formal standards for "duplicative" and "competitive" would help both stakeholders and potential bidders, and thus adopts the IPA's recommended definitions.

The AG recommends, if the IPA does not intend to assume an oversight role for energy efficiency programs, then the IPA should request that the Commission enter an Order that makes clear that the utilities will assume responsibility for the evaluation and successful delivery of these programs, consistent with, to the extent practicable, the evaluation practices followed under Section 8-103 of the PUA. ComEd and AIC object to the AG's recommendation. The IPA agrees that oversight over utility activities regarding Section 16-111.5B-authorized programs is appropriate, but declines to insert itself into an inappropriate oversight role. The IPA also suggests this is an appropriate topic for discussion in workshops, rather than being decided in this proceeding. While it is not entirely clear what the AG proposes, the Commission agrees with the IPA's suggestion and directs interested parties to address this issue at the workshops discussed above.

The IPA and AIC were initially in disagreement over the level at which AIC's SBDI program should be approved. It appears the two parties now agree that the SBDI program should be approved at the "base level" of 30,179 MWh savings goal. The Commission finds this agreement to be reasonable and it is hereby approved.

ComEd and AIC both requested specific clarifying determinations by the Commission. These appear to not be opposed by any party and the Commission grants those determinations. To the extent there are other recommendations by parties not specifically addressed in this conclusion, the Commission declines to accept them at this time and suggests the parties discuss them at the workshops addressed earlier in this conclusion, except with respect to the consensus issues identified in Section 7.1.4.4 and Section 7.1.5.3 of the Plan, which were accepted by the IPA, were made part of the Plan, and are hereby expressly adopted by the Commission.

C. Alternative Compliance Payments

1. RESA's Position

In the 2014 Procurement Plan, the IPA notes the amount of Alternative Compliance Payments, which it received from RESs: approximately $7.1 million in 2010, approximately $5.6 million in 2011, and approximately $2.2 million in 2012. The IPA then notes that, in September 2013, it expects to receive approximately $40 million in ACPs for the June 2012 through May 2013 compliance period. The IPA attributes this increase in ACPs to being a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities. (RESA Objections at 7-8)

According to RESA, the IPA's explanation is only partially accurate. RESA claims another cause was the increase in the ACP rate as a result of a changed assumption. RESA says the May 17, 2012 estimated ACPs for the June 2012 through May 2013 compliance period, posted by the Commission pursuant to Section 16-115D(d)(1), of the PUA, were $0.6338/MWh for AIC and $0.9085/MWh for ComEd. RESA also says on May 13, 2013, the Commission published, also pursuant to Section 16-115D(d)(1) a notice that it had revised its estimated ACPs as follows: $0.6687/MWh for AIC and $0.9724/MWh for ComEd. The reason given for the revision was that the May 17, 2012 estimated ACPs assumed that ACP revenues collected by AIC and ComEd from their hourly customers would be used to purchase RECs required for eligible retail customers' renewable energy credits portfolios. RESA alleges this assumption was incorrect. RESA says the notice also indicated that actual ACP rates would be established by July 1, 2013. RESA says the actual ACP rates were identical to the May 13, 2013 estimated ACPs. (RESA Objections at 8)

RESA states while the change in ACP rates, on a per MWh basis, may not seem large, the change is very significant when considering the total volumes of electricity sold by RESs. RESA says the amount of that increase was greater than the entire previous year's actual ACP rate for each utility, $0.0584/MWh for AIC and $0.0568/MWh for ComEd. RESA also asserts the timing of the notice of the changed assumption and the revised estimates, one year after the publication of the earlier estimate and 11 ½ months into the 12-month compliance period, made it impossible for RESs to accurately reflect these increased ACP costs in the products they provide to their customers. RESA says for 11 ½ months, the best information RESs had with which to anticipate ACP charges required by law to comprise 50% of their compliance, was the estimated ACP published by the Commission in May 2012. According to RESA, the May 13, 2013 increase of this estimated number was a substantial change that made RESs' reliance on the previous estimate inadequate for them to reflect the actual ACP cost in their product pricing for customers during that 11 ½ month period. In RESA's view, competitive markets require predictability in order for suppliers to accurately forecast forward changes, but this change was unprecedented until 2013, so it was virtually unforecastable. (RESA Objections at 8-9)

RESA requests that, in the future, if assumptions in the manner in which ACPs are calculated are changed, those changed assumptions should be made prospectively. RESA says if a changed assumption were reflected in the subsequent, rather than the current, compliance period, RESs would have some opportunity to adjust prices accordingly. (RESA Objections at 9)

In its Brief on Exceptions, RESA suggests at a minimum, to encourage the IPA to notify the Commission Staff promptly when there is a changed assumption in the calculation of the ACP and the Commission Staff to publish the revised estimated ACPs, resulting from that changed assumption as soon as possible. (RESA BOE at 4) In its RBOE, RESA also supports Exelon's proposal that that the Maximum and Estimated ACP rates, including assumptions, be published on a forward basis for the full time period of the procurement plan or in the alternative all available components of the ACP calculation be published/updated on a monthly basis. (RESA RBOE at 3-4)

2. Exelon's Position

In Exelon's view, the Plan demonstrates some of the complexities associated with mandating long-term contracts, for any resource. In 2010, in accordance with a previous IPA Plan and following a competitive procurement, utilities executed 20-year contracts for bundled renewable energy and renewable energy credits. Since that time, there has been a dramatic shift in competition for residential and small commercial customers, resulting in significant load migration away from the utilities, and with the added migration due to the number of communities that have implemented municipal aggregation for electric load. (Exelon Objections at 8)

Given the amount of load migrating to ARES as a result of this robust competition, Exelon says the Plan again concludes that there is likely an insufficient number of bundled ComEd customers to support the commitments made to renewable energy resources through competitive procurements in previous years within the statutory price cap. Consequently, due to the costs exceeding the cost cap, ComEd's ability to accept the full amount of contracted renewable energy resources under the long-term contract lies in question. Exelon notes the Plan proposes to use the ACP payments that have been collected by ComEd from its hourly-priced service customers as necessary to supplement payment to the suppliers to the extent such payment would exceed the individual utility renewable resource budget caps in a given year. (Id.)

Without admitting or denying the IPA's legal authority to use the Renewable Energy Resource Fund as proposed in this year's Plan, Exelon does not oppose the proposal in recognition of the fact that the IPA has inherited a difficult situation in that commitments were made under long-term renewable procurements that are not necessarily sustainable by utility bundled customers within the statutory rate cap. According to Exelon, lack of opposition to use of those funds for this year's Plan should not be interpreted as agreement with this proposal as it relates to monies collected from ARES, nor shall it be construed as the appropriateness of such a proposal for future years. Exelon also says the statute's directive that ACP payments are to be used to "purchase renewable energy credits" may limit how those funds may be used and notwithstanding Exelon's position in this proceeding, it reserves the right to challenge the IPA's use of these funds in the future. (Exelon Objections at 9)

Exelon believes regardless of whether or not any renewable purchases are made, the Commission should modify the ACP posting process. Currently, ARES are notified of the ACP for only a single year, which does not provide ARES with enough information to properly include those costs in fixed price contracts which go beyond that single year. Exelon says recently, a change was made regarding assumptions that went into the ACP, the resulting recalculation of which had a "dramatic" effect on ARES costs to serve, and no time in which to appropriately manage their risks for that change. (Exelon Objections at 9)

In order to ensure that the process is transparent, and that ARES have all available information, Exelon suggests that the maximum and estimated ACP rate ($/MWh), including assumptions, be published on a forward basis for the full time period of the Plan. If that is not possible or practicable, Exelon asks that all available components of this calculation be published and updated on a monthly basis, to enable ARES to make their own assessments and appropriately take into account those factors within their respective portfolios. Exelon says such components would include:

- The total amount of dollars that the utility contracted to spend on all renewable resources (by resource type) by compliance period;
- Forecasted load of eligible retail customers, at the customers' meter, by compliance period; and
- The maximum allowable annual estimated average net increase due to the costs of the utility's purchase of renewable energy resources included in the amounts paid by eligible retail customers in connection with electric service, as described in item (2) of subsection (c) of Section 1-75 of the IPA Act for the compliance period, and as established in the approved procurement plan.

(Exelon Objections at 9-10)

3. The IPA's Position

The IPA notes RESA and Exelon raised concerns about changes between the estimated ACP rate provided to ARES and the final ACP rate actually assessed to ARES. The IPA says it is not involved in setting the ACP rate, and the process of determining the ACP is not part of the Procurement Plan. As a result, the IPA does not believe this issue is appropriate for litigation in this docket. (IPA Response at 8)

In its Reply Brief on Exceptions, the IPA says RESA appears to have a misread the PUA because the IPA does not have a role in setting the estimated ACP or the actual ACP. The IPA indicates Staff, without any input from the IPA, develops the estimated and actual ACPs, and is solely responsible for any changes in ACP methodology during a compliance year. (IPA RBOE at 6)

The IPA indicates it is sympathetic to RESA's travails with changes in the ACP estimation; however, the IPA believes even RESA's minimum recommendation is not consistent with Illinois law. The IPA strongly urges the Commission to reject RESA's recommendations and thus avoid writing the IPA into the process of determining the ACP when the IPA has no such role under Illinois law. (IPA RBOE at 7)

4. WOW's Position

WOW notes that Exelon and RESA both propose that the method for computing the alternative compliance payment rate be changed so that changes in factors used to calculate the ACP rate are applied prospectively and not in the current compliance period. (WOW Response at 3-4)

WOW asserts RESA's and Exelon's primary proposals are in conflict with the Section 16-115D(d)(1) of the PUA, however, Exelon's alternative proposal is not. WOW says the statute states the Commission is to post estimates of the alternative compliance rates during the compliance period, and has the discretion to post updates as often as once per month up to July 1, at which time the Commission is to post the Actual Alternative Compliance Payment Rate for the compliance period that ended as of May 31. (WOW Response at 4)

According to WOW, the ACP rate for a compliance period is to reflect what occurs in that period. WOW states as we enter the 2014-2015 period any changes to the factors that affect the alternative compliance payment rate between June 1, 2014 and May 31, 2015 would be captured in the Actual Alternative Compliance Payment Rate ("Actual Rate") that posts on or before July 1, 2015. WOW says that Actual Rate is currently used by ARES and utilities to calculate the alternative compliance payment they make in the same year -- on September 1, 2015. As WOW understands it, the RESA and Exelon proposal is asking that they not have to pay on that rate until one year later – September 1, 2016. WOW is concerned the potential unintended consequence of RESA's and Exelon's proposal is that we have an unknown ACP rate for the payment due on September 1, 2015 or perhaps the payment in 2015 is skipped. WOW argues neither of which is in conformance with the statute. (WOW Response at 4-5)

WOW says Section 16-115D(d)(2) of the PUA sets forth the requirement that the ACP is to be paid on September 1 following the end of the compliance period running from June 1 to May 31. In WOW's view, short of a legislative change to the language it appears that RESA's and Exelon's primary proposals are in conflict with the statute. It seems to WOW that Exelon's alternative proposal for monthly updates is within the scope of the discretion granted the Commission by Section 16-115(D)(d)(1) of the PUA. (WOW Response at 5)

WOW notes that Staff recommends that the Commission take no action in this docket in relation to RESA’s concerns over the procedures for computing and announcing ACP rate estimates because the incident relied upon by RESA for making this change was not significant when it occurred in 2009 and ACP rates have nothing to do with IPA procurement plans for utilities. The IPA has the same position as Staff because the IPA has no role in setting the ACP rates. (WOW Reply at 3)

WOW says the ACP rates are set by the Commission and not by the IPA; however, use of the ACP funds is discussed within the 2014 Plan so as to provide a complete overview of renewable energy resource procurement for utilities and through the RERF. In addition, WOW says the Commission has interpreted its statutes as not granting it authority to approve spending of funds in the RERF; however, WOW claims the Commission has exercised authority over how the utilities ACP money is spent and the IPA is asking for the Commission do so again in this case. (WOW Reply at 3-4)

WOW states the Commission has authority over the ACP rate, and precedent was set in the approval of the 2013-2014 Procurement Plan for the Commission to address ACP issues as it relates to the utilities use of their ACP funds. WOW contends the Commission could address the issue in this docket, or the matter could be put into another docket if the Commission prefers or if Staff thought that there was benefit to reviewing it in a separate docket. WOW believes that it is most expedient to address the issue in this docket. (WOW Reply at 4-5)

WOW asserts Staff’s response on this issue does not resolve the concerns WOW raised in its Response. WOW is concerned that RESA's and Exelon's proposal is contrary to Section 16-115D(d)(1) of the PUA and could potentially result in alternative compliance payments not being made during the transition period (of making ACP adjustment in prospective years) in the absence of a modification or clarification of the proposal. (WOW Reply at 5)

5. Staff's Position

RESA requests that, in the future, if assumptions in the manner in which ACP rates are calculated are changed, those changed assumptions should be made prospectively. Staff recognizes that ARES and ARES customers have a legitimate interest in knowing the value of ACP rates as soon as possible, ideally in advance of when ARES make electric price offers to potential customers. Staff notes Section 16-115D of the PUA seems to anticipate and accommodate this interest. (Staff Response at 8-9)

According to Staff, before actual ACP rates are established, Section 16-115D intends ARES to be given estimates; before estimates are given, the General Assembly intends ARES to be told the maximum levels that the ACP rates may reach. Staff says the Commission may not refuse to take into account changes that will lead the actual rate to vary from previous estimates. Staff suggests more apropos to RESA’s request, the Commission may not guarantee that assumptions made to generate estimates of

ACP rates will remain valid. Staff says to do so would completely ignore the fundamental difference between estimated and actual rates that the PUA built into the structure of Section 16-115D. (Staff Response at 9)

In support of its request, RESA complains that, in one instance since 2009 (when Section 16-115D became law), the estimates were not 100% accurate projections of the actual ACP rates. In Staff's view, RESA exaggerates the significance of that one inaccuracy when it implies that it was a major contributing factor to the increase in ACP revenues projected in the IPA Plan. Staff says had the first ACP rate estimates been correct, the resulting ACP revenues collected from ARES would have been 281% of the previous year's collections, while the corrected ACP rates have generated an actual increase of 288% over the previous year. Staff believes the reasons for the increase in revenues for the IPA's RERF have nothing to do with the initial inaccuracy in the ACP rate estimates. (Staff Response at 9-10)

In any event, Staff argues issues of this sort arguably have nothing to do with IPA plans. Staff says RESA is not arguing for a change to the Plan. Staff also says in a previous procurement plan docket, the Commission held ACP rate issues to be beyond the scope. Staff recommends that the Commission take no action in this docket in relation to RESA's concerns over the procedures for computing and announcing ACP rate estimates. (Staff Response at 10)

6. ICEA's Position

ICEA says RESA notes that RESs experienced a dramatic increase in the ACP for the June 2012 through May 2013 compliance period due, in part, to a change in assumptions on the part of Staff developing the ACP rates. ICEA claims dramatic and unanticipated changes can wreak havoc on suppliers' costs, and therefore on the offerings that they are able to make to customers. RESA's Objections request that, in the future, if assumptions in the manner in which ACPs are calculated are changed, those changed assumptions should be made prospectively. ICEA says for example, if a changed assumption were reflected in the subsequent, rather than the current, compliance period, RESs would have some opportunity to adjust prices accordingly. ICEA notes for similar reasons, Exelon recommends that the Commission modify the ACP posting process, publishing forward data. ICEA supports those suggestions. (ICEA Response at 6-7)

In response to concerns voiced by ICEA and RESA regarding the ACP, the IPA declined to address the matter. The IPA indicated that the agency is not involved in setting the ACP rate, and the process of determining the ACP is not part of the Procurement Plan. Consequently, both the IPA and Staff indicated that they do not believe the issue should be litigated in this docket. ICEA states that although true that the IPA does not itself set the ACP, the ACP is based on the renewable energy procurements that the IPA manages on behalf of the utilities. ICEA believes the instant docket discussing the Plan is the ideal forum in which to address concerns regarding that process, particularly when considering the fact that no alternative forum exists. (ICEA Reply at 8)

7. Commission's Conclusions

RESA requests that, in the future, if assumptions in the manner in which ACPs are calculated are changed, those changed assumptions should be made prospectively. RESA says if a changed assumption were reflected in the subsequent, rather than the current, compliance period, RESs would have some opportunity to adjust prices accordingly. Expressing similar underlying concerns, Exelon suggests that the maximum and estimated ACP rate, including assumptions, be published on a forward basis for the full time period of the Plan. If that is not possible or practicable, Exelon asks that all available components of this calculation be published and updated on a monthly basis, to enable ARES to make their own assessments and appropriately take into account those factors within their respective portfolios. ICEA supports the suggestions of RESA and Exelon.

WOW believes RESA's proposal and Exelon's primary proposal are in conflict with the Section 16-115D(d)(1) of the PUA. WOW suggests Exelon's alternative proposal is not. The IPA says it is not involved in setting the ACP rate, and the process of determining the ACP is not part of the Procurement Plan. As a result, the IPA does not believe this issue is appropriate for litigation in this docket. Similarly, Staff recommends that the Commission take no action in this docket in relation to RESA's concerns over the procedures for computing and announcing ACP rate estimates.

In its Reply, WOW contends the Commission could address the issue in this docket, or the matter could be put into another docket if the Commission prefers or if Staff thought that there was benefit to reviewing it in a separate docket. WOW believes that it is most expedient to address the issue in this docket. ICEA also believes the instant docket discussing the Plan is the ideal forum in which to address concerns regarding that process, particularly when considering the fact that no alternative forum exists.

Section 16-115D(d)(1) states in part:

> The Commission shall establish and post on its website, within 5 business days after entering an order approving a procurement plan pursuant to Section 1-75 of the Illinois Power Agency Act, maximum alternative compliance payment rates, expressed on a per kilowatt-hour basis, that will be applicable in the first compliance period following the plan approval. A separate maximum alternative compliance payment rate shall be established for the service territory of each electric utility that is subject to subsection (c) of Section 1-75 of the Illinois Power Agency Act. Each maximum alternative compliance payment rate shall be equal to the maximum allowable annual estimated average net increase due to the

> costs of the utility's purchase of renewable energy resources included in the amounts paid by eligible retail customers in connection with electric service, as described in item (2) of subsection (c) of Section 1-75 of the Illinois Power Agency Act for the compliance period, and as established in the approved procurement plan. Following each procurement event through which renewable energy resources are purchased for one or more of these utilities for the compliance period, the Commission shall establish and post on its website estimates of the alternative compliance payment rates, expressed on a per kilowatt-hour basis, that shall apply for that compliance period. Posting of the estimates shall occur no later than 10 business days following the procurement event, however, the Commission shall not be required to establish and post such estimates more often than once per calendar month. By July 1 of each year, the Commission shall establish and post on its website the actual alternative compliance payment rates for the preceding compliance year . . . .

The Commission has reviewed the arguments of the parties and it appears RESA's and Exelon's primary proposals are both inconsistent with the requirements of the PUA. It appears that the RESA and the primary Exelon proposals are effectively asking to delay paying the Actual ACP Rate by one year beyond what is required by the PUA. In any event, the Commission concurs with the IPA and Staff that all of the proposals regarding the ACP rate are beyond the scope of this proceeding and the Commission declines to adopt any such proposal in this proceeding. The Commission is, however, sympathetic to RESA and Exelon’s concern regarding the need for current and accurate ACP rate calculations, and would recommend that Staff post updates to these calculations in as timely a manner as possible, but not more than once a month, in accordance with Section 16-115D(d)(1).

D. Renewable Resources

1. Renewable Supplier's Position

The RS states in evaluating the bids for the LTPPAs in the December 2010 bundled renewable energy resources procurement, the IPA (through its Procurement Administrator), in consultation with Staff and the Procurement Monitor, developed and used a confidential 2010 forward energy price curve for the future period to be covered by the LTPPAs. This 2010 forward energy price curve contained a projected energy price for each year in the term of the LTPPAs. The RS says the IPA and the Commission used the 2010 forward energy price curve to calculate the imputed REC prices in the bidders’ proposals for the LTPPAs. The bid price for bundled renewable energy resources less the projected energy price from the forward energy price curve equaled the imputed REC price in a LTPPA bid proposal. The RS says the imputed REC prices were then compared to the statutory rate impact limits and to “benchmark” REC prices to determine if the REC purchases under the proposed LTPPAs would be “cost effective” as required by Section 1-75(c)(1) of the IPA Act. (RS Objections at 5-6)

According to the RS, the IPA also uses the imputed REC prices to determine if the RRB, and thus the statutory RPS rate impact limits, will be exceeded for each procurement year. The RS says the IPA uses only the imputed REC prices, and not the energy component of the LTPPAs, to determine if the RRB will be exceeded. The RRB is the statutory rate impact limit per kWh (0.18917 cents/kWh for ComEd and 0.18054 cents/kWh for AIC) times the kWh load of the eligible retail customers to be served by the electric utility for the year. The RS says the RRB amount for the electric utility is compared to the sum of the product of the imputed REC price under each of the LTPPAs for the year times the contract quantity under the LTPPA. If the RRB for an electric utility is less than the total calculated cost of the contracted RECs, the RS notes a curtailment of REC purchases under the LTPPAs is necessary in order to reduce the dollar amount of the REC purchases for the year to no greater than the RRB. The RS says neither the full bundled prices of renewable energy resources under the LTPPAs, nor the energy component of the LTPPAs, are considered in this calculation. The RS says this procedure for determining if the RRB would be exceeded in each year was specified in Appendix K to the IPA's 2010 Procurement Plan that the Commission approved in Docket No. 90-0373. (RS Objections at 6-7)

The RS states under that procedure, the energy component of the LTPPAs was not and is not assigned any unique or otherwise distinctive attributes as "renewable energy;" rather, the energy component has been assigned a pricing attribute equivalent to the "forecasted market price of electricity for each annual delivery year of the contract." The RS says all the pricing impact attributable to the renewable aspects of the bundled product is attributed to the RECs, not to the energy to be generated pursuant to the LTPPA. (RS Objections at 7)

The RS indicates it has previously expressed concerns to the IPA about the above-described procedure. Nevertheless, the RS claim it is proposing an approach to the determination and implementation of REC purchase curtailments to meet the RPS rate impact limits, and the settlement of the energy associated with the curtailed RECs, that is consistent with the procedures used by the IPA to determine whether the RRB will be exceeded in a year and whether curtailment of REC purchases under the LTPPAs is necessary. (RS Objections at 7)

The RS proposes that the IPA Plan should be revised to state, and the Commission should direct in its order, that only REC purchases under the LTPPAs, and not the energy portion of the LTPPAs, should be curtailed for the 2014-2015 procurement year. Correspondingly, the RS suggests the Commission should order that the energy component of the LTPPAs associated with the curtailed RECs should not be curtailed, but rather should be settled by the electric utilities based on the energy price from the 2010 forward energy price curve less the day-ahead hourly LMP for each hour. (RS Objections at 7-8, Reply at 2-3)

In the RS' view, this proposal flows directly from, and is the logical consequence of, the procedure the IPA uses to determine the imputed price of RECs under the LTPPAs and to determine if the RRB will be exceeded and a curtailment of REC purchases is needed. The RS says because the IPA's, and, ultimately, the Commission's, determination of whether the RRB will be exceeded is based solely on the REC purchase portion of the LTPPAs, using the imputed REC prices derived from the 2010 forward energy price curve, there is no basis for curtailing the energy portion of the LTPPAs. The RS says the energy component of the LTPPA, and the price of the energy component, does not in any way enter into the RRB/curtailment determination. The RS believes the energy component of the LTPPAs should not be curtailed. The RS also believes the electric utilities should be required to settle the energy portion of the LTPPAs associated with the curtailed RECs, on a monthly basis, based on the difference between the 2014-2015 energy price from the 2010 forward energy price curve (i.e., the same energy price used to determine the imputed REC prices and the need for and extent of a curtailment) and the day-ahead hourly LMPs. The RS claims this energy settlement procedure would be consistent with the settlement process under the LTPPAs, under which (absent a curtailment) the electric utility pays the LTPPA counterparty, on a monthly basis, an amount equal to the Contract Price less the day-ahead hourly LMP for all energy generated by the counterparty's renewable generation facility in each hour (up to the contract maximum quantity). (RS Objection at 8-9)

According to the RS, the energy portion of the LTPPAs has provided the electric utilities with an energy price hedge based on the 2010 forward energy price curve, and the electric utilities should be allowed to recover the cost of the hedge for the entire contract quantity of energy in each LTPPA, including the energy associated with the curtailed RECs, through their tariffs. The RS says the settlement process specified in the LTPPAs provides that the electric utility pays the renewable supplier, for each month, the Contract Price less the day-ahead hourly LMP for each hour for the energy generated in the month. Mathematically, the RS claims this means that the electric utility is paying for (i) RECs at the imputed REC price as determined using the 2010 forward energy price curve and (ii) the energy hedge cost, i.e., the difference between the energy price from the 2010 forward energy price curve and the actual day-ahead hourly LMP (that is, the difference between the market price of energy as projected in 2010 and the current market price of energy). The RS says both components of these payments are recoverable costs for the utilities as costs incurred to comply with an approved procurement plan. The RS states that under its proposal, the recoverable hedging cost for the contracted energy associated with curtailed RECs is the 2014-2015 energy price from the 2010 forward energy price curve, less the day-ahead hourly LMPs. (RS Objections at 9)

The RS asserts that under its proposal, the electric utilities (to the extent of their accumulated hourly ACP funds) and the IPA (using the RERF) would continue to purchase curtailed RECs at the imputed REC prices derived from the 2010 forward energy price curve (i.e., the same imputed REC prices used to make the RRB/curtailment determination), just as ComEd and the IPA are doing for the current procurement year and as the IPA Plan proposes that they continue to do for the 2014-2015 procurement year. (RS Objections at 9-10)

The RS contends its proposal is consistent with the provision of the LTPPAs relating to curtailments to meet the RPS rate impact limits. The RS says the LTPPAs allow the electric utilities to curtail purchases under the LTPPAs due to the operation of the RPS rate impact limits if so required by law, statute, or an order, rule or decision of the Commission. The LTPPAs further specify that "unless otherwise directed by the Illinois Commerce Commission or statute," the electric utility will reduce the quantity of RECs and the associated energy purchased under each LTPPA on a proportionate basis to the levels of purchases which are recoverable under the RPS rate impact limits. According to the RS, the Commission, in implementing curtailments under the LTPPAs in accordance with the RS' proposal, can "otherwise order" that only the REC purchases under the LTPPAs need to be reduced in order to stay within the RPS rate impact limits (i.e., for the RRB to not be exceeded), and the electric utilities can curtail their REC purchases under the LTPPAs by the percentage determined by the IPA and the Commission. (RS Objections at 10)

The RS states mechanically, the monthly contract settlements for the LTPPAs under the RS' proposal would be straightforward. The RS says the electric utility would pay the supplier for the amount of energy generated in each hour of the month (up to the original, full contract quantity) at the bundled contract price less the day-ahead hourly LMP (as provided for in the LTPPAs), but would deduct from the payments the product of the imputed REC price times the number of curtailed RECs for the period (determined using the curtailment percentage). (RS Objections at 10)

The RS says its approach would result in the following outcomes:

- As required by Section 1-75(c)(2) of the IPA Act, the RPS rate impact limits are not exceeded;
- REC purchases under the LTPPAs are curtailed to the extent necessary to prevent the RPS rate impact limits from being exceeded;
- The renewables suppliers are kept whole for the energy portions of their LTPPAs, including the energy associated with curtailed RECs, which is not considered in the RRB/curtailment determinations;
- The renewables suppliers are paid for, and the electric utilities are also kept whole by recovering through their tariffs, the cost of the energy hedges embodied in the LTPPAs; and
- Curtailed RECs are purchased by the electric utilities (using hourly ACP funds) and the IPA (using the RERF) at the same imputed REC prices used by the IPA to evaluate the LTPPA bid prices in the December 2010 procurement event and to determine the extent to which REC purchases must be curtailed to prevent the RPS rate impact limits from being exceeded.

(RS Objection at 10-11)

The RS claims a corollary benefit of its proposal is that, because the energy portions of the LTPPAs are not curtailed under this proposal, the energy associated with the curtailed RECs can (and should) be taken into account in determining whether and to what extent it is necessary to conduct additional energy procurements for the electric utilities to have sufficient contracted energy to serve the projected loads of the eligible retail customers for the 2014-2015 procurement year. The RS says LTPPAs are bundled contracts for the provision of energy from renewable energy resources and the associated RECs. The RS says this is true even though the LTPPAs are financially settled based on the difference between the bundled Contract Prices and the day-ahead hourly LMPs, without the energy generated by the renewables suppliers' facilities necessarily being delivered to the utilities. Although the LTPPAs are financially settled, the RS states the IPA Plan includes the contracted energy quantities under the LTPPA in the electric utilities' total contracted supplies for the 2014-2015 Procurement Year. According to the RS, the energy components of the LTPPAs do not need to be curtailed in order to prevent the RRB and the statutory RPS rate impact limits from being exceeded. In the RS' view, it makes no sense to treat the energy portion of the LTPPAs associated with the curtailed RECs as being curtailed, and then to procure additional energy from other sources (in part to replace the curtailed energy under the LTPPAs) in order to meet the electric utilities' total eligible retail customers' supply needs. (RS Objections at 11-12)

If the Commission were to determine that both REC purchases and the associated energy under the LTPPAs must be curtailed, then the RS suggest the electric utilities (using hourly ACP funds) and the IPA (using the RERF) should purchase curtailed RECs at a price equal to the bundled Contract Price less the day-ahead hourly LMPs. The RS says the resulting amount is the imputed value of the REC portion of the LTPPA under the terms of the contracts, with the day-ahead hourly LMPs comprising the energy value of the contract. The RS claims use of the bundled Contract Prices for energy plus associated RECs specified in the LTPPAs, which were the "winning bid prices" (Section 1-56(d) of the IPA Act) in the December 2010 procurement event for bundled renewable energy resources, less the hourly LMPs, to determine the prices at which the IPA will purchase curtailed RECs, would appropriately base the IPA's purchase of curtailed RECs on "the winning bid prices paid for like resources procured for electric utilities required to comply with Section 1-75 of this Act" as specified in Section 1-56(d) of the IPA Act. (RS Objections at 12)

The RS states based on the procurement process set forth in Appendix K to the IPA's 2010 Procurement Plan and approved by the Commission in Docket No. 09-0373, the "bid prices" of the LTPPAs for bundled renewable energy resources were required to be submitted on a bundled, single-price basis for both the electricity from the renewable generating resource and the associated RECs. The RS says Appendix K specified that "the contract terms will be standardized and winning bids will be selected on the basis of price alone." The RS says bidders were required to submit bids for the LTPPAs on the basis of a single, bundled price for energy from renewable resources and the associated RECs beginning with the 2012-13 procurement year. (RS Objections at 12-13)

According to the RS, the procurement process specified in Appendix K, and memorialized in the form LTPPAs developed by the IPA, which the bidders were required to accept without negotiation, specified that deliveries under the LTPPAs will be financially settled on the basis of the Contract Price less the day-ahead hourly LMPs:

> The delivery of energy will be accomplished through a fixed for floating financial swap. **The fixed price for the swap will be the full bundled contract price for the renewable PPA. The floating price will be the Locational Marginal Price ("LMP") at the utility's load zone for each hour in the day-ahead market of the applicable Regional Transmission Organization**. . . . Seller will provide hourly-integrated generation meter data (from a revenue quality meter that satisfies RTO requirements) on a day after basis to the utilities and the IPA to enable them to perform the necessary calculations. For all energy produced by the applicable percentage of the seller's specified unit(s), the utilities will calculate the difference between the hourly LMP in the day-ahead market for their zone, and the Contract Price. **The price differences will be multiplied by the applicable percentage of the volume of energy produced by the specified unit(s) in each hour. For every hour that the unit(s) produced energy, if the LMP in the day ahead market at the utility's zone is less than the Contract Price, the utility will pay the seller the difference in these costs multiplied by the quantity of energy produced by the unit(s) multiplied by the bid percentage related to the output from the relevant generating unit.** For every hour that the unit(s) produced energy, if the LMP in the day-ahead market at their zone is higher than the Contract Price, the seller will pay the utility the difference in these costs multiplied by the quantity of energy produced by the unit(s) multiplied by the bid percentage related to the output from the relevant generating unit. The net of the positive and negative payments will be settled on a monthly basis.

(RS Objections at 13, citing Appendix K at 4; emphasis added.)

The RS says the "winning bid prices" under the LTPPAs were the single, bundled Contract Price for energy and the associated RECs bid by each of the successful bidders. From the suppliers' perspective, the RS says the price to be received for the RECs associated with the energy generated in each hour is the bundled Contract Price less the day-ahead hourly LMP (i.e., the market price of energy) for each hour. (RS Objections at 13-14)

The RS argues that implementation of its proposal would not violate the terms of the LTPPAs but rather would be consistent with the terms of the LTPPAs. The RS says the relevant provision of the LTPPA, which is Section D, Payment Obligations, in the "Confirmation" portion of the LTPPAs, states in relevant part:

> Buyer is allowed to recover all costs and other amounts incurred under this Confirmation and the Master Agreement from its customers pursuant to a pass-through tariff that is authorized by section 16-111.5(l) of the

> Illinois Public Utilities Act (220 ILCS 5/16-111.5(l)) and approved by the Illinois Commerce Commission. Notwithstanding anything to the contrary in this Confirmation or the Master Agreement, Buyer shall not be liable to Seller for any amounts, including any Early Termination Amounts that might otherwise be due under Section 6(e) of the Master Agreement, that Buyer is not allowed to or cannot recover, for whatever reason, from its customers through those pass-through tariffs.
>
> **Unless otherwise required by law, statute or an order, rule or decision of the Illinois Commerce Commission**, Buyer will not refuse to pay for any Product delivered by Seller for the sole reason that payment for Product would cause the cost caps provided for in Section 1-75(c)(2) of the Illinois Power Agency Act (20 ILCS 3855/1-75(c)(2)) to be exceeded. **In the event that Buyer is not allowed to recover any costs as a result of any of the above actions**, the following additional conditions shall apply: 1) Buyer shall inform seller as soon as practical of the law, statute or order, rule or decision of the Illinois Commerce Commission limiting costs recovery; 2) **unless otherwise directed by the Illinois Commerce Commission**, Buyer shall reduce the quantity of Product purchased under all contracts for renewable energy resources that allow for pro-ration in this circumstance and that are effective and in force at the time by reducing proportionately for each contract the Annual Contract Quantity or similar contract term as required such that the amount of expenditures for Product are recoverable; and 3) Buyer will provide notice to Seller each time a change is made to the Annual Contract Quantity under this provision.
> (RS Reply at 3-4, emphasis added)

The RS argues under this provision, the electric utility cannot curtail purchases under the LTPPAs unless it is authorized to do so by an order of the Commission that specifies the extent to which purchases would cause the cost caps of Section 1-75(c)(2) to be exceeded. The RS says any reduction in purchases must be as and to the extent directed by the Commission's order. The RS claims the "default" implementation of the reduction in purchases under this provision is a reduction in the quantity of "Product" to be purchased by the utility, unless, however, otherwise directed by the Commission. (RS Reply at 4)

According to the RS, the terms of the LTPPA rely on an order of the Commission to determine whether and to what extent the utility may reduce purchases under the LTPPA to prevent the cost caps from being exceeded (i.e., to direct a curtailment), and rely on the Commission order to determine the manner in which the curtailment shall be implemented. The RS maintains the IPA (and the Commission) determine whether the RRB and the cost caps of Section 1-75(c)(2) are exceeded based solely on the imputed price of RECs in the LTPPAs; therefore, in order to prevent the cost caps from being exceeded, it is sufficient for the Commission to order a reduction of purchases of RECs, in the appropriate amount, under the LTPPAs. The RS asserts there is no basis for curtailing the energy portion of the LTPPAs since the energy component is not considered in determining whether the cost caps will be exceeded and whether a curtailment is needed to prevent the cost caps from being exceeded. The RS believes the Commission can and should direct that only purchases of RECs should be curtailed to prevent the cost caps from being exceeded. The RS says the LTPPA then requires the utility (and the Seller) to implement the curtailment in accordance with the terms of the Commission's order. (RS Reply at 4)

According to the RS, ComEd's argument that the term in the above provision, "unless otherwise directed by the Illinois Commerce Commission," only allows the Commission to direct that the reduction be implemented on something other than a pro rata basis among all LTPPA suppliers, is made of whole cloth and is an unreasonably restrictive construction of the contract terms. The RS argues the term "unless otherwise directed by the Illinois Commerce Commission" does not modify solely the phrase "by reducing proportionately for each contract the Annual Contract Quantity," but rather modifies the entire clause, "Buyer shall reduce the quantity of Product purchased under all contracts for renewable energy resources that allow for pro-ration in this circumstance and that are effective and in force at the time by reducing proportionately for each contract the Annual Contract Quantity or similar contract term as required such that the amount of expenditures for Product are recoverable." The RS asserts the provision contemplates that the Commission can "direct" a reduction of something "other" than "the quantity of Product purchased" so that the amount of expenditures are recoverable. The RS claims the Commission can direct that only the purchase of RECs should be reduced in the amount needed to stay within the RPS cost caps of Section 1-75(c)(2) of the IPA Act. (RS Reply at 4-5)

The RS asserts that contrary to ComEd's argument at page 5 of its Response, it is not arguing that the phrase "unless otherwise directed by the [Commission]" authorizes the Commission to rewrite material terms of the LTPPAs. Rather, the RS claims it is a material term of the LTPPA that the Commission is to specify the nature, extent and terms of any curtailment. The RS contends its proposal is based on the parties implementing a curtailment in accordance with the Commission's directions, as required by the terms of the LTPPAs. (RS Reply at 5)

The RS believes the fact that Appendix K to the IPA's 2010-2011 procurement plan adopted in Docket No. 09-0363 specified that "Product" in the LTPPAs would be the RECs plus associated energy does not further support ComEd's argument. The RS acknowledges that the LTPPAs define "Product" as RECs plus the associated energy. The RS contends this definition merely begs the question of the extent, under the terms of the LTPPAs, of the Commission's authority to order and define the scope of a curtailment and the parties' obligation to implement the curtailment as ordered by the Commission. The RS insists the terms of the LTPPAs allow the Commission to direct that a reduction of purchases to meet the cost caps be implemented through a reduction of REC purchases in the necessary amount, rather than solely through a reduction of purchases of RECs plus the associated energy. (RS Reply at 5-6)

The RS also asserts contrary to ComEd's argument, the options available to the Seller under the LTPPA in the event of a curtailment are still available under the RS' proposal. The RS says the Seller can elect, upon being notified of a curtailment and its terms, to terminate the LTPPA, to accept the curtailment for the procurement year, or to accept the curtailment on a permanent basis for the remaining term of the LTPPA. (RS Reply at 6)

In considering the other parties' contractual arguments, the RS asserts it is important to keep in mind that the LTPPAs were not negotiated at arms-length between the utilities and the suppliers. The RS says, as required by Section 16-111.5(e)(2) of the PUA, the terms of the LTPPAs were developed by the IPA's procurement administrator "subject to Commission oversight," and "the terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contracts in advance so that winning bids are selected solely on the basis of price." According to the RS, the procurement administrator was to "consult[ ] with the utilities, the Commission, and other interested parties." The RS says Section 16-111.5(e)(2) specifies that "if the procurement administrator cannot reach agreement <u>with the applicable electric utility</u> as to the contract terms and conditions, the procurement administrator must notify the Commission and the Commission shall resolve the dispute". The RS claims there is no corresponding right provided for potential suppliers or successful bidders to raise issues as to the contract terms and have the Commission resolve the dispute. (RS Reply at 6)

The RS argues this is not like a situation, as ComEd would have it, in which a court is adjudicating a dispute over the interpretation of a contract between two commercial parties who negotiated the terms of the contract at arms-length. The RS asserts there is no "intent of the parties" to be construed with respect to the RS' proposal because the LTPPAs were not the product of arms-length negotiations. The RS says the LTPPAs are a statutorily- and regulatorily-directed construct that the PUA specified the bidders were required to accept, without "negotiations by winning bidders." The RS believes it is entirely consistent with the genesis of the LTPPAs that they authorize the Commission to determine the nature, extent and means of implementation of a curtailment in order to stay within the cost caps, and require the parties to implement the curtailment in accordance with the Commission's directive. (RS Reply at 7)

The RS asserts while other parties argue that the RS' proposal is inconsistent with the terms of the LTPPAs, the entire process for calculating imputed REC prices using a forward energy price curve developed by the IPA Procurement Administrator in 2010, and using the imputed REC prices to determine whether and to what extent the RRB is exceeded and a curtailment of the LTPPAs is needed, is completely outside the terms of the contracts and is based on information that is also outside the terms of the contracts and was not made known to the RS at the time they bid on and entered into the LTPPAs. The RS believes the proposal that only purchases of RECs (at the IPA's imputed REC price) should be curtailed in order to stay within the cost caps, and that the parties should continue to settle the energy associated with the curtailed RECs based on the energy prices in the IPA's 2010 forward energy price curve, is completely consistent with and flows directly from the method adopted by the IPA and the Commission to price RECs under the LTPPAs and to determine whether the RPS cost caps are exceeded and a curtailment of the LTPPAs is needed. (RS Reply at 7)

While other parties argue that the RS' proposal inappropriately segments "Product" under the LTPPAs into RECs and the associated energy for purposes of implementing a curtailment of purchases, the RS contends it is the methodology adopted by the IPA and the Commission, using projected energy prices and derived, imputed REC prices that are not part of the contracts, that has already segmented the LTPPAs into a REC component and an energy component. The RS also asserts the other parties have proffered no response to the RS' demonstration that, since the determination of whether and to what extent the RRB is exceeded and a curtailment of purchases is needed is based solely on the imputed REC prices derived from the IPA's 2010 forward energy price curve, there is no justification for curtailing both the REC portion and the energy portion of the LTPPAs. (RS Reply at 7-8)

Apart from their arguments based on the terms of the LTPPAs, the RS says the utilities make two other arguments concerning its proposal. The first is that the RS' proposal would violate Section 16-111.5(e)(3) of the PUA because it would result in the utilities purchasing electricity at prices that have not been evaluated through benchmarks. The RS claims under its proposal, the utility would purchase (or financially settle) the electricity associated with curtailed RECs using precisely the electricity price developed by the IPA (the 2010 forward energy price curve) to "benchmark" bids for the LTPPAs in the 2010 long-term procurement event and contract award. (RS Reply at 8)

The RS says the utilities also argue that its proposal for settling the energy portion of the LTPPAs associated with curtailed RECs will adversely impact their eligible retail customers because the eligible retail customers will have to pay the difference between the current market price of energy (the day-ahead LMPs) and the energy prices in the IPA's 2010 forward energy price curve. The RS says it is correct that, based on current market prices, its proposal for settling the energy associated with curtailed RECs under the LTPPAs would result in the utilities' eligible retail customers being charged for the difference between the current year energy price from the 2010 forward energy price curve and the day-ahead LMPs. The RS indicates the current year energy price from the 2010 forward energy price curve is higher than the day-ahead LMPs. The RS insists the payment of this amount is consistent with the terms of the LTPPAs and with the IPA's evaluation of the bid prices at the time of contract award using the 2010 forward energy price curve. The RS claims the LTPPA pricing incorporates a price hedge that energy supplied under the LTPPAs will not exceed the current year's price included in the 2010 forward energy price curve. The RS says if, in a future year, the day-ahead LMPs were to exceed that year's energy price in the 2010 forward energy price curve, the eligible retail customers energy costs under the LTPPAs would be capped at the energy price included in the 2010 forward energy price curve. In that situation, the RS would bear the difference. The RS claims through the LTPPA pricing and settlement terms, the eligible retail customers have paid for a hedge, or insurance, against energy prices rising above the current year energy price included in the 2010 forward energy price curve. (RS Reply at 8-9)

Given that the determination of whether and to what extent the RPS rate impact limits are exceeded is addressed solely through analysis of the imputed REC prices (and curtailment of REC purchases if needed) under the LTPPAs, the RS asserts there is no reason for customers to stop paying for the energy hedge on the energy associated with curtailed RECs under the LTPPAs. The RS also claims while the market price of electricity currently is less than the current year price of electricity in the IPA's 2010 forward energy price curve, the LTPPAs are long-term contracts, and it is possible that in future years, the market price of electricity will exceed the price of electricity in the 2010 forward energy price curve. In that circumstance, the RS says under its proposal, the settlement of the energy associated with curtailed RECs would require a payment by the LTPPA Sellers to the utility, which would reduce the utility's charges to its eligible retail customers. (RS Reply at 9-10)

The RS asserts its proposal is no different than what would transpire if the utilities, through an IPA procurement event, had entered into multi-year contracts for the purchase of non-renewable resource electricity but the current market price of electricity was now below the contract price. The RS claims the utilities would not be contending that electricity purchases under the long-term contracts should be curtailed or terminated because the current market price is now lower than the contract price. (RS Reply at 10)

The RS states under its proposal the contracted energy associated with the curtailed RECs is available in determining whether the utilities need to engage in additional procurements to meet the projected load of their eligible retail customers in the 2014-2015 procurement year. The RS believes there is no justification for curtailing the energy portion of the LTPPAs associated with curtailed RECs while at the same time engaging in new procurement events and entering into new electricity supply contracts to meet the loads of the utilities' eligible retail customers in the procurement year. (RS Reply at 10)

The RS believes as a second best alternative to its primary proposal, the IPA Plan should be revised to specify that the utilities (using hourly ACP funds) and the IPA (using RERF monies) will purchase curtailed RECs under the LTPPAs at a price equal to the LTPPA Contract Price less the day-ahead hourly LMPS for the energy associated with the curtailed RECs. The RS claims this approach is a second-best alternative to its primary approach because, unlike the preferred approach, the alternative approach is not a direct and logical consequence of the method that has been established and used by the IPA to determine imputed REC prices under the LTPPAs and to determine if the RPS rate impact limits are exceeded. However, the IPA asserts the alternative approach is based directly on the pricing and settlement terms of the LTPPAs. The RS says the alternative approach, like its preferred approach, would enable the LTPPA suppliers to be kept whole under their contracts through the combination of settlements according to the contract terms for the non-curtailed portion of their contracts and purchases of curtailed RECs by the utilities and the IPA. (RS Objections at 14, Reply at 10-11)

The RS says adoption of the alternative approach would require deletion of the following sentence at the end of the second paragraph of Section 8.3.1, "Use of Hourly ACPs Held by the Utilities," on page 105 of the IPA Plan: "As approved by the Commission in Docket No. 09-0373, the imputed REC price under the bundled contracts is equal to the difference between the Contract Price and the forward price curve for each respective load zone for a particular year, as developed by the Procurement Administrator in 2010." The RS states the deleted sentence would be replaced with: "The imputed REC price for the purpose of the purchase of curtailed RECs is the difference between the Contract Price and the day-ahead hourly LMP for each load zone for each hour." (RS Objections at 14-15)

The RS notes Staff and AIC find this proposal unacceptable because it would result in varying prices throughout the year for the curtailed RECs to be purchased by the utilities using hourly ACP funds and by the IPA using the RERF; and because it would likely result in purchase prices for the curtailed RECs that are higher than the imputed REC benchmark prices developed by the IPA using the 2010 forward energy price curve. The RS claims the utilities' and Staff's responses to its primary and alternative proposals are inconsistent with each other. The RS says the utilities and Staff object to its preferred approach because, they contend, it is not consistent with the terms of the LTPPAs, which itself is not specified in the LTPPAs; but then they object to the alternative proposal – which bases the purchase price of curtailed RECs solely on the terms of the LTPPAs – because it could result in purchase prices for curtailed RECs that exceed the imputed REC prices, which were determined outside the terms of the LTPPAs. The RS says if the parties and the Commission are concerned that the pricing of curtailed RECs should be determined solely and directly from the terms of the LTPPAs, then the only REC price that can be determined from the terms of the LTPPAs is the full contract price less the day-ahead LMPs. The RS says the day-ahead LMPs are the market price of energy specified in the LTPPAs and the difference between the price of energy and the full contract price is the value of the REC. (RS Reply at 11-12)

ComEd argues that the alternative proposal would require its eligible retail customers to indirectly "subsidize" the RS, and also asserts that the alternative proposal would increase the price ComEd hourly customers pay for RECs. The RS believes these arguments are incorrect. Under the alternative proposal, the RS says neither the utilities nor their hourly pricing customers, nor their eligible retail customers as a group, would be "subsidizing," or even paying incrementally for, the curtailed RECs. The RS claims utilities would only purchase curtailed RECs using the ACPs previously accumulated in respect of sales to their hourly pricing customers (as ComEd is doing during the current procurement year pursuant to the Commission's order in Docket No.12-0544). The RS says the IPA Act expressly directs that these accumulated hourly ACP funds are to be used to purchase renewable energy resources in the following year. The RS says the IPA would purchase curtailed RECs using RERF monies, which, per the PUA, are accumulated through ACPs made by ARES in respect of sales to their customers, who, obviously, are not the utilities' eligible retail customers. The RS believes, contrary to ComEd's argument, its alternative proposal would not result in any increased charges to the utilities' retail customers. (RS Reply at 12)

ComEd also argues that its customers would clearly not benefit from enabling the LTPPA suppliers to be kept whole, while AIC states that its customers would not benefit from the RS' proposals. The RS strongly disagrees with this contention. The RS says it can be presumed that the General Assembly enacted the RPS because it believed that inclusion of significant renewable resources in the state's electricity supply portfolio would benefit the public of this State, including its retail electricity consumers, and would provide an incentive for the construction of renewable energy generating facilities in Illinois. The RS claims those incentives are manifested in the LTPPAs that resulted from the 2010 long-term procurement event, as several renewable energy generation projects were developed on the basis of the LTPPAs the suppliers entered into. The RS says the present situation in which the LTPPAs are curtailed and the suppliers under those contracts receive less than their full contracted revenues – which are the consequences of well-intentioned statutory and policy changes (specifically the authorization and implementation of municipal aggregation programs) – creates a strong disincentive to the development and construction of new renewable resource generating facilities in Illinois, which has slowed considerably (there are currently no projects under construction in Illinois). The RS contends either its preferred proposal or its alternative proposal would remove this disincentive. (RS Reply at 12-13)

The IPA also states that the question of using hourly REC prices for curtailed RECs is outside the scope of this proceeding to the extent that it relates to payments from the Renewable Energy Resources Fund. The RS says it recognizes that the Commission does not have jurisdiction to direct the IPA to purchase curtailed RECs using RERF monies nor to direct the price at which the IPA purchases curtailed RECs. However, the RS hopes that, for consistency, the IPA will use the same pricing approach for the purchase of curtailed RECs with RERF monies that is adopted for the purchase of curtailed RECs using hourly ACP funds. (RS Reply at 13)

2. The IPA's Position

The RS argues that any curtailment of the LTPPAs should only be for RECs, and not energy. (IPA Response at 11, citing RS Objections at 5-12) The IPA takes no position on this matter, but notes that to its knowledge both RECs and energy were curtailed in Delivery Year 2013-14. However, the IPA further notes that the Commission did not explicitly rule on whether energy was part of the LTPPA in the 2013 Procurement Plan approval order. Finally, the IPA notes that the question of using hourly REC prices for curtailed RECs is outside the scope of this proceeding to the extent that it relates to payments made from the Renewable Energy Resources Fund. (IPA Response at 11)

The IPA took no position in its Response to Objections on the RS' argument that even when RECs are curtailed, the associated energy should not be curtailed. However, after reviewing the Responses - particularly from Staff and ComEd - the IPA is concerned that the RS are seeking to “rewrite the contract” outside the procurement process. If the Commission finds Staff, AIC, and ComEd’s arguments that the contract provides for curtailment of energy as well as RECs, the IPA strongly urges the Commission to require all parties to adhere to the terms of the contract. If the Commission is perceived to allow a mid-performance rewrite of the contract, the IPA is concerned that future aggrieved suppliers will attempt to have the Commission “rewrite” their contracts and allow the supplier to continue service at the same price but subject to more favorable terms. The IPA is concerned that this would undermine the bidding process. (IPA Reply at 8)

3. AIC's Position

AIC notes that RS states that the implementation of curtailments of purchases under long-term power purchase agreements has resulted in a shortfall of revenues compared to the revenues associated with LTPPAs that were not curtailed. RS argues that while the use of ACP funds has provided a source of lost revenue pertaining to RECs, lost revenue associated with energy should be addressed. RS then proposes two alternatives by which the perceived shortfall of revenues would be eliminated. (AIC Response at 4-5)

For clarification purposes, AIC notes the 2013 plan year resulted in partial curtailments of LTPPAs for ComEd only, whereas the current Plan also recommends partial curtailment of AIC LTPPAs beginning in the 2014 plan year. In short, AIC disagrees with both recommendations. (AIC Response at 5)

AIC asserts the first proposal is contrary to the language in the approved and executed contracts, conflicts with the statute, and would result in an unjustified penalty to eligible retail customers. AIC claims the second proposal desires for AIC (using ACP funds) and the IPA (using RERF) to purchase curtailed RECs at a price higher than the implied REC price associated with the executed contracts. (AIC Response at 5-6)

Regarding the first proposal, AIC contends the language in the LTPPAs illustrates that the product is a bundled energy and REC product termed Annual Contract Quantity Commitment. AIC says the LTPPAs continue by stating that in the event the Commission approves curtailment (e.g., because the renewable rate cap for eligible retail load has been exceeded), then the proportional curtailment should also be for the Annual Contract Quantity Commitment. (AIC Response at 6)

In AIC's view, this language makes clear that any curtailment pertains to the bundled energy and REC product defined in the LTPPAs as Annual Contract Quantity Commitment. AIC claims the first proposal by the RS attempts to circumvent a key customer protection in the executed contracts and a protection for which the IPA has correctly requested the Commission invoke via curtailment of the bundled product. AIC contends this provision was intentionally added as a mechanism to protect eligible retail customers in the event the renewable cap was exceeded. AIC also says the language was fully vetted in workshops, agreed upon by the various parties, approved by the Commission and subsequently executed by AIC and the suppliers under the LTPPAs. AIC claims the proposed retroactive change to the terms of an existing contract is also inconsistent with the forward looking nature of the Plan. (AIC Response at 6)

AIC also believes the first proposal appears to be unlawful since Section 16-111.5(e) of the PUA makes clear that benchmarks are to be established for evaluating final prices in the procurement process and a request for proposal must be issued which includes sealed bidding and a provision for selection of bids based on price. If the Commission were to adopt the proposal that only RECs be curtailed but the energy would be settled, then AIC says it would mirror an energy only procurement as described in the statute. AIC claims this would be in conflict with Section 16-111.5(e) because renewables suppliers would be rewarded an energy only settlement that was never subject to the competitively defined process intended for IPA procurements. (AIC Response at 6-7)

In addition to circumventing the executed contracts and being contrary to the statute, AIC argues the first proposal would result in higher costs to eligible retail customers since they would be the ones directly responsible for paying for what RS describes as lost revenue under the LTPPAs. While AIC takes no position at this time regarding the IPA proposal to use ACP funds collected from hourly priced customers to partially offset lost revenues from the REC portion of the bundled product, AIC believes it is clear that eligible retail customers would not be financially harmed since funds already collected from hourly priced customers (but not spent) are being utilized. By contrast, because the first proposal is incremental in nature, AIC argues it would result in higher costs to eligible retail customers. AIC says the RS is asking the Commission to cast aside a key contractual provision which would result in eligible retail customers paying higher costs solely for the benefit of renewables suppliers and with no reciprocating benefit to eligible retail customers. Instead, eligible retail customers would be financially harmed. (AIC Response at 7)

AIC says the RS' second proposal is based on a scenario where the Commission determines that the bundled product under the LTTPAs is to be curtailed, but then the electric utilities (using hourly ACP funds) and the IPA (using the RERF) should purchase curtailed RECs at a price equal to the bundled Contract price less the day-ahead hourly LMPs. AIC claims this proposal would result in payment to renewables suppliers at a REC price which is higher than the implied REC price associated with the executed contracts. AIC suggests doing so would appear to be in violation of the statute which requires a process of benchmarking, request for proposals, sealed bidding and selection of winners based on price. (AIC Response at 7-8)

AIC maintains the RS' first proposal is in conflict with the executed LTPPAs, is contrary to the statute, and would result in higher costs to eligible retail customers with no benefit in return. AIC strongly recommends the Commission reject the proposal.

AIC also maintains that the RS' second proposal appears to violate procurement protocol as described by the statute. For these reasons, AIC recommends the Commission reject both proposals by the RS. (AIC Response at 8, Reply at 3)

4. WOW's Position

WOW notes the RS' first two objections relate to the appropriate manner for them to be compensated for their RECs that would be curtailed. WOW supports these objections and proposed resolutions of the RS. (WOW Response at 5)

5. Staff's Position

Staff states when the long-term power purchase agreements were developed, it was deemed reasonable to enlist the IPA's procurement administrator to estimate the cost of an otherwise identical standard energy procurement. Staff says that estimate was in the form of a forward price curve, by year, for a hypothetical constant supply of energy ("around-the-clock") throughout the 20-year period of the proposed LTPPAs. According to Staff, for wind farm suppliers bidding for the LTPPAs, the forward price curve was adjusted by a factor of 0.98 to take into account the historical tendency for wind farms to produce energy at times where the energy is, on average, 98% that of the simple average price of energy in the spot market. For solar photovoltaic farms, Staff says the forward price curve was adjusted by a factor of 1.2 to take into account the historical tendency for solar photovoltaic farms to produce energy at times where the energy is, on average, 120% that of the simple average price of energy in the spot market. Staff indicates the IPA proposed that, each year, it would be assumed that the portion of the upcoming year's total RPS budget expended just on the LTPPAs would be equal to the sum of the products of (a) each LTPPA's annual contract quantity, and (b) the difference between the LTPPA's contract price in that year and the around-the-clock price for that year taken from the forward price curve developed by the IPA's procurement administrator in 2010, adjusted by a factor of 0.98 or 1.20. Staff states by that measure, in plan year 2012-2013, the LTPPAs were expected to increase AIC customers' bills by $7.5 million and ComEd customers' bills by $21.6 million. (Staff Response at 11-12)

Staff believes the Commission cannot rewrite the contracts with AIC and ComEd without a competitive bid process. (Staff Response at 12)

Staff notes as a second-best alternative to the proposal, RS suggests the IPA Plan should be revised to specify that the utilities and the IPA will purchase curtailed RECs at a price equal to the Contract Price under the LTPPA less the day-ahead hourly LMPs. Staff says in Docket No. 12-0544, the Commission noted that "ComEd believes that the accumulated hourly ACP funds should be used by ComEd to purchase RECs from the long-term renewable contract counterparties at the applicable imputed REC prices that the IPA is asking the Commission to reaffirm in its Plan." Staff states those "applicable imputed REC prices" were those derived by subtracting from each LTPPA supplier's bundled contract price the price from the forward curve developed by the IPA's procurement administrator in 2010. Staff indicates the Commission approved this approach. (Staff Response at 12-13)

Staff states among other things, the Commission-approved approach left an absolutely certain liability for the utilities (and ratepayers), since the REC quantities and REC prices would be known at the time the new contracts were executed. In contrast, Staff says the RS proposal to use highly variable and uncertain spot prices for settlement purposes would leave ratepayers exposed to considerable risk, if spot prices were to fall. Staff believes this is especially risky for AIC customers, since under the current base forecast, without purchasing any other contracts, AIC will already be significantly over-hedged in all non-summer months and some summer months. (Staff Response at 12-13)

In its Reply Brief on Exceptions, Staff states that if the Commission does approve the RS proposal, then the Commission should also require the utilities to limit their actual expenditures on new unbundled RECs to the level of funds available from ACP revenues collected from the utilities' hourly customers. Staff claims this would be a simple matter of requiring the utilities to draft a contract that prevents further purchases once those funds have been exhausted. (Staff RBOE at 4-5)

According to Staff, for both AIC and ComEd customers, the RS' proposal is contrary to the interest of ratepayers because it will almost surely result in payments for RECs that exceed those under the IPA's pricing proposal, which is the same as the proposal that the Commission approved in Docket No. 12-0544. (Staff Response at 13-14)

In its Reply, Staff notes WOW supports the two positions taken by the RS concerning curtailment of quantities under their long-run power purchase agreements WOW also supports the position of the RS concerning review and approval of the spring load forecasts. Staff maintains the RS' recommendations cannot be adopted. (Staff Reply at 2-3)

According to Staff, WOW fails to add supporting evidence for the RS' positions. Staff also claims the response filed by WOW includes inaccurate information. (Staff Reply at 3)

Staff asserts the values shown by WOW for the ComEd "price to compare" are incorrect, since they do not include the PJM Services Charges (0.914 cents per kWh) or the PEA Factors, which averaged 0.205 cents per kWh from June 2013 through September 2013 and 0.500 cents per kWh between October and November. Taking these factors into account, Staff contends it is not true that an average ARES rate of 5.08 cents per kWh would be greater than ComEd's rate, as WOW states. Staff asserts ComEd's rate would be 13% greater in the summer months and 18% greater in the non-summer months of the June 2013-May 2014 plan year. Even assuming that the PEA drops to zero for the remainder of the 2013-2014 plan year, Staff says ComEd's non-summer rate would still average 11% greater than an average ARES rate of 5.08 cents per kWh. Additionally, according to Staff's calculations, the average rate offered by ARES to local governments in the ComEd territory is only 5.057 (rather than 5.08) cents per kWh. On the other hand, Staff says since this is not a load-weighted average, arguably, the larger cities are under-represented by the simple average. For example, Staff says the "muni-agg" rate offered by Integrys Energy Services to Chicago customers through May 2014 is 5.42 cents per kWh, but this is still less than both the summer and non-summer rates currently charged by ComEd. (Staff Reply at 3-4)

Staff believes the Commission should reject the recommendations provided by the RS and WOW. (Staff Reply at 4)

6. ComEd's Position

ComEd says citing to declining revenues, the RS propose in their Objections that the Commission significantly modify the manner in which purchases of renewable energy resources are curtailed under the LTPPAs to comply with the statutory price impact limit. Specifically, the RS would change the curtailment process approved in last year's plan such "that only the REC purchase portion of the LTPPAs, and not the energy component, should be curtailed." ComEd insists this proposal must be rejected as it violates the agreed-upon and Commission-approved terms of the LTPPAs and would impose an unreasonable burden on customers. ComEd asserts the utilities are purchasing renewable energy resources that are defined under the LTPPAs as energy that includes the associated renewable energy credit. ComEd claims the utility is not purchasing energy and RECs as separate and distinct products, and cannot purchase one without the other under the LTPPAs. If the cost of purchasing renewable energy resources under these contracts causes the rate impact cap to be exceeded, ComEd contends the contracts specifically call for the utility to curtail purchases of what is being delivered under the contract, i.e.; bundled energy and RECs. ComEd argues that the RS' proposal to rewrite the LTPPAs is improper, illegal, and must be rejected. (ComEd Response at 1-2)

ComEd indicates the agreements at issue are the product of the 2010 procurement plan (Docket No. 09-0373), wherein the Commission approved the IPA's proposal to procure long-term renewable energy resources by way of 20-year power purchase agreements known as LTPPAs. ComEd says the statutory basis for including the procurement of renewable energy resources in a procurement plan is Section 1-75(c) of the IPA Act, which establishes a statewide Renewable Portfolio Standard. This provision states that "procurement plans shall include cost-effective renewable energy resources," and includes a schedule setting forth "the percentage of cost-effective renewable energy resources" to be acquired over time. It also establishes an annual "cap" wherein the total renewable energy resources are to be "reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources" to specified limits. ComEd says the IPA's Plan properly recognizes that by virtue of this rate cap, curtailment of LTPPAs will be necessary during the 2014-2015 procurement year. (ComEd Response at 2-3)

ComEd states that among the terms of each LTPPA – which the IPA's Procurement Administrator developed in consultation with interested parties and the renewable suppliers agreed to in advance of submitting bids – are a precise definition of the item being purchased and sold and a detailed description of the manner in which the delivery amounts must be curtailed in the event the rate cap limitation is triggered. According to ComEd, the curtailment of RECs alone, as proposed by the RS, is neither allowed nor contemplated under the LTPPAs between ComEd and the RS. ComEd contends the lawful and agreed-to approach requires the curtailment of "Product," which is defined to include both the RECs and energy. ComEd states in the event the rate cap is exceeded, the contract terms require the following process be followed:

> 2) unless otherwise directed by the Illinois Commerce Commission or statute, Buyer shall reduce the quantity of Product purchased under all contracts for renewable energy resources that allow for pro-ration in this circumstance and that are effective and in force at the time by reducing proportionately for each contract the Annual Contract Quantity or similar contract term as required such that the amount of expenditures for Product are recoverable; and 3) Buyer will provide notice to Seller each time a change is made to the Annual Contract Quantity under this provision. Each time Seller receives a notice from Buyer pursuant to clause (3) of the preceding sentence, Seller shall have thirty (30) days thereafter to provide notice to Buyer of (a) its election to terminate this Agreement effective no later than 60 days after Seller's notice to Buyer of such election; (b) its election to reduce permanently the Annual Contract Quantity to the reduced level contained in Buyer's notice effective when the reduction is scheduled to take place; or (c) its election to accept the reduced Annual Contract Quantity contained in Buyer's notice for that Delivery Year. In the event that the Seller accepts the reduced Annual Contract Quantity contained in Buyer's notice pursuant to clause (c) of the immediately preceding sentence, the Applicable Percentage shall be reduced proportional to the reduction in the Annual Contract Quantity for that Delivery Year. In the event that the Seller accepts the reduced Annual Contract Quantity contained in Buyer's notice pursuant to clause (b) above, the Applicable Percentage shall be reduced proportional to the reduction in the Annual Contract Quantity.
> (ComEd Responses at 3-4, emphasis added)

ComEd also says the standard terms of each LTPPA define the "Product" to be curtailed to include both the energy and the associated REC:

> "Product" means Illinois or Adjoining State Wind, Illinois or Adjoining State PV, Illinois or Adjoining State Other RER, Other State Wind, Other State PV or Other State Other RER, as indicated in this Confirmation, and includes both the energy and the associated REC. Capacity is not

included in the Product and Seller retains all rights and benefits from the capacity associated with the Generating Unit.
(Id., emphasis added)

According to ComEd, the law is well-established that a court must construe the meaning of a contract by looking at the words used; it cannot interpret a contract in a way which is contrary to the plain and obvious meaning of those words. (ComEd Response at 4-5, citing J.M. Beals, Inc. v. Industrial Hard Chrome, Ltd., 194 Ill. App. 3d 744, 748 (1st Dist. 1990)) Nor can the court rewrite the clear terms of a contract to provide a better bargain to suit one of the parties. (Cress v. Rec. Servs., Inc., 341 Ill. App. 3d 149, 185 (2nd Dist. 2003)) ComEd argues that here, it is indisputable that the plain language of the contracts call for the LTPPAs Annual Contract Quantity of "Product," – that is, "both the energy and the associated REC" – to be "reduc[ed] proportionately" if the cost cap is exceeded. ComEd says the RS' proposal would require the Commission to unlawfully delete some words ("both the energy and"), and add others to the LTPPAs ("and includes only the associated REC"). (ComEd Response at 4-5)

ComEd states to the extent any party misreads the statute's statement that "unless otherwise directed by the Illinois Commerce Commission or statute" somehow permits the Commission to freely modify the material terms of the LTPPAs, such position is untenable with the letter of the law. ComEd asserts the statement "unless otherwise directed by the Illinois Commerce Commission or statute," establishes a contingency on how "Product" as a whole – e.g., energy and RECs is – to be reduced if the rate cap is triggered. ComEd says, for instance, in the event the rate cap was triggered, instead of pro-rationing the LTPPAs to reduce Product, the Commission could elect to reduce Product within the highest-priced contracts first. ComEd argues nowhere does the agreement authorize the Commission or legislature to redefine what constitutes "Product." ComEd insists the term "Product" is defined firmly and separately from the provisions regarding curtailment, affording no discretion in interpreting the components that comprise the "Product." Had the parties intended to turn the definition of Product into a moving target susceptible to modification, ComEd claims the contract would have stated as much. (ComEd Response at 5)

ComEd believes while the Commission need not look any further than the agreement to decide the issue, the Commission's decision in Docket No. 09-0373 confirms that the Product includes both RECs and energy. ComEd says in that same proceeding, the Commission also concluded, in its final Order, that "The IPA's proposal for the procurement process to be on a bundled basis, for both energy and the RECs generated from the project …will potentially benefit utility customers; the proposal should be approved for this Plan." (ComEd Response at 5-6)

ComEd argues while this is the process the RS and utilities are contractually and legally bound to, it makes sense for other reasons. In approving the LTPPAs four years ago, ComEd says both the IPA and the Commission recognized that over the course of these multi-decade contracts, the potential existed for the contract volumes to be greater than what could be supported by ComEd's retained load. As a result of high levels of customer switching between the 2009 docket and today, ComEd indicates this is precisely the issue with which we are confronted. ComEd claims had we the benefit of knowing in 2009 that ComEd's customer load would decline to current levels, then the parties would have simply contracted for lower quantities such that ComEd would not over-procure the amount of renewable energy that its customers could support. By requiring the RS to reduce both energy and RECs, ComEd says this is precisely what we achieve. (ComEd Response at 6)

According to ComEd, when considered in whole, the agreements demonstrate that the definition of Product can only be interpreted to include both energy and RECs. ComEd states in the event the Product must be curtailed, each Supplier is entitled to exercise the following remedies: (a) terminate the agreement, (b) permanently reduce the quantity of Product to the curtailed level, or (c) reduce the quantity of Product for that delivery year. ComEd claims no remedy contemplates any process that would allow the parties to treat Product as anything but energy and RECs. While the RS are understandably frustrated about not receiving the revenues they may have hoped, ComEd insists the contract language clearly spells out the options from which the renewable suppliers can choose if their contract is curtailed, none of which includes curtailing RECs only. (ComEd Response at 7)

ComEd also argues its customers have already paid a premium to the renewable suppliers to accept or manage this risk in the agreed-to fixed price contained in the LTPPAs. In ComEd's view, the contract terms should not be re-written now to require its customers to pay a second time for this risk. (Id.)

In the alternative, the renewable suppliers request that if the Commission declines to re-write the terms of the LTPPAs to their benefit, it should instead require "the electric utilities (using hourly ACP) and the IPA (using the RERF) [to] purchase curtailed RECs at a price equal to the bundled Contract Price less the day-ahead hourly LMPs." ComEd says in other words, if the Commission refuses to re-write the LTPPAs to increase supplier margins directly, the RS requests that the Commission order customers to subsidize them indirectly. ComEd argues this approach is inappropriate, unjust, and should be rejected. (ComEd Response at 7)

ComEd asserts the Commission has already determined that the appropriate price for purchasing curtailed RECs is equal to the imputed REC price. In Docket No. 09-0373, ComEd says the Commission approved the following language:

> The IPA intends to count the REC portion of the procurement toward the RPS requirements and bill-impact cap. To quantify the annual cost of the RECs for the purpose of the RPS, the Procurement Administrator, in consultation with the IPA, ICC Staff, and the Procurement Monitor shall develop a confidential 20 year forward price curve for energy at the load zone, including the estimated magnitude and timing of the price effects related to federal carbon controls. Each forward curve shall contain a

> specific value of the forecasted market price of electricity for each annual delivery year of the contract. In every delivery year, the imputed REC component of expenditures under the bundled renewable contracts will be determined as the difference between the expected annual contract expenditures for that year (based on the winning target Contract Quantities and Contract Prices) and the total target Contract Quantities times the forward price curve for each respective load zone for that year.
> (ComEd Response at 8)

ComEd says the price paid for curtailed RECs is approximately $18/REC compared to the current market price for spot RECs of approximately $1/REC, and in ComEd's view, is very generous. ComEd says the RS' recommendation to price curtailed RECs at the LTPPA prices, less the current market price, would increase the average price paid for RECs to roughly $25/REC, or almost 40% compared to the average imputed REC price. According to ComEd, while there is no legislation or contract provision that specifically addresses how to price a REC purchased with alternative compliance payment, ComEd believes it would seem logical that it should be either the current market price for RECs (~$1) or the imputed price of RECs in the contract (~$18). In addition, ComEd says the IPA has made clear it intends to use the imputed REC price to purchase curtailed RECs using the retail electric suppliers' ACP funds, which the IPA notes are outside of the Commission's purview. ComEd asks why then should ComEd hourly customer ACP funds be used to purchase curtailed RECs at a substantially higher price than those of customers supplied by retail electric suppliers. (ComEd Response at 8-9)

ComEd asserts while further increasing the price of curtailed RECs purchased with ComEd customer ACP funds would enable the LTPPA suppliers to be kept whole, ComEd's customers would clearly not benefit from this action. ComEd insists the Commission should reject the RS' request to increase the price ComEd hourly customers pay for RECs. (ComEd Response at 9)

In its Reply to Responses, ComEd notes that WOW states that it supports the RS' recommendations regarding the manner in which RECs are curtailed and the process for review and comment on the spring load forecasts. Consistent with and for the reasons in its Response, ComEd objects to all of these proposals. (ComEd Reply at 8-9)

According to ComEd, WOW also postulates that because ComEd's rate is now much closer to the prevailing market price, it is implausible that there will be additional customer migration from ComEd. ComEd disagrees. In addition to at least one known government entity pursuing a March 2014 municipal aggregation referendum, ComEd claims there are still several municipalities moving forward to implement aggregation programs previously approved by voters. ComEd says RES also continue to solicit individual customers to switch away from ComEd. While price is certainly an important factor in such a decision, ComEd believes it is not the only factor. ComEd states a number of communities and individuals select RES suppliers based on higher renewable content than the ComEd offering (such as 100% green programs). ComEd says it will take the latest information on these and other factors into account when it updates its forecast in March of 2014. In ComEd's view, the Commission should disregard WOW's recommendations. (ComEd Reply at 9)

7. Commission's Conclusions

The RS primary proposal with regard to renewable resources is that the IPA Plan be revised to state, and the Commission order, that only REC purchases under the LTPPAs, and not the energy portion of the LTPPAs, should be curtailed for the 2014-2015 procurement year. The RS recommends the Commission order that the energy component of the LTPPAs associated with the curtailed RECs not be curtailed, but rather should be settled by the electric utilities based on the energy price from the 2010 forward energy price curve less the day-ahead hourly LMP for each hour. WOW endorses RS' proposal.

The RS proposal is opposed by ComEd, AIC, and Staff. Among other things, those opposed to the RS proposal argue that it is in direct conflict with the terms of the LTPPA contracts and would adversely affect the eligible retail customers of ComEd and AIC. If the Commission finds Staff, AIC, and ComEd's arguments persuasive that the contract provides for curtailment of energy as well as RECs, the IPA strongly urges the Commission to require all parties to adhere to the terms of the contract. The RS refute the arguments of ComEd, AIC, and Staff. The RS argues that the LTPPAs were not the result of arms length negotiations and the Commission possesses the authority to "direct" a reduction of something "other" than "the quantity of Product purchased" so that the amount of expenditures are recoverable.

The RS also disputes arguments that its proposal would violate Section 16-111.5(e)(3) of the PUA because it would result in the utilities purchasing electricity at prices that have not been evaluated through benchmarks. The utilities also argue that its proposal for settling the energy portion of the LTPPAs associated with curtailed RECs will adversely impact their eligible retail customers because the eligible retail customers will have to pay the difference between the current market price of energy (the day-ahead LMPs) and the energy prices in the IPA's 2010 forward energy price curve. In response, the RS notes the current year energy price from the 2010 forward energy price curve is higher than the day-ahead LMPs and insists the payment of this amount is consistent with the terms of the LTPPAs and with the IPA's evaluation of the bid prices at the time of contract award using the 2010 forward energy price curve.

The RS suggests the Commission should unilaterally change the terms of the contract to favor one party over the other party to the contract. The question of whether the Commission has authority to do so is not a black and white one. On the one hand, the RS is correct that the LTPPAs were not the result of arms length negotiations. On the other hand, the LTPPAs were specifically developed to allow for the possibility of curtailments, and yet the definition of Product contained therein specifically included both the energy and REC component and that definition was accepted by both parties to the LTPPAs.

Putting aside the question of whether the Commission possesses authority to impose such a change to the LTPPA contracts, in this instance the Commission is disinclined to do so. In the current situation, such a change would favor the RS and would, ultimately, impose the cost on ComEd and AIC eligible retail customers. In addition, the Commission notes that such a change would modify the LTPPA contracts from the manner in which they were intentionally drafted to protect eligible retail customers. In this instance, the Commission concludes such a change is not in the public interest and will not be adopted. Finally, the Commission notes, despite the fact that the record in this proceeding is different than the one in Docket No. 12-0544, the Commission previously determined that the curtailment of LTPPAs should include both energy and REC. The Commission believes the record in this proceeding supports the same conclusion.

As an alternative to its primary proposal, the RS proposes for the IPA Plan to be revised to specify that the utilities (using hourly ACP funds) and the IPA (using RERF monies) will purchase curtailed RECs under the LTPPAs at a price equal to the LTPPA Contract Price less the day-ahead hourly LMPS for the energy associated with the curtailed RECs. This proposal is again supported by WOW.

The RS alternative proposal is opposed by ComEd, Staff, and AIC. The IPA states that the question of using hourly REC prices for curtailed RECs is outside the scope of this proceeding to the extent that it relates to payments made from the RERF.

AIC says the RS' alternative proposal appears to be in violation of the statute which requires a process of benchmarking, request for proposals, sealed bidding and selection of winners based on price. Staff asserts the RS' alternative proposal to use highly variable and uncertain REC spot prices for settlement purposes would leave ratepayers exposed to considerable risk, if spot prices were to fall and would almost surely result in payments for RECs that exceed those under the IPA’s pricing proposal.

ComEd argues the Commission already decided in Docket No. 09-0373 that the appropriate price for purchasing curtailed RECs is equal to the imputed REC price. ComEd also asserts that further increasing the price of curtailed RECs purchased with ComEd customer ACP funds would enable the LTPPA suppliers to be kept whole, but its eligible retail customers would not benefit from this action. The RS believes, contrary to ComEd’s argument, its alternative proposal would not result in any increased charges to the utilities’ retail customers. The RS also argues the current situation creates a disincentive to the development and construction of new renewable resource generating facilities in Illinois.

Currently, the LTPPA suppliers are operating under the LTPPA contracts to which they agreed and are reimbursed in the manner the Commission has deemed appropriate. It appears to the Commission that the only basis for the RS' alternative proposal is to produce current economic benefits to the LTPPA suppliers at costs paid by ComEd's and AIC's eligible retail customers. While the Commission fully understands the RS incentives, it is not clear how or why shifting costs from the suppliers to the utilities' customers is fair or in the public interest. Should the RS provide the Commission with sufficient evidence to prove this proposal would not harm utility customers and would be in the public interest, the Commission may be inclined to revisit the issue. The Commission notes that pricing for curtailed RECs was previously addressed in Docket No. 09-0373 and finds there is not a sufficient basis for altering that decision based on the record in this proceeding.

With regard to the RS argument regarding the incentives to construct new renewable resource facilities in Illinois, the Commission notes that there are competing objectives relating to renewable resources and balancing those competing interests is a difficult task. The Commission declines to adopt the RS alternative proposal in this proceeding as it is not in the public interest.

E. Load Forecasts

1. Renewable Suppliers' Position

The RS notes the IPA Plan recommends that the electric utilities “base” or “expected” load forecasts for 2014-2015 be adopted for purposes of the 2014 Procurement Plan. According to the RS, the values of the projected eligible retail customer load in the ComEd “expected” load forecast for the 2014-2015 procurement year are not the midpoint values between the values in the ComEd “high” and “low” load forecasts, but rather are closer to the forecast values in the “low” load forecast. The RS says the projected energy usage of ComEd eligible retail customers for the 2014-2015 procurement year under ComEd’s high, base/expected, and low load forecasts is:

High forecast	16,380,846 MWh
Base/expected forecast	11,131,421 MWh
Low forecast	9,465,530 MWh

The RS says the midpoint energy usage value between the high load forecast and the low load forecast is 12,923,188 MWh, which is 1,791,767 MWh (16.1%) higher than ComEd’s “expected” load forecast for the 2014-2015 Procurement Year. (RS Objections at 15)

The RS says for AIC, the values of the projected eligible retail customer load in the AIC base/expected load forecast for the 2014-2015 procurement year are not the midpoint between the forecast values in the AIC “high” and “low” load forecasts, but rather are closer to the forecast values in the “low” load forecast:

High forecast	10,702,018 MWh
Base/expected forecast	4,965,273 MWh
Low forecast	1,869,670 MWh

The midpoint energy usage value between the high load forecast and the low load forecast is 6,285,844 MWh, which is 1,320,571 MWh (26.6%) higher than AIC's middle load forecast for the 2014-2015 procurement year. (RS Objections at 15-16)

In the RS' view, the IPA Plan makes it clear that customer switching is the major source of uncertainty in the utility load forecasts. The RS notes switching by eligible retail customers due to municipal aggregation programs, wholesale pricing and market arrangements highlights that switching by eligible retail customers is by far the major uncertainty factor associated with near-term load forecasts. The RS says other factors discussed, including the impacts of weather, energy efficiency programs, demand response programs, and emerging technologies (such as advanced metering infrastructure and electric vehicles), do not appear to be significant drivers of load forecast uncertainty for the 2014-2015 procurement year. (RS Objections at 16)

The RS states despite the IPA's analysis of possible load uncertainty, the IPA Plan recommends adoption of a ComEd base or expected load forecast that reflects a projection by ComEd that the share of the eligible retail customer load it will supply will decrease from 34.4% in June 2013 to 28.1% in June 2014 and further to 25.1% in June 2015. Similarly, the IPA Plan recommends adoption of an AIC base load forecast which projects that the share of residential load in AIC territory supplied by ARES will increase from approximately 55% as of June 1, 2013 (Appendix B at 8) to approximately 68% in June, 2014 and approximately 70% by April 2015. The RS says despite the IPA's recognition that the greatest source of uncertainty in the utility load forecasts is the extent of customer switching, and in particular the risk of significant re-migration of eligible retail customer load back to the utilities, it is not apparent from the discussion in the IPA Plan why assumptions about customer switching in 2014-2015 should result in the forecast values in the utilities' "expected" load forecasts being closer to the low load forecast values, rather than midpoint values between the "high" and "low" forecast values. (RS Objections at 16-18)

The RS believes the discussion in the IPA Plan does not support the additional amounts of eligible retail customer switching from the electric utilities to ARES reflected in the utilities' "expected" load forecasts for the 2014-2015 procurement year, nor the adoption for purposes of the IPA Plan of forecasts that incorporate these customer switching assumptions. In the RS view, the IPA and the Commission need to place greater emphasis than is reflected in the "expected" load forecasts on the risk of significant re-migration by eligible retail customers from ARES to the electric utilities during the 2014-2015 procurement year. Given the extent of migration to ARES due to municipal aggregation programs that have been adopted over the last two years, the state of these programs, the lack of significant additional municipal aggregation referenda, the expiration of municipal aggregation contracts with ARES and the expiration of higher-priced legacy utility supply contracts, and potential price trends and customer reactions to them the RS insists there is a much greater risk that a significant segment of eligible retail customers will return to the utilities from the ARES, than there is that significantly more eligible retail customers will switch from the utilities to the ARES. According to the RS, the IPA Plan's proposed adoption of the utilities "expected" load forecasts fails to comprehend this risk. The RS asserts that if there were to be significant re-migration of eligible retail customers to the electric utilities, the contracted supplies could be inadequate, resulting in a need for the utilities to acquire additional supply during 2014-2015 in spot markets or through other shorter-term and higher-priced arrangements. The RS believes this outcome would be detrimental to ratepayers. (RS Objections at 18-19)

The RS says it does not have access to the detailed mathematical models and calculations used by the electric utilities in order to "redo" the utility forecasts. However, the RS suggests one way for the Commission to better address the significant risk of re-migration of eligible retail customer load to the utilities is to direct that the IPA Plan adopt load forecast values for the 2014-2015 procurement year that are at the midpoint values between the electric utilities' high and low load forecasts. The RS believes adoption of load forecast values that are midpoint values between the utilities' high and low load forecasts would more appropriately recognize that the most significant risk associated with the 2014-2015 procurement year is the risk of substantial re-migration of eligible retail customer load to the electric utilities. (RS Objections at 19-20)

The IPA Plan contemplates that the electric utilities will submit load forecast updates in Spring 2014 and that these load forecast updates, if accepted by consensus of the IPA, Staff, the Procurement Administrator(s) and the Procurement Monitor, will be the final load forecast values used to determine the electric utilities' supply requirements for the 2014-2015 procurement year, whether the RRB will be exceeded, and whether and to what extent curtailments of REC purchases under the LTPPAs will be required. The RS says the Spring 2014 load forecast values (if accepted) will determine whether and to what extent (if any) the RRBs for the electric utilities will be exceeded and, if so, the extent of the curtailment of REC purchases under the LTPPAs. Therefore, the Spring 2014 load forecast updates are extremely important to the renewables suppliers and may lead to serious adverse financial impacts for them. Given the importance of the Spring 2014 load forecasts, the RS believes interested parties should be afforded a brief period to review and submit comments on the updated load forecasts before they are adopted (or adopted with adjustments). The RS believes that for the Commission to subject the renewables suppliers and the other holders of LTPPAs to curtailments of deliveries and to reduced payments under their contracts based on load forecasts on which the suppliers are given no opportunity to comment would be problematic. The RS also says the updated load forecasts should be approved or adopted by a supplemental order of the Commission in this docket, not through discussions among the utilities, the IPA and Staff. (RS Objections at 20)

The RS recommends that the Commission, in its order in this docket, provide that: (1) the utilities should file their Spring 2014 load forecast updates with the Commission in this docket; (2) there should be a brief period (7 to 14 days) after the

Spring 2014 load forecasts are filed during which interested parties can submit comments on the updated load forecasts; and (3) the Commission should then issue a supplemental order in this docket either adopting the updated load forecasts, adopting the updated load forecasts with adjustments, or rejecting the updated load forecasts and directing that the load forecasts adopted in the Commission's December 2013 order in this docket be used for purposes of the 2014 Procurement Plan, including the final determinations of whether the RPS rate impact limits are exceeded and curtailments of REC purchases under the LTPPAs are needed for either electric utility. (RS Objections at 20-21)

The IPA, Staff and ComEd argue that in previous procurement plan cases, the Commission has consistently (i) adopted the utilities' base or middle load forecasts, and (ii) provided for the Spring load forecast updates to be adopted (or not) by consensus of the IPA, Staff, the Procurement Monitor and the Procurement Administrator, without allowing an opportunity for other interested parties to provide input nor requiring a Commission order. The RS notes that the Commission's past decisions are not *res judicata*, and that the Commission can reach a new or different result in a future case even when faced with the same or a similar situation or set of facts. The RS believes there is good reason to depart in this case from the approach adopted in prior cases: the large number of municipal aggregation supply contracts which will be coming up for renewal during 2014 and for which the ARES' renewal supply contracts may no longer be price-competitive with the utilities' supply service prices, creates a substantial risk of a significant change in the load forecasts between now and Spring 2014. The RS says the Spring 2014 load forecasts are of much greater importance than in prior cases to the interests of the RS and other suppliers, all of whom may have useful market intelligence and perspectives on the factors impacting, and the extent of, customer switching. The RS believes comment on the Spring 2014 load forecasts should be allowed, and they should be adopted, adjusted or rejected by the Commission in an order. (RS Reply at 15-16)

Staff and AIC state that the RS should not be allowed to comment on the Spring load forecasts because they have a financial interest in what the forecasts are, whereas the IPA, Staff, and the Procurement Administrator and the Procurement Monitor are disinterested entities. The RS argues the fact that its has a financial interest in the final load forecasts is precisely why they should be given the opportunity to comment on the Spring load forecasts. The RS believes it would be unreasonable to subject the RS to curtailments of its LTPPAs and the resultant revenue loss and financial harm based on load forecasts on which they were given no opportunity to comment and which are "adopted" not by a Commission order, but by "consensus" of a group to which the Commission delegates its authority. (RS Reply at 16)

The IPA and ComEd argue that there is no need for a comment period for the Spring 2014 load forecast updates because any issues associated with the utilities' load forecast methodologies can be thoroughly vetted and litigated in this proceeding, and the Spring 2014 load forecasts will just involve application of the approved methodologies to updated data. The RS asserts that to think that this proceeding provides the opportunity to thoroughly litigate issues relating to the utilities' load forecast methodologies is unrealistic. The RS notes that per Section 16-111.5 of the PUA, the entire duration of the proceeding is only 90 days, and parties are given only five business days after the proposed Plan is filed with the Commission to prepare and submit objections. Thereafter, the RS says the parties were given only 14 days to file responses to the objections and 10 days to file replies to the responses. The RS says there is no discovery, no testimony and no hearings. Even taking into account that Section 16-111.5(d)(2) requires the IPA to post a draft plan for comments for 30 days before filing its plan with the Commission, the RS argues there is not a meaningful opportunity to investigate and litigate the utilities' load forecast methodologies. The IPA also suggests that if the RS are concerned about the risk of re-migration, it should present an alternative methodology for assessing that risk and predicting the amount of load that may return to utility supply service. According to the RS, the nature and tight time frames for this proceeding do not provide a reasonable opportunity to develop and present a new methodology. (RS Reply at 16-17)

The RS says it is not actually taking issue with the methodologies used by the utilities to develop their long-term, structural base load forecasts – e.g., how the utilities' forecasting methodologies and approaches take into account such structural drivers of electricity demand as population and household growth in the service area, economic activity, income changes, and responses to weather patterns. The RS says it is not taking issue with the utilities' forecasts of overall electricity demand in their service areas, or with their forecasts of overall electricity demand from eligible retail customers in their service areas. The RS says the load forecast drivers that specifically concern the RS are the assumptions concerning the extent of customer switching by eligible retail customers between ARES supply and utility supply service during the procurement year – that is, how the total load of residential and small commercial customers will be divided between the utilities and the ARES. The RS asserts this part of the forecast is not dependent on formulas or methodologies – i.e., on plugging projected values of inputs into a mathematical equation or computer model that produces a result – but rather on specific, current, program-by-program information on the status of municipal aggregation programs, which ones are up for renewal, which ones have been or may be terminated, and the comparative pricing between the ARES supply contracts for municipal aggregation programs and the utilities' prices for eligible retail customers electric supply service. The RS contends, this particular issue is not one of competing "methodologies," at least not at this time and with the very limited histories associated with the municipal aggregation programs. (RS Reply at 17-18)

The RS asserts the continuously emerging information on the factors driving customer switching and re-migration may cause the customer switching assumptions, and thus the overall load forecasts, to change materially from the time of the utilities' July 2013 forecast submissions to the IPA to the time of their Spring 2014 load forecasts. The RS says neither the utilities, nor the IPA, Staff and the Procurement Administrator and Procurement Monitor, have a monopoly on relevant market information. The RS asserts other parties, including it, will also have relevant market intelligence, and should be allowed to comment on the utilities' Spring 2014 load forecasts. The RS notes AIC states that it has recently learned that the primary consultant in its service territory is working with municipals and ARES in order to pursue the renewal of a majority of municipal aggregation contracts that were scheduled to expire in summer 2014. According to the RS, this observation does not bespeak a “methodology” to forecast the amount of customer switching or re-migration, but rather the application of the most current market and pricing information to project these values. The RS claims AIC’s comment only indicates an intent by the unnamed consultant to pursue the renewal of a majority of expiring contracts – it will be the results that count, which will be manifesting over the next six months. The RS says even if a majority of municipal aggregation contracts are renewed, if the new prices are not competitive with the pricing of utility supply service, significant numbers of individual eligible retail customers may re-migrate from the municipal aggregation programs back to utility supply service. (RS Reply at 18-19)

The IPA states that the RS' recommendation to adopt load forecast values that are the midpoint between the utilities’ “high” and “low” forecast values would be averaging two forecasts that are not intended to be averaged. The RS says the underlying objective of this proposal is to give greater (and adequate) recognition to the risk of re-migration. The RS believes the IPA Plan itself highlights the serious risk of re-migration to utility supply service and the consequent risk to ratepayers; yet the base load forecasts the IPA Plan adopts are not consistent with the IPA’s own discussion of the likelihood of significant re-migration. The RS claims the IPA and the other parties have not refuted this discussion. The RS notes even in its Response, the IPA states that it is not clear exactly how customers eligible for bundled service will act if the bundled prices diverge from market prices. The RS believes its proposal to use the average of the “high” and “low” forecast values provides a simple, straightforward way (consistent with the limited time for this proceeding) to give greater recognition to the risk of re-migration without “re-doing” the load forecasts. (RS Reply at 19-20)

The RS' concern is that the utilities’ “base” load forecasts do not adequately take into account the significant risk of re-migration – in fact, the base load forecasts actually incorporate assumptions of increased customer switching to ARES in the 2014-2015 procurement year – and the RS believes that the Commission should direct the adoption of load forecast values, or make adjustments to the utilities’ base load forecasts, in order to better take account of this risk. The RS says its proposal that the Spring 2014 load forecasts be filed with the Commission, that comments on them be allowed, and that the Commission issue an order adopting, adopting with adjustments, or rejecting, the Spring 2014 load forecasts, allows the Commission to apply its judgment, based on the record of information supplied by the utilities and other interested parties, as to what amounts of customer switching and re-migration should be projected for the 2014-2015 procurement year. (RS Reply at 20)

Staff argues that the RS' proposal may conflict with Section 16-111.5(d)(3) of the PUA which specifies that the Commission is to issue a final order within 90 days after the IPA files its proposed Plan. The RS believes Staff’s argument elevates form over substance – as Staff would have it, the Commission must issue a “final” order by

December 30, 2013, but the most important component of the IPA Plan would then get adopted by a committee of the IPA Staff, the Procurement Administrator and the Procurement Monitor, without a Commission order even to ratify their decision. The RS also believes the concept that Section 16-111.5(d)(3) is satisfied by "pre-approving," in the December 2013 order, a load forecast that has not even been filed yet, is spurious. (RS Reply at 20)

The RS asserts there are procedural solutions available to Staff's concern. The RS suggests the Commission can issue a final order by December 30, 2013, but can then reopen the proceeding for the purpose of receiving the filing of the Spring 2014 load forecast and comments thereon and issuing a supplemental order adopting, adopting with adjustments, or rejecting the Spring 2014 load forecasts. The RS suggests in the alternative the Commission can grant requests for rehearing for the purpose of reconsidering the approved load forecasts, and in the course of the rehearing proceeding, which the Commission will have 150 days to conduct, the Spring 2014 load forecasts can be filed and commented on, and the final load forecast adopted in the order on rehearing. (RS Reply at 20-21)

2. AIC's Position

AIC notes that the Plan also proposes that the July 2014 forecast required of AIC in the next plan (which will cover the period June 2015 through May 2020) should include an update of the period November 2014 through May 2015, which represents a portion of the prompt year associated with this plan. The IPA desires to use the updated forecast for November 2014 through May 2015 in determining whether a September 2014 energy procurement (second procurement for the prompt year) should be pursued and for determining the associated quantities, if any. AIC says the Plan is clear that the November 2014 through May 2015 forecast update would have no bearing on the curtailment quantities under the long-term renewable contracts. While AIC agrees with this proposal, the Plan should be clear that it is seeking Commission pre-approval of the November 2014 through May 2015 updated forecast in this plan and through consensus of the aforementioned parties in July 2014. AIC also believes the forecast update for November 2014 through May 2015 should be submitted to the IPA independent of the five year forecast (June 2015 through May 2020) associated with the next plan. AIC says since the November 2014 through May 2015 forecast update is pre-approved in this plan, it will not become part of the docketed proceeding in the next plan. AIC believes the language as currently proposed in the Plan could lead to confusion and hence recommends these clarifications. (AIC Objections at 3-4)

According to AIC, the RS recommends the Commission should direct the March 2014 load forecast updates be filed with the Commission in this docket with a brief period for interested parties to file comments on the updated load forecasts, followed by a supplemental Commission order that adopts the load forecast updates, adopts them with adjustments, or rejects them in favor of using the forecasts approved in the Commission's December 2013 order. AIC says WOW makes a similar recommendation asking that the load forecasts provided by AIC in March 2014 be made publically available. AIC disagrees with these recommendations and continues to support the IPA proposal that AIC provide an updated March 2014 forecast which will be pre-approved by the Commission in this docket subject to the March 2014 consensus of the IPA, Commission Staff, Procurement Administrator, Procurement Monitor and the utilities. If consensus is not reached, the IPA proposes that the July 2013 forecast be used. (AIC Response at 3-4)

AIC objects to the inclusion of the RS and WOW in the review of the March 2014 forecast since they have a financial incentive in achieving higher forecasts which in turn would reduce the quantity of the proportional curtailment associated with the long-term renewable contracts. AIC asserts this is in contrast to the other parties the IPA has proposed be involved in the March 2014 review process who have no financial incentive to make the forecast higher or lower and therefore will remain objective during the review process. In addition, AIC says the IPA proposal has been approved by the Commission in past plans and has ensured the forecast updates represent the best available approximation of forward looking load without the influence of undue bias. For these reasons, AIC recommends the Commission reject the RS and WOW proposals regarding a comment period associated with the March 2014 forecast update and a supplemental order by the Commission. Instead, AIC recommends the Commission approve the IPA proposal. (AIC Response at 4, Reply at 2-3)

AIC notes the RS states that the load forecasts adopted by the IPA Plan do not adequately take into account the significant risk of re-migration of eligible retail customers from ARES to the utilities. Further, the RS proposes that the IPA Plan use a midpoint value between each utility's high and low load forecast.

AIC also notes that the statute requires the utilities to provide expected, high and low forecasts to the IPA. In past plans, AIC says the expected forecast has formed the basis for the procurement quantities proposed by the IPA and ultimately solicited by the IPA after Commission approval. AIC indicates the high and low forecasts were used in determining whether rebalancing events were required or in the assessment of risk surrounding the expected forecast scenario. By contrast, AIC says the RS is proposing a forecast that is not defined or required under the statute. AIC asserts the RS has a financial incentive to make the forecasts as high as possible, which in turn would reduce the quantity of curtailments under the LTPPAs and ultimately benefit renewables suppliers at the expense of eligible retail customers. AIC claims it has recently learned that the primary consultant in its service territory is working with municipals and ARES in order to pursue the renewal of a majority of municipal aggregation contracts that were scheduled to expire in summer 2014. While AIC made this assumption in the expected forecast scenario provided to the IPA in July 2013, the high forecast scenario assumed the majority of these customers would return to eligible retail load. Assuming AIC receives confirmation that aggregation contracts have been extended beyond 2014 for the aforementioned municipals, AIC indicates it will modify its high forecast scenario during the March 2014 forecast update. At least in the near term, AIC claims this development makes moot the comments of the RS regarding the significant risk of re-migration of eligible retail load. (AIC Response at 8-9, Reply at 4)

3. WOW's Position

WOW recommends that the load forecasts provided by the utilities in Spring 2014 be made publicly available. WOW notes the IPA recommends that no additional renewable energy resources be procured at this time for ComEd or AIC during the planning horizon because both utilities' "Contractual REC Cost" will exceed the RPS Budget for each of the next five delivery years. The IPA also recommends that the Spring 2014 updates to both utilities' load forecasts be used to confirm the amount of curtailment of renewable energy resource contracts for the 2014-2015 delivery year, however, WOW says the Plan is silent as to whether those forecasts are to be made publicly available. (WOW Objections at 2)

WOW recommends that the utilities' Spring load forecasts be made available since the July and November forecasts are publically available. WOW says if contracts are to be curtailed it will be based on the Spring load forecasts and parties who are in this case or subject to the curtailment may want to challenge aspects of the Spring load forecasts, such as their validity or accuracy, to the extent the methodology and data in the Spring load forecasts varies from the July load forecasts. (WOW Objections at 2, Reply at 2) WOW says AIC has asked that load forecast updates provided by the utilities in November 2013, March 2014 and July 2014 be approved in this plan. In WOW's view, if they are approved, then those load forecasts should be made public within this docket and posted to the Commission website. WOW maintains there is no reason to keep those plans confidential. (WOW Reply at 2)

WOW says AIC supports the IPAs proposals that an updated March 2014 forecast be pre-approved by the Commission subject to the consensus of the IPA, Staff, Procurement Administrator, Procurement Monitor and utilities. WOW states its position that load forecasts be made public and posted to e-docket is <u>not</u> a comment in support of the Commission pre-approving the March 2014 or July 2014 forecast updates, or support for the methodology the utilities have used in performing their load forecasts prior to those forecasts being made public and reviewed by stakeholders. (WOW Reply at 2)

WOW notes that in previous years, ComEd has filed its November load forecast in the docket. WOW suggests the utilities could do the same with their Spring load forecasts. (WOW Objections at 2) WOW notes Staff volunteers to post the updates on the Commission website. WOW accepts Staff's offer; however, WOW believes the data should also be filed on e-docket since the utilities file their November forecasts and post them on e-docket. WOW says if the data is part of the Commission order -- either approved by Staff and others during their review in March or is pre-approved by the Commission in December -- that information should be posted on e-docket but not necessarily made part of the record since it will have been closed by that time. (WOW Reply at 2-3)

WOW notes the RS proposes a process for it and other stakeholders to review and comment on the Spring load forecasts that are to be used to determine the level of curtailment of contracts the renewable suppliers are party to. WOW supports this objections and the RS proposed resolution. (WOW Response at 5-6)

WOW complains that neither utility provides much discussion around the prospect of load returning to the utilities or support for load migration to the ARES continuing. WOW suggests it is possible that load migration from the utilities in the 2014-2015 period will be zero or negative (meaning load could return from municipalities and local governments whose aggregation contracts end in the 2014-2015 period) given the current rate offerings and the likelihood for rates changing on a going forward basis. (WOW Response at 6)

Using data from the Commission's website, WOW claims the current average rate offered by ARES to local governments in the ComEd territory is 5.08 ¢/kWh which is greater than ComEd's current offering of 4.625 ¢/kWh Summer rate and 4.586 ¢/kWh non-Summer rate. WOW says the average ARES rate for local government contracts in the AIC territory are comparable to AIC's Summer and non-Summer rates; being higher than the Summer rate but lower than the non-Summer rate. (WOW Response at 6)

WOW claims the Energy Information Agency ("EIA") does not project electricity rates to change much over the next 10 years, so the opportunity for a significant rate difference between utility rates and ARES' rates is small. In WOW's view, there is little likelihood that in the near future that ARES will be offering rates that are significantly lower than the utilities' rates such that a municipality would be enticed to aggregate its load and leave their default supplier. WOW believes the utilities' Base load forecasts should reflect no changes due to load migration or in the alternative should reflect a migration of load from the ARES to the utilities as proposed by the RS. WOW claims load migration from utilities in the 2014-2015 period is likely to be zero or negative given the current rate offerings and the likelihood for rates changing on a forward-going basis. (WOW Response at 6-7)

4. The IPA's Position

The IPA states although the utilities' load forecasts are not primarily a renewable energy issue, the load forecasts – particularly Spring updates – have become a litigated issue beginning with last year's Procurement Plan due in large part to the fact that utilities may curtail RECs received from their 2010 LTPPAs with certain renewable facility developers. The IPA says although curtailment of LTPPA contract quantities is a very real consequence of Spring load forecasts, the IPA views the load forecast primarily as a neutral assessment of how much supply the IPA must buy (if any) during Spring procurements. The IPA says it is guided in part by the Commission's Final Order in the 2013 Procurement Plan, where the Commission explained that:

> While the Commission recognizes and appreciates other parties' desire to comment on the March 2013 load forecasts and curtailment volumes, the

> Commission sees no compelling reason to depart from its established load forecast approval process. Between the IPA, Staff, and ComEd/AIC (as well as the Procurement Administrator and Monitor, should they be retained), the Commission believes that technical issues related to load forecasting will be objectively vetted and appropriately addressed, just as they have been in past forecast approvals and in this docket.

(IPA Response at 8-9, citing Docket No. 12-0544, Order at 68)

The IPA believes that the Commission's discussion directed parties to litigate the methodology of load forecasts during the Procurement Plan docket. The IPA further believes that litigating methodology during the Procurement Plan docket provides the Commission with the best data to make all approvals related to procurement that could be significantly affected by changes in the load forecast. (IPA Response at 9)

Because the IPA believes that methodology should be litigated and decided up front, the IPA does not believe there is any need for a comment period following utility completion of the Spring, 2014 load forecast. The IPA says the RS recommended that the present docket remain open so that interested parties may comment on (and the Commission may presumably modify based on comments) the utilities' Spring 2014 load forecasts. The IPA recommends that the Commission reject that approach, in favor of litigating any issues with load forecast methodology during the case-in-chief in this docket. The IPA says, as detailed in the Draft Procurement Plan, the IPA along with Staff, the Procurement Monitor, and the Procurement Administrator will review the updated load forecasts to ensure that the utilities follow the methodology directed by the Commission if the Commission orders any modifications. (IPA Response at 9)

The IPA notes only the RS presented a methodological challenge to the load forecast. The RS make two points: first, that AIC and ComEd load forecasts are flawed because the "expected case" is not the midpoint between the high and low forecasts. The IPA says their second, related point is that the expected case is flawed because it should anticipate greater return of load to the utility. The IPA recommends that the Commission reject the first contention, and consider the second contention only to the extent that the RS can develop an alternative methodology to better capture return of load. (IPA Response at 9-10)

In the IPA's view, the midpoint argument should be rejected because it artificially creates an average of values that were not meant to be averaged. The IPA says the utilities develop their base case forecast first; the high and load cases are then excursion cases where variables and assumptions are changed from the base case based upon informed modeling. The IPA claims they are inherently not meant to be symmetrical, which is why the base case is not the midpoint between the high and low forecasts. The IPA contends the rationale behind any changes to the base, high, or low forecast should be based on the specific inputs to that specific forecast, not simple averaging. (IPA Response at 10)

With regard to load return to the utility, the IPA says both AIC and ComEd detailed the bases for their customer switching predictions and provided substantial justification for each one. However, as the IPA noted in the Draft Procurement Plan, it is not clear exactly how customers eligible for bundled service will act if the bundled prices diverge from market prices. The IPA believes any analysis that attempts to quantify this effect should be given due consideration, there is no basis for the contention that averaging the high and low load forecasts will be a better representation of consumer behavior. Unless and until a more rigorous method of quantifying load return or departure is presented, the IPA believes the utilities' approaches should be followed. (Id.)

ComEd recommended clarification of the parties involved in approving the Spring 2014 load forecast; the IPA believes this is a reasonable clarification and recommends the Commission approve the change. (IPA Response at 10-11, citing ComEd Objections at 8-9) WOW recommends that the updates to the Spring 2014 load forecasts be released publicly, perhaps by filing on e-Docket. The IPA agrees that the load forecasts are not confidential and thus are appropriate for public consumption, and does not object to using a filing in the present docket as a way to publicize the results. (Id.)

The IPA notes AIC requests that the Plan be updated to make it clear that the IPA is seeking in this plan Commission pre-approval of the November 2014 through May 2015 load forecast update that will be provided in July 2014. (IPA Response at 21, citing AIC Objections at 3-4) The IPA agrees with this request.

Based on the Responses to Objections, particularly from Staff, AIC, and ComEd, the IPA continues to recommend that the Commission reject the RS' recommendations. Staff, AIC, and ComEd all agreed with the IPA that neither of the RS' suggestions should be adopted, and provided substantial explanations of the technical, policy, and legal problems with adapting the RS' positions. (IPA Reply at 6)

The IPA notes Staff, AIC, and ComEd all objected to the RS' proposal regarding a comment period after the utilities release their Spring 2014 load forecasts as unjustified departures from the established processes (and legal requirements) for load forecasts. The IPA agrees with Staff's analysis about the RS' proposed March load forecast comment period, and urges the Commission to reject the proposal. (IPA Reply at 6-7)

The IPA says the comments of ComEd and AIC further support the IPA argument that high and low cases are then excursion cases where variables and assumptions are changed from the base case based upon informed modeling. In the IPA's view, using the high and low cases to create a base case would be inappropriate because the RS have not explained why an average of the high and low extremes better models risk to ratepayers. The IPA asserts ratepayer risk - not the risk facing parties engaged in arms-length transactions through the procurement process - should be the ultimate concern of the Commission. As a result, the IPA urges the Commission to reject the RS' recommendation that the high and low load forecast be averaged to set the expected load. (IPA Reply at 7-8)

5. Staff's Position

Staff opposes the RS' recommendation. Staff says while there is a risk of ARES customers returning to bundled service, the negative impact of being under-hedged is potentially smaller than the risk of being over-hedged. In this regard, Staff echoes the concerns expressed by AIC. (Staff Response at 14-15)

Staff also believes the Commission should reject the RS' proposal to keep this docket open for the purpose of receiving and arguing over the spring forecast updates. Staff says for a number of years, the Commission has had a process in place which deals with updated utility load forecasts that has worked well and can continue to work well in the future. Staff also asserts the proposal that additional filings take place in the current pending docket followed up by a supplemental order would be contrary to the requirements of the PUA. (Staff Response at 15)

Staff states in Docket No. 08-0519, the first proceeding involving the approval of an IPA Procurement Plan, the 2009 IPA Plan, the Commission addressed the issue of updated load forecasts to address the issue of load rebalancing. In that docket, the Commission stated the following:

> Thus, upon receipt of each such notification and updated forecast, the IPA shall utilize the process described on pages 39 and 52 of the Plan. Among other things, this process calls for the IPA to "convene a meeting with [the utility], the Commission and the Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved"

(Staff Response at 15-17)

In the following year's docket, Docket No. 09-0373, Staff says the Commission addressed the issue a second time. In that docket, the Commission stated the following:

> Among other things, this process calls for the IPA to "convene a meeting with [the utility], the Commission and the Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved"

(Staff Response at 17-19)

Staff notes the Commission has addressed this issue of load updates before, and a process for addressing it has been approved by the Commission and in place since 2009. Staff believes the IPA's 2014 Plan appropriately contains the same process approved in Docket No. 08-0519 and Docket No. 09-0373 (i.e., that process being the spring 2014 load forecasts will be subject to review by each utility, the IPA, Staff, the Procurement Administrator(s) and Procurement Monitor). Staff says this process will allow updated load forecasts and their impact on renewable curtailments to be taken into account by the IPA. Staff claims this process which appropriately only involves the disinterested parties of the utility, the IPA, Staff, the Procurement Administrator(s) and Procurement Monitor has historically worked well, and there is no reason to believe it should not continue to work well in the future. Staff believes the Commission should continue to use this long-established Commission approved process for addressing the spring 2014 load updates. In Staff's view, the RS proposal should be rejected. (Staff Response at 19-20)

Staff argues the RS proposal also should be rejected because, as proposed, it would conflict with the requirements of the PUA. Staff notes the RS' proposal keeps the record open in this proceeding to allow for the filing of comments by the RS and others and for the Commission to issue a Supplemental Order in the spring of 2014. Staff argues such a schedule would be contrary to the provisions of Section 16-111.5(d)(3) of the PUA that require the Commission to issue a final order within 90 days from the filing of the IPA's Plan, which, in this case, is December 30, 2013. (Staff Response at 20)

WOW recommends that the March 2014 forecast updates should be made public. Staff has no objection to this proposal. Staff also volunteers to post the updates on the Commission website. Staff says while it does not appear that WOW is echoing the RS' proposal to keep this docket open for the purpose of determining the March forecast updates, Staff reiterates its opposition to that proposal. (Staff Response at 20)

Staff supports AIC's encouragement of greater discussion of the risk of a dramatic price increase to eligible retail customers where hedges are in excess of requirements due to customer switching to ARES. Staff believes that AIC's use of the phrase "exponentially increasing costs" is not mere hyperbole. Staff asserts for any given deviation between a "locked-in" forward price ("FP") and a subsequent spot price ("SP"), the retail rates required to distribute or recoup the resulting gains or losses are extremely sensitive to the level of retained load. (Staff Response at 21-22)

Staff supports AIC's various recommendations concerning the spring forecast updates and revisions to the content of next July's forecasts. (Staff Response at 22-23)

6. ComEd's Position

ComEd notes that in its Objections, the RS propose that the Commission reject the Plan's use of the base forecast submitted by ComEd, and instead use an average of the High and Low cases. ComEd says while this would increase the RS' revenues by reducing REC curtailments, it is both unjustified and would unreasonably increase the risk and expense shouldered by ComEd's fixed price customers. (ComEd Response at 9)

According to ComEd, historically, the IPA has relied on and the Commission has approved ComEd's base case forecast to anticipate and reflect expected load and, in ComEd's view, for good reason. ComEd says as the Commission recognized in its Order in Docket No. 12-0544, "both AIC and ComEd have extensive experience and expertise in the area of load forecasting." ComEd asserts the base case is carefully constructed utilizing historical and prospective market and weather data, with the high and low scenarios designed to reflect more extreme weather, economic, and switching scenarios. For example, ComEd says the high scenario includes weather conditions reflective of one of the hottest summers in the past 20-plus years. Conversely, ComEd says the low scenario reflects weather conditions reflective of one of the coolest summers over the past few decades. Although not appropriate for anticipating actual load, ComEd claims the high and low forecasts are valuable for testing the IPA portfolio under those combined conditions. (ComEd Response at 9-10)

ComEd states if, as expected, ComEd's load were 11,000,000 MWh, but the Commission instead were to use a mean 13,000,000 MWh forecast to curtail the LTPPAs as proposed by the RS, then ComEd would have over-procured RECs for its customers, thus effectively exceeding the customer protection cost cap in the IPA Act. ComEd also asserts that under such scenario, ComEd – for its customers – would be forced to buy 2,000,000 MWh of additional energy because there is not a separate REC and energy forecast. ComEd claims the risk of such purchase would unjustifiably fall on customers: if ComEd were required to buy 2,000,000 MWh of excess power and the price of power were to fall, the loss on selling back the excess would be borne by ComEd's Fixed Price customers. (ComEd Response at 10)

In ComEd's view, there is no basis for taking this unnecessary risk. ComEd believes the Plan's requirement that ComEd submit an updated forecast in March provides the RS with assurance that any curtailments will be based on the most accurate and up-to-date information. ComEd believes the Commission should reject the RS' recommendation to utilize an average of high and low forecasts rather than the more appropriate base forecast. (ComEd Response at 10)

ComEd notes the RS recommends that the Commission include an additional comment period when the ComEd load forecast is updated in March 2014. Consistent with the Commission's previous decisions, ComEd asserts the request is unreasonable and unworkable, and should be rejected. (ComEd Response at 11)

ComEd states by the time it submits its March update, the Commission will have already approved the lion's share of its forecasted load and the methodology used to calculate its load. According to ComEd, the purpose of the March update is merely to update the inputs to the forecast to reflect only any changes that may occur over the period since the forecast was presented in this docket in July. ComEd claims the issues about the forecast on which there can be debate, as well as the vast majority of the result, will have already been submitted, reviewed, litigated, and approved in this formal docket. By the time the Commission enters its final order, ComEd says the RS (and any other interested party) will have had ample opportunity to fully vet ComEd's process and methodology for calculating its load forecast. Consistent with previous years, ComEd says the purpose of its March update is highly limited and highly focused. ComEd asserts that using the exact same methodology as here approved, the March submission will only be updated with the latest available data, including the expected load changes due to customer migration as a result of additional municipal aggregation referenda. ComEd believes it is both unnecessary and, given the timing and purpose of the data update, improper to re-litigate these issues. (ComEd Response at 11)

ComEd maintains it has extensive experience and expertise in the area of load forecasting. ComEd notes this is the sixth annual procurement proceeding in which the IPA has developed a procurement plan for ComEd, and, as the Commission stated last year, there have been no “serious controversies regarding the load forecasting methodologies or the results of the load forecasts produced by AIC or ComEd, including the routine updates provided by ComEd during the pendency of the previous procurement proceedings.” ComEd says the Commission has noted ComEd has no incentive to over-forecast or under-forecast, thus ensuring the neutrality of its updates. (ComEd Response at 12)

ComEd also claims the March update is not a unilateral or unchecked filing by ComEd. ComEd notes the March update is subject to scrutiny and approval by Staff and the IPA, which further ensures the accuracy of the update. ComEd believes the process set forth in the Plan for submitting and approving ComEd’s March 2013 updated load forecast is consistent with past decisions and best accomplishes the statutory requirement of providing customers with “electric service at the lowest cost over time.” In ComEd's view, the RS' proposal should be rejected. (ComEd Response at 12)

ComEd notes that in its Objections, AIC recommends the Commission hold that “the forecast update for November 2014 through May 2015 … be submitted to the IPA independent of the five year forecast (June 2015 through May 2020) associated with the next Plan. In the interests of providing greater clarity to the procurement process, ComEd supports this recommendation and requests the Commission adopt AIC’s proposed modification to the Plan. (ComEd Response at 12-13)

7. Commission's Conclusions

The Commission will first address the RS' proposal for adoption of load forecast values that are midpoint values between the utilities’ high and low load forecasts because it claims such forecasts would more appropriately recognize that the most significant risk associated with the 2014-2015 procurement year is the risk of substantial re-migration of eligible retail customer load to the electric utilities. WOW believes the utilities’ base load forecasts should reflect no changes due to load migration or in the alternative should reflect a migration of load from the ARES to the utilities as proposed by the RS.

ComEd, AIC, and the IPA, oppose the RS' proposal. While the three parties each filed individual Responses to Objections and Replies thereto, it appears to the Commission that substantively many of the arguments are similar and in the interest of efficiency they will be discussed generically with regard to this issue. They primarily argue that the RS proposal artificially creates an average of values that were not meant to be averaged. They claim the utilities develop their base case forecast first; the high and load cases are then excursion cases where variables and assumptions are changed from the base case based upon informed modeling. They contend the base case forecasts are inherently not meant to be symmetrical, which is why the base case is not the midpoint between the high and low forecasts. They believe the rationale behind any changes to the base, high, or low forecast should be based on the specific inputs to that specific forecast, not simple averaging. They also claim the RS proposal increases the risk of additional costs being imposed on eligible retail customers to the benefit of the LTPPA suppliers.

In reviewing load forecasts during previous procurement proceedings it has become obvious to the Commission that load forecasting is a complex undertaking. As the Commission understands it, the load forecasts are based upon mathematical models with various independent variables. The values (expected, high, and low) of the independent variables are estimated and the load forecasts are produced. If the RS had objections with respect to some aspect of the mathematical models or the specific inputs to the models, the Commission would certainly be interested in its view. While the RS asserts the nature and tight time frames for this proceeding do not provide a reasonable opportunity to develop and present a new methodology, the Commission believes that is precisely one purpose of this proceeding.

In the 2013 procurement proceeding, the Commission observed that there have been few substantive disputes regarding the underlying load forecasts of AIC or ComEd. The Commission believes this is true primarily because load forecasting is complex, the utilities have extensive experience and expertise in the area of load forecasting and the utilities have no economic incentive to develop a biased load forecast. The Commission believes actual experience has proven these observations true and AIC and ComEd have performed quite well in developing load forecasts.

It is not entirely clear that the RS have reviewed the load forecasts in any meaningful detail. Instead, it appears the RS noticed what it viewed as an anomaly, asymmetric load forecasts, and proposed a simple solution. In the Commission's view, the RS proposal is overly simplistic. As ComEd and the IPA point out the load forecasts are intentionally asymmetrical. In conclusion, the record of this proceeding contains no basis for adopting the RS proposal.

In addition to the proposal discussed immediately above, the RS recommends that the Commission, in its order in this docket, provide that: (1) the utilities should file their Spring 2014 load forecast updates with the Commission in this docket; (2) there should be a brief period (7 to 14 days) after the Spring 2014 load forecasts are filed during which interested parties can submit comments on the updated load forecasts;

and (3) the Commission should then issue a supplemental order in this docket either adopting the updated load forecasts, adopting the updated load forecasts with adjustments, or rejecting the updated load forecasts and directing that the load forecasts adopted in the Commission's December 2013 order in this docket be used for purposes of the 2014 Procurement Plan, including the final determinations of whether the RPS rate impact limits are exceeded and curtailments of REC purchases under the LTPPAs are needed for either electric utility. WOW makes a similar suggestion.

This RS proposal is opposed by ComEd, AIC, the IPA, and Staff. Among other things, they argue that RS' proposal is inconsistent with the Commission's prior practice which they believe has been effective. They also claim that the Spring load forecast is essentially an update of inputs to the load forecasting model, which is to be litigated in this proceeding. Finally, they believe any RS' concerns about the review of the forecasts should be allayed by the fact that the utility forecasts are subject to review by the IPA, Staff as well as the Procurement Administrator and Monitor, should they be retained.

The Commission understands that the RS is concerned with the potential impact of any updated load forecast as it has an economic interest in the potential impact on LTPPA curtailment. On the other hand, the Commission is reassured that those traditionally responsible for preparing and reviewing the updated forecast have no economic incentive to produce, or allow to be produced, a biased forecast. The Commission notes the RS request a brief period of 7 to 14 days to submit comments on the updated forecast. Based on the August 15, 2013 posting of Draft Plan by the IPA, the RS had significantly more time to review the load forecasts than it proposes to review the updated forecasts. The nature of the RS' review, comments, and recommendations regarding the load forecasts suggest to the Commission that approving the RS' proposal would serve no meaningful purpose.

As noted above, if the RS had objections with respect to some aspect of the mathematical models or the specific inputs to the models, the Commission would certainly be interested in its views because that is one purpose of this proceeding. Given that the RS has not raised a substantive issue with AIC's or ComEd's forecast, the Commission is not inclined to give its recommendations serious consideration.

The Commission also observes that the IPA is an independent state agency created specifically to develop the Procurement Plan as well as to implement the approved Plan. While the Staff, Procurement Administrator, and Procurement Monitor participate in and oversee the IPA's activities, the IPA has responsibility for many of the procurement activities. Despite the concerns expressed by the RS, the Commission is comfortable the process it has previously used has been and will continue to be effective and successful.

As in previous procurement proceedings, between the IPA, Staff, and ComEd/AIC (as well as the Procurement Administrator and Monitor, should they be retained), the Commission believes that technical issues related to load forecasting will be objectively vetted and appropriately addressed. The Commission rejects the RS' proposals.

WOW says the Plan is silent as to whether those forecasts are to be made publically available. WOW notes that in previous years, ComEd has filed its November load forecast in the docket and suggests the utilities could do the same with their Spring load forecasts. WOW believes the data should also be filed on e-docket since the utilities file their November forecasts and post them on e-docket. The proposal to make the Spring forecasts was not contested and Staff volunteers to post the updates on the Commission website. The Commission approves WOW's recommendation and concludes the information should be filed on e-docket in this proceeding.

AIC believes the forecast update for November 2014 through May 2015 should be submitted to the IPA independent of the five year forecast (June 2015 through May 2020) associated with the next Plan. AIC says the November 2014 through May 2015 forecast update will not become part of the docketed proceeding in the next Plan. AIC believes the language as currently proposed in the Plan could lead to confusion and hence recommends clarifications. The IPA, Staff, and ComEd all concur in this clarification and no party opposed it. The Commission concludes that AIC's proposed clarification is reasonable and should be adopted.

F. Procurement Process and Timing Issues

1. Exelon's Position

In Exelon's view, the Commission and the IPA have made great strides over the years to refine the procurement process, and can and should continue to improve the process in order to minimize the effects of market volatility, to the extent possible. Exelon recommends that procurements be scheduled for the early part of the week, preferably Monday, although Tuesday is acceptable. Exelon says gas storage numbers come out every Thursday, which makes the energy market more volatile for a period of time prior to and after those numbers come out. Exelon claims compounding this volatility would be to conduct procurement events on Fridays as bidders will have to hold bids open over the weekend. Exelon says the longer that bids must remain open, and be subject to the possibility that bids will be rejected, the greater the likelihood that consumers will ultimately be economically harmed. In Exelon's view, these risks are particularly important in procurement events involving block energy products, given the natural volatility that is inherent in the energy market. Exelon says potential suppliers have to incorporate such risks in their bids, which necessarily translates into bid prices to the detriment of consumers. Exelon believes that risk can be easily removed from the procurement process by scheduling procurement events for the beginning of the week. (Exelon Objections at 11)

Exelon also suggests 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. Exelon says both the IPA and the Commission are to be commended for reducing the time period between submission of bids and contract execution over the years. Exelon says the 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. However, Exelon believes further improvements can be made in shortening the time period for "informal" notification to potentially winning bidders. (Exelon Objections at 11-12)

Exelon asserts 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. Citing Section 16-111.5(d)(3) of the PUA, Exelon says such a result is consistent with the legislative mandate. (Exelon Objections at 12)

Given that the block energy products are standard wholesale energy products, Exelon claims the review of these bids should be relatively straightforward, and should not require additional review time. Exelon says it 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. Exelon asserts that any time that can be further reduced off of the current process is of benefit to suppliers, and therefore ultimately will inure to the benefit of ratepayers. (Id.)

Exelon believes that ideally, bids would be submitted in the morning with results as to likely winning bidders provided by 2:00 PM that day or bids would be submitted at the end of day with results as to the likely winning bidders provided that evening. Exelon maintains that the review of bids for standard block energy products should be relatively straightforward, and should not require additional time. (Id.)

Exelon also believes the timing of the procurements within the overall procurement cycle could likewise potentially benefit from further refinement. Exelon states in previous years' REC procurements were held weeks later than the energy and capacity procurements, thereby delaying the publishing of retail rates, which Exelon believes is unnecessary and detrimental to the retail market. Exelon says completing all procurements that are components of retail rates sufficiently in advance of the delivery period, so that retail rates can be published as soon as possible, is necessary in order to afford customers, suppliers, municipalities, and others the opportunity to make electric supply decisions as soon as possible. (Exelon Objections at 13)

Upon completion of the procurements, Exelon says utilities must run the numbers through their respective rate translation mechanisms to arrive at a particular price per kWh for bundled service customers. According to Exelon, the utilities cannot calculate new rates, and the Commission cannot publish the new "Price to Compare" until after the Commission has approved the procurements. Exelon asserts that publishing retail rates within a matter of days before June 1st, which has occurred in the past, should be avoided. Exelon claims it was difficult for RES 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. Exelon contends delays in release of the tariffs and charges causes substantial confusion and potential competitive harm in the retail market. (Exelon Objections at 13)

Exelon states while a time lag of several weeks may have been beneficial in the early years of the current construct, the IPA, the utilities, and the procurement administrators are by now very familiar with the process, and can manage the procurements smoothly. Exelon suggests the Commission should require that retail rates for the cycle beginning June 1, 2014 be published not later than May 1, 2014. (Exelon Objections at 13-14)

2. RESA's Position

Due to the fact that there were no procurement events held as a result of the 2013 Procurement Plan, RESA notes there was no problem with the publication of new rates sufficiently in advance of their effective dates, unlike the experience in previous years.

RESA asserts that delays in the release of utility tariffs and charges cause substantial confusion and competitive harm in the retail market. While the IPA includes some improvements in the procurement process in the 2014 Procurement Plan, RESA says it does not commit to accelerating the publication of new rates in advance of their effective dates. In RESA's view, the Commission should, in its order in this proceeding, 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. (RESA Objections at 9-10)

In its Reply Brief on Exceptions, RESA notes Exelon also proposed improvements to the procurement process to benefit all parties and to result in the publication of default rates sufficiently in advance of their effective dates. RESA supports Exelon’s proposals. (RESA RBOE at 4)

3. ICEA's Position

ICEA states as noted by Exelon, it is difficult for RES 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. ICEA says delays in release of the tariffs and charges causes substantial confusion and potential competitive harm in the retail market. ICEA notes Exelon recommends that retail rates be published no later than one month before their effective date. ICEA says RESA likewise indicates that delays in release of utility tariffs can cause confusion and competitive harm in the retail market, and therefore recommends that the Commission establish schedules that include a requirement that utilities file tariffs and charges not less than two weeks before they would become effective. ICEA agrees with concerns regarding publishing of retail rates and its effect on the retail market, and recommends that retail rates be published on a schedule as set by the Commission, ideally one month before their effective date. (ICEA Response at 7)

4. Commission's Conclusions

Exelon recommends that procurements be scheduled for the early part of the week, preferably Monday, although Tuesday is acceptable. Exelon says gas storage numbers come out every Thursday, which makes the energy market more volatile for a period of time prior to and after those numbers come out. Exelon also suggests 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.

RESA recommends that the Commission 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. ICEA agrees with concerns regarding publishing of retail rates and its effect on the retail market, and recommends that retail rates be published on a schedule as set by the Commission, ideally one month before their effective date.

The Commission appreciates the concerns and suggestions of Exelon, RESA, and ICEA. The Commission, however, is not inclined to micromanage the procurement process which the IPA has effectively administered in previous years. As a result, the Commission will not adopt the recommendations of Exelon, RESA, and ICEA. The Commission does encourage the IPA, Staff, the Procurement Administrator, and Procurement Monitor to take these concerns into consideration when planning and executing the procurement process.

G. Supply Contracts

1. AIC's Position

AIC notes the Plan recommends that prior contracts be used in this and future plans given that parties have had considerable input in prior language and the process by which input is solicited is time consuming and expensive. AIC says the Plan also states the amount of comments has declined significantly relative to earlier procurements and therefore the review process has reached a point of diminishing returns. (AIC Objections at 7)

AIC states the Plan also notes that contracts from prior procurement events cannot be automatically used in future procurement events given that markets are so dynamic. (Id.)

AIC says the Plan indicates that the energy contract used in the last procurement event (Rate Stability Procurement in 2012) will form the starting point for the upcoming contract. AIC recommends this language be expanded in the Plan so as to more specifically define the process by which the energy contract terms will be identified. Specifically, AIC recommends that the IPA, Staff, Procurement Administrator, Procurement Monitor and AIC undertake a joint review of the 2012 energy contract in order to identify what terms, if any, need to be modified. AIC suggests once consensus is reached among these parties, the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used 2012 energy contract. If consensus to a change cannot be reached among the parties, then AIC suggests the provision in the 2012 energy contract would be used. AIC recommends this proposal be stipulated within the Plan and approved by the Commission. (AIC Objections at 4-5)

2. The IPA's Position

The IPA notes AIC requests that the language regarding the use of previous supply contracts as the starting point for new supply contracts be expanded to include more definition of the process used. The IPA agrees with this request, and adds some language to note that any proposed changes from suppliers must achieve the consensus of the relevant utility, the IPA, Staff, the Procurement Administrator, and the Procurement Monitor. Also, the IPA proposes that if consensus cannot be achieved amongst the relevant utility, the IPA, Commission Staff, the Procurement Administrator, and the Procurement Monitor, that the default will be the 2012 contract language. The IPA proposes the following change to the Procurement Plan:

> The IPA therefore recommends that the energy contracts used in the February 2012 Rate Stability procurements be the starting point for the contracts used in the energy procurements associated with this plan <u>and the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of the 2012 energy contract in order to identify what terms, if any, need to be modified. Once consensus is reached among these parties, the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used 2012 energy contract. If based upon supplier comments, consensus to a change cannot be reached among these reviewing parties, then the provision in the 2012 energy contract would be used.</u>

(IPA Response at 21-22)

The IPA says that in its Response, Staff supported AIC's proposed language, although Staff did not have the opportunity to see the IPA's replacement language first. The IPA continues to support its modification to AIC's proposed language, and recommends that the Commission adopt that language. (IPA Reply at 13-14)

3. Staff's Position

AIC recommends that the IPA, Commission Staff, the Procurement Administrator, the Procurement Monitor and AIC undertake a joint review of the 2012 energy contract in order to identify what terms, if any, need to be modified. Staff says under this proposal, once consensus is reached among these parties, the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used 2012 energy contract. If consensus to a change cannot be reached among the parties then the provision in the 2012 energy contract would be used. AIC recommends this proposal be stipulated within the Plan and approved by the Commission. In Staff's view, this proposal reasonably streamlines the process of reviewing and updating standard energy contracts, where appropriate. (Staff Response at 23)

4. Commission's Conclusions

AIC recommends that the IPA, Staff, Procurement Administrator, Procurement Monitor, and AIC undertake a joint review of the 2012 energy contract in order to identify what terms, if any, need to be modified. AIC suggests once consensus is reached among these parties, the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used 2012 energy contract. If consensus to a change cannot be reached among the parties then, AIC suggests the provision in the 2012 energy contract would be used. AIC recommends this proposal be stipulated within the Plan and approved by the Commission.

AIC's proposal was endorsed by Staff and the IPA. The IPA provided specific language intended to accomplish this goal.

The Commission finds that AIC's proposal is reasonable and it is hereby approved. The Commission also finds the language provided by the IPA to be reasonable and it is approved.

H. Miscellaneous and Technical Issues

ComEd, ICEA, and AIC each provided redline versions of the Plan submitted by the IPA with their proposed changes. (See ComEd Objections at 9, ICEA Objections at 1, AIC Objections at 1) In some instances, those documents identified typographical errors, scriveners' errors, clerical errors, and what may be identified as technical errors. AIC and ComEd also identified specific, what they describe as, "technical errors" in their Objections. (AIC Objections at 5-6, ComEd Objections at 8-9) Finally, the RS identifies changes that it believes are necessary to the Action Plan set forth on page 14 of the IPA Plan to incorporate its Objections to the Plan. (RS Objections at 21-22)

The IPA notes AIC identified several labels and titles on Figures and Tables that need to be updated (IPA Response at 22, citing AIC Objections at 5-6), and minor wording changes to Sections 7.1.1, 7.1.2 and 7.1.4.1 (AIC Objections at 9 and 12). The IPA agrees.

The IPA also notes ComEd proposes several technical corrections regarding clarifying which parties are part of the consensus decision making process for approving curtailment of LTPPAs (IPA Response at 22, citing ComEd Objections at 8-9) and miscellaneous typographical corrections contained in their redlined version of the Plan. The IPA agrees with these suggestions.

Staff indicates it does not object to AIC's technical suggestions. However, Staff is uncertain that AIC's suggestion will clarify the facts presented in Figures 4-2, 4-3 and 4-4. Staff says these are "stacked" area graphs, where it is implied that the top line of each area represents the cumulative sum of each of the areas beneath. Staff suggests clarifying the graphs by switching the order of the "RSP" series and the "20-Yr. RPS Contracts" series (so that the7x24 annual blocks are shown at the bottom). If it is determined that the cumulative nature of graphs is still unclear, then Staff believes it may be enough to add a note that these are stacked area graphs. (Staff Response at 25)

AIC and ComEd propose certain technical corrections to the Procurement Plan. The IPA and Staff suggest these corrections should be adopted, although Staff proposes a minor modification to one of AIC's proposal.

The Commission concludes that the agreed-upon technical corrections to the Procurement Plan are reasonable and they are hereby adopted.

V. 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 30, 2013 petition should be approved; the load forecast for ComEd attached to the IPA's September30, 2013 petition should be approved;

(5) subject to the modifications adopted in the prefatory portion of this Order, including such recommendations and objections as are approved above, pursuant to Section 16-111.5B(a)(5) the Commission approves the energy efficiency programs and measures included in the Plan;

(6) subject to the modifications adopted in the prefatory portion of this Order, including such recommendations and objections as are approved above, 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.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications 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, as are the load forecasts found appropriate above.

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 18th day of December, 2013.

(SIGNED) DOUGLAS P. SCOTT

Chairman