STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	**14-0588**
Petition for Approval of the 2015	**:**	
IPA Procurement Plan pursuant to	**:**	
Section 16-111.5(d)(4) of the Public	**:**	
Utilities Act.	**:**	

ORDER

DATED: December 17, 2014

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By the Commission:

I. BACKGROUND

As set forth more specifically therein, Section 16-111.5(d)(2) of the Public Utilities Act ("PUA"), 220 ILCS 5/1-101 et seq., requires the Illinois Power Agency ("IPA") to prepare a power procurement plan ("Draft Plan"), which is to be posted on the IPA and Illinois Commerce Commission ("Commission") websites. Among other things, the purpose of the power procurement plan is to secure electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company d/b/a Ameren Illinois ("AIC" 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 29, 2014, the IPA filed with the Commission its seventh annual power procurement plan ("Plan," "IPA Plan" or "IPA 2015 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 29, 2014; thus, the deadline is December 28, 2014. 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 RFPs shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price. Section 16-111.5(f) concerns the confidential reports to be submitted to the Commission by the Procurement Administrator and Procurement Monitor after the opening of the sealed bids. Subsection (f) provides further that the Commission shall review the confidential reports submitted by the Procurement Administrator and Procurement Monitor, and shall accept or reject the recommendations of the Procurement Administrator within two business days after receipt of the reports.

II. PROCEDURAL HISTORY

Following the receipt of the IPA's Plan on September 29, 2014, 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"); Exelon Generation Company, LLC ("Exelon"); Illinois Competitive Energy Association ("ICEA"); Retail Energy Supply Association ("RESA"); Comverge, Inc. ("Comverge"); the Environmental Law & Policy Center ("ELPC"); the Illinois Solar Energy Association ("ISEA"); the Illinois Coal Association ("ICA"); the International Brotherhood of Electrical Workers Local 146 ("IBEW"); the Plumbers & Steamfitters Local 149 Untied Association ("Plumbers & Steamfitters"); and the Illinois Industrial Energy Consumers ("IIEC"). 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 6, 2014 Objections to the Plan were filed by the RS, ComEd, AIC, Exelon, ICEA, RESA, Staff, ELPC[1], NRDC, and ICA. On October 7, 2014 ISEA and CUB filed Objections, October 8, 2014 Sargas filed Objections, and October 10, 2014 IBEW filed Objections. On October 14, 2014 the Plumbers & Steamfitters filed Objections.

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 NRDC, the IPA, AIC, the AG, Staff, Exelon, RESA, CUB, ComEd, ICEA, ISEA, ELPC, and Comverge. Thereafter, Replies to Responses were filed by the above-named Intervenors except Exelon. Replies to Responses were also filed by Sargas, the RS and IIEC.

[1] The Reply to Responses of CUB was filed jointly with the Environmental Defense Fund ("EDF") who has to date not properly intervened in this Docket.

A Proposed Order was served on the parties. Briefs on Exception were filed by the IPA, Ameren, CUB[2], RESA, ICEA, Staff, NRDC, ComEd, the RS, and Sargas. Replies to Briefs on Exception were filed by NRDC, RESA, ICEA, the IPA, AIC, Staff, ComEd, IIEC, the AG, and Comverge.

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

This section of the Order describes the IPA's Plan as filed on September 29, 2014, 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, this is the seventh electricity and renewable resource procurement plan prepared by the IPA under the authority granted to it under the IPA Act and as further regulated by the Illinois PUA.

The IPA says the Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren and ComEd as defined in Section 16-111.5(a) of the PUA. Section 16-111.5 of the PUA defines "eligible retail customers" as:

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

The Plan considers a 5-year planning horizon that begins with the 2015-2016 delivery year and lasts through the 2019-2020 delivery year.

The IPA reports that the 2014 Procurement Plan was approved by the Commission in Docket No. 13-0546. That plan recommended a return to the procurement of electricity after no procurement was conducted in 2013, and a number of refinements to the procurement process including an updated hedging strategy, smaller procurement blocks and a second procurement in September, 2014. The IPA says it was the second plan that included incremental energy efficiency programs as mandated by Section 16-111.5B of the PUA.

The Plan recommends a refinement of the procurement strategy for electricity adopted for 2014. The IPA says this strategy relies on the IPA's analysis of the load forecast scenarios, the position of the supply portfolio, and the IPA's analysis of the risks associated with serving electric load and various factors of power procurement. The IPA claims that in response to a specific directive from the Commission in the approval of last year's plan, that analysis of risks carefully examines the concept of the

[2] The Brief on Exceptions of CUB was filed jointly with EDF who to date has not properly intervened in this Docket.

IPA procuring full requirements products, rather than the IPA's traditional approach of procuring standard blocks of power. The IPA concludes that a full requirements approach in lieu of standard blocks does not best serve the interests of the eligible retail customers that the IPA is directed by the General Assembly to serve. The Plan includes a proposal to conduct a procurement of energy efficiency as a supply resource for delivery starting in the summer of 2016. The IPA says the Plan also recommends a procurement of Solar Renewable Energy Credits ("SRECs") and Renewable Energy Credits ("RECs") from distributed generation resources.

The IPA indicates the Plan proposes to continue using the risk management and 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. While the IPA again this year investigated alternative strategies, such as full requirement contracts and use of options, the IPA believes the continuation of its previous, tested risk management strategy is the most prudent, most reasonable, and the most likely to meet 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.

According to the IPA, the proposed hedging strategy in the short-term (prompt delivery year) 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. Based on the analysis of the costs of procurement and supply shortfalls, the IPA recommends a refinement of the procurement approach adopted in 2014 for use in the procurement of power for delivery year 2015-2016 and beyond. Consistent with the 2014 Plan, the IPA also recommends procurement of energy in blocks of 25 megawatts ("MW"). The IPA says the risk management strategy will continue to bifurcate the first delivery year into periods with different hedging levels - with June hedged 100% of average load, July and August hedged to 106% of average on-peak load and 100% of average off-peak load, September and October hedged to 100% of average load at the time of the April procurement event. The IPA recommends that the Commission approve a September procurement event, which would bring the hedging level for the balance of the first delivery year (November through May) to the fully hedged level (100% of load).

Consistent with the 2014 Plan, the IPA recommends hedging 50% of the expected load for the second delivery year and 25% of the expected load for the third delivery year. The IPA, for this Plan, recommends the procurement of half of these volumes in the April 2015 procurement event and the balance in the September 2015 procurement event.

The IPA also recommends the procurement of energy efficiency as a supply resource for delivery starting in June 2016. The IPA says this proposed procurement is intended to reduce the overall cost of procuring supply for eligible retail customers. 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") (formerly Midwest Independent Transmission System Operator, Inc.) marketplace and by ComEd from the PJM Interconnection, L.L.C. ("PJM") marketplace.

Additionally, the IPA recommends purchasing capacity to satisfy a portion of the capacity requirement for Ameren for the second delivery year. The IPA recommends a September 2015 procurement event for at least 50% of the forecast requirement for the second delivery year and potentially, subject to the consensus among the IPA, Commission Staff, and Procurement Monitor, at least 25% of the forecast requirement for the third delivery year.

The following tables summarize the IPA's proposed hedging strategy.

Summary of Proposed Energy Hedging Strategy					
April 2015 Procurement			September 2015 Procurement		
June 2015-May 2016 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	November 2015-May 2016	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. and Oct. 100% peak and off peak Nov. - May 75% peak and off peak	25%	12.5%	100%	25%	12.5%

Summary of Capacity Hedging Strategy			
	June 2015-May 2016 (Upcoming Delivery Year)	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
Ameren	100% MISO Auction*	50% RFP in Sep. 2015	25% RFP in Sep. 2015**
ComEd***	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

NOTES:
* MISO Auction is expected to clear in April 2015.
** Subject to the consensus among the IPA, Staff, and Procurement Monitor.
*** PJM RPM Base Residual Auctions for 2015-16, 2016-17 and 2017-18 have already cleared; although there may be incremental auctions for additional capacity needs they should have little impact on the PJM capacity prices for those years.

The IPA reports that the load forecasts supplied by the utilities on July 15, 2014 indicate that existing renewable energy resources under contract do not meet or exceed the Renewable Portfolio Standard obligations for solar resources or distributed generation for eligible retail customers. Accordingly, the IPA recommends conducting procurement events for solar RECs using the renewable resources budget and for

distributed generation RECs using hourly Alternative Compliance Payment ("ACP") funds.

The IPA says while it is highly unlikely that the statutorily mandated rate caps for the renewable resources budget will be exceeded in the 2015-16 delivery year for either utility, the IPA recommends that the Commission pre-approve a curtailment of the long-term power purchase agreements that were entered into as part of the 2010 procurement should the utility load forecast updates in Spring 2015 indicate that a curtailment is necessary. The IPA says this is a similar approval process as was adopted in last year's plan. Given that the IPA is planning a procurement of distributed generation ("DG") resources using collected hourly ACP funds, the IPA recommends the hourly Alternative Compliance Payments funds available for that procurement be reduced by the amount needed ensure full payment of any 2014-2015 curtailed RECs. In addition, should a curtailment of the long-term power purchase agreements be necessary for the 2015-2016 delivery year, the amount of funds available for the DG procurement will be likewise adjusted.

The following tables summarize the IPA's proposed supply-side procurements.

IPA Recommendations Based on July 15, 2014 Load Forecasts

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	**2015-16**	Up to 875 MW forecasted requirement (April Procurement) Up to 275 MW additional forecasted requirement (September Procurement)	100% direct purchase from MISO capacity market	One-year SRECs procurement up to 30.2 GWh[3] Five-year DG REC procurement up to 6.5 GWh. No RPS[4] procurement for other resources, target exceeded	Will be purchased from MISO
	2016-17	Up to 200 MW forecasted requirement (April Procurement) Up to 200 MW forecasted	50% solicited via bilateral September RFP	No RPS procurement or sales: target exceeded (except for DG using hourly ACP funds)	Will be purchased from MISO

[3] Gigawatt-hour is abbreviated as "GWh" in the remainder of this Order.
[4] Renewable Portfolio Standard is abbreviated as "RPS" in the remainder of this Order.

		requirement (September Procurement)			
	2017-18	Up to 150 MW forecasted requirement (April Procurement) Up to 125MW forecasted requirement (September Procurement)	25% solicited via bilateral RFP subject to consensus	No RPS procurement: shortage of 94 GWh, revisit next year	Will be purchased from MISO
	2018-19	No energy procurement required	No further action at this time.	No RPS procurement: shortage of 457 GWh, revisit next year	Will be purchased from MISO
	2019-20	No energy procurement required	No further action at this time.	No RPS procurement: Shortage of 564 GWh, revisit next year	Will be purchased from MISO
C O M E D	**Delivery Year**	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
	2015-16	Up to 1,950 MW forecasted requirement (April Procurement) Up to 550 MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	One-year SRECs procurement up to 49.8 GWh Five-year DG REC procurement using hourly ACP funds up to 13.2 GWh No RPS procurement or sales for other resources, target exceeded	Will be purchased from PJM
	2016-17	Up to 375 MW forecasted requirement (April	Direct purchase from PJM capacity	No RPS procurement: shortage of 120 GWh, revisit	Will be purchased from PJM

		Procurement) Up to 375MW forecasted requirement (September Procurement)	market	next year	
	2017-18	Up to 175 MW forecasted requirement (April Procurement) Up to 200MW forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	No RPS procurement: shortage of 428 GWh, revisit next year	Will be purchased from PJM
	2018-19	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 888 GWh, revisit next year	Will be purchased from PJM
	2019-20	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: shortage of 1,124 GWh, revisit next year	Will be purchased from PJM

The Commission understands that the energy volumes in the above table are preliminary and the IPA plans for them to be adjusted using the March 2015 expected load forecasts, which will also include newly approved energy efficiency programs.

The IPA reports that after examining the concept of energy efficiency as a supply resource in the draft 2014 Procurement Plan, and after conducting a workshop and receiving written comments early in 2014, the IPA is proposing a procurement of energy efficiency as a supply resource. The proposal is for the procurement for “super-peak” summer weekday blocks. To work through potential challenges and allow the market to properly organize, the IPA is proposing that the procurement be held in late 2015, for delivery starting in 2016, and to ensure that the procurement is structured to lower the overall supply portfolio cost. In the alternative the IPA also recommends consideration of a strategy that would update the Section 16-111.5B third-party RFP process to accomplish a comparable result.

According to the IPA, this Plan is the third 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 and have not been determined to be duplicative of other programs as

discussed in Section 7.2. The IPA further recommends the approval of the consensus items from the Staff-led workshops held earlier this year.

The IPA recommends the following items for Commission action:

1. Approve the base case load forecasts of ComEd and Ameren as submitted in July 2014.

2. Require the utilities to provide an updated March 2015 forecast which will be pre-approved by the Commission in this docket subject to the March 2015 consensus of each utility, the IPA, Commission Staff, and the Procurement Monitor.

3. Pre-approve the July 2015 base case load forecast for the purpose of procuring the target energy volumes for ComEd and Ameren, and the target capacity amount for Ameren in September, subject to the review and consensus of the IPA, Commission Staff, and the Procurement Monitor.

4. Approve two energy procurements scheduled for April 2015 and September 2015. The energy amounts to be procured in April will be determined by the IPA based on the updated March 2015 load forecast and in accordance with the hedging levels stated in this Plan and as ultimately approved by the Commission in this docket. The energy amounts (and capacity for Ameren) to be procured in September will be determined by the IPA based on the July 2015 expected load forecast developed by each of Ameren and ComEd.

5. Require the utilities to expand the July 2015 forecast to include the November 2015 to May 2016 period. The addition of the November 2015 through May 2016 load forecast will have no bearing on the renewable curtailment decisions, if any.

6. Approve continued procurement by ComEd and Ameren of capacity, network transmission service, and ancillary services from their respective regional transmission organization ("RTO") for the 2015-2016 delivery year.

7. Approve a procurement of capacity for Ameren in a quantity of at least 50% of the forecast requirement for the second delivery year and a contingent procurement of at least 25% of forecasted requirements for the third delivery year.

8. Approve pro-rata curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy in the unlikely event that the

updated March 2015 expected load forecast indicates that such a curtailment is necessary. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the parties identified in Item 2 above. Otherwise, the July 2014 forecast will form the basis for curtailment.

9. Approve a Spring 2015 procurement of SRECs for the prompt delivery year to allow the utilities to meet their photovoltaic RPS requirement. The volume for the procurement will be determined based upon the "Remaining Target" quantities from the utilities' March, 2015 load forecasts and limited to the funds available according to the update of Renewable Resources Budgets.

10. Approve a September 2015 procurement of distributed generation RECs using already collected hourly ACP funds.

11. Approve a procurement of energy efficiency as a supply resource to lower the overall cost of supply starting in 2016. In the alternative, the IPA also recommends consideration of a strategy that would update the Section 16-111.5B third-party RFP process to accomplish a comparable result.

12. Approve the consensus items from the Commission Staff-led workshops on Section 16-111.5B.

13. Approve Section 16-111.5B incremental energy efficiency programs.

14. Approve the recommendations to improve the procurement event process.

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 2015 to May 2020 for the 2015 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.

The IPA indicates that Ameren provides a base case and two complete excursion cases: a low forecast and a high forecast. The IPA says each excursion case addresses three different uncertainties that simultaneously move in the same direction: macroeconomics, weather, and switching. This means, for example, that a high load case should represent the combination of stronger-than-expected economic growth (which increases load), extreme weather (which increases load) and a reduced level of switching (which increases the "eligible" fraction of retail load, that is, the fraction for

which the utility retains the supply obligation). Similarly, a low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increased level of switching.

With regard to macroeconomics, the IPA states that the Ameren base case load forecast is based on a Statistically Adjusted End-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). The IPA reports that Ameren did not define “high” and “low” cases by varying the econometric (or other) variables. Instead, Ameren looked at the statistics of the residual from the model fit and the high and low cases are based on a 95% confidence interval. The IPA says Ameren’s “high” and “low” forecasts are uniform modifications of the expected case, excluding incremental energy efficiency, by rate class. Specifically, in each case, a single multiplier is defined for each of the five delivery service rate classes, and the “before switching” load forecast for every hour is multiplied by the rate class multiplier.

Because the excursion cases are based on the statistics of the residuals, the IPA says they reflect the influence of unmodeled variables. In the IPA's view, the forecasting model appears to be dominated by technological and weather effects. The econometric variables are related to short-term decision making. Uncertainty around long-term economic growth will appear in the residuals.

The IPA says Ameren includes “high weather” and “low weather” in its characterization of the high and low cases. The IPA indicates Ameren did not re-compute its load forecasting models with different values for the weather variables. The high and low scenarios only account for an averaged impact of weather, as well as macroeconomics, which is proportionally the same in each hour.

The IPA reports that the difference between the high, low and base cases show the variation Ameren attributes to macroeconomics and weather. The low case is about 5% lower than the base case and the high case is about 9% higher than the base case.

The IPA says that according to Ameren switching, in particular municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2014 has resulted in approximately 65-70% of residential and small commercial load seeking service from alternative suppliers. Ameren expects the amount of load supplied by alternative retail electric suppliers ("ARES") will modestly decline during the summer of 2014 and spring of 2015 based on indications from municipalities that have contracts expiring. Additionally, Ameren’s current year tariff price is lower than comparable ARES prices. As such, Ameren forecasts the residential and small commercial switching rate to decline to 54% and 66%, respectively by June 2015. However, beginning in June 2015, the trend becomes less certain and therefore the Ameren base case predicts flat switching from that point throughout the planning horizon.

The IPA indicates a high load scenario envisions a situation where an even larger return of residential and, to a lesser extent, commercial customers, is realized,

especially in June 2016 when approximately 30% of residential load will see contracts under government aggregation expire. Residential and commercial switching rates under the high load scenario are forecasted to be 44% and 57%, respectively, in May 2016, 16% and 51%, respectively in May 2017, and 12% and 42%, respectively, by the end of the planning horizon.

Conversely, should future Ameren tariff price exceed customers' perceived value of ARES contracts, the IPA says a higher switching scenario is possible. Thus, Ameren's low load scenario assumes that residential and small commercial will approach 73% and 75%, respectively, in May 2016, 78% and 81%, respectively in May 2017, and 87% and 91%, respectively, by the end of the planning horizon. The IPA says the difference in the amount of switching among the three cases is significant.

The IPA reports that like Ameren, ComEd provides a base case and two excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather, and switching. The IPA says the combined impact of the changes in macroeconomics, weather, and switching is estimated to represent a scenario probability range between the 15th percentile for the low forecast and 85th percentile for the high scenario.

The IPA says ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. The high weather case is based on observed temperatures in 1995, and the low weather case on observed temperatures in 2004. These years represent approximately the 90th percentile and 10th percentile of weather impacts on load, respectively. The IPA indicates ComEd has not provided the specific impacts of the load growth assumption (load forecasts in the absence of switching). ComEd did provide the impacts of the weather case on residential and small commercial load, relative to the base case forecast. They are provided as percentages that summarize the hourly impacts of a finer-scale model of the effect of temperature on load. The IPA says the high and low years are not high and low in every month. There are some months, for example, where the impact of the "high weather" year is less than 1.

The IPA states that ComEd's high and low switching cases are moderate relative to Ameren's. The high switching (low load) case assumes residential ARES usage returns to the May 2014 level (approximately 70%) in the summer of 2015 as the communities that are opting for ComEd service renew their programs. In addition, it is assumed that small commercial switching increases slightly over the next 3 years.

The low switching (high load) case assumes additional communities opt for ComEd service beginning in June 2015 such that residential ARES usage declines from approximately 70% of total usage in May 2014 to approximately 54% in June 2017. This coincides with a 1.8 percentage point decrease in small commercial switching over the next 3 years.

1. Load Forecast Uncertainty

The IPA states that in the past, it has procured power for the utilities to meet a monthly 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 does 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.

According to the IPA, 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. 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. The IPA claims 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 says 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 says it is treated together with the other uncertainties.

The IPA says 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 reports 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% and -5%, respectively, in service area load. The IPA says Ameren's high and low cases also include extreme customer migration uncertainty.

According to the IPA, 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 differences of +/-2% in load growth should represent an appropriately representative 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. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. The IPA states that much of the impact of weather is on load variability within the year.

The IPA says the "average hour" load forecast is not an accurate forecast of each hour's load. Within the sixteen-hour daily peak period, mid-afternoon hours would be expected to have higher loads than average, and early morning or evening hours would be expected to have lower loads. More importantly, multiplying the average hourly load by the cost of a "strip" contract (equal delivery in each hour of the period) gives an inaccurate forecast of the cost of energy. The IPA says this is because hourly energy prices are correlated with hourly loads (energy costs more when demand is high). Technically, the IPA says this is referred to as a "biased" forecast, because the expected cost will predictably differ from the product of expected hourly load and expected hourly cost.

In their base cases, the IPA says Ameren projects 57.7% switching by eligible retail customers by the end of the 2015-2016 delivery year and ComEd projects about 63.2%. The IPA says these levels represent a decline in the switching statistics assumed in the July 2013 forecasts and are informed by lower than forecasted actual switching through April 2014 driven in part by communities deciding to suspend and/or not renew their municipal aggregation programs and return to utility service. Savings opportunities that existed prior to 2014 drove the growth in residential switching, but in 2014 these savings began to diminish. The IPA states that at this point, 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.

The IPA indicates that approximately half of the current supply contracts for municipal aggregation will expire in the 2014-2015 delivery year. It is possible 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 suggests 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 (return to utility service would be represented as a decrease in the switching fraction over time).

The IPA notes that ARES offer a variety of products to customers – some of which have a similar structure to the utility bundled service, and some that vary

significantly in structure. These include offers with “green” energy above the mandated RPS level, month to month variable pricing, longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively. The IPA says individual customers who choose one of these other rate structures presumably have made an affirmative choice to take on those alternative services.

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. While the IPA recognizes that many ARES focus on individual residential switching, the IPA is not aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. The IPA says this is currently the case because of the appreciable difference that currently exists between the utility price to compare and representative ARES prices available to eligible utility customers. It appears to the IPA that, at the current time, ARES fixed price offers for a similar term to the utility price do not offer savings or benefit to individual residential customers. The IPA believes it is reasonable to assume that switching behavior by individual customers (other than those who chose an ARES rate that is not an “apples to apples” comparison to the utility rate) 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 states 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, these hourly rate customers are not part of the utilities’ supply portfolio 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 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 reports 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. The IPA says 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. These programs are reflected in the load forecasts.

The IPA says demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that they are more like supply resources.

The IPA notes a number of emerging technologies were described in the 2013 Procurement Plan and two more technologies, advanced metering infrastructure ("AMI") and electric vehicles ("EV"), were described in the 2014 Procurement Plan. The IPA also notes that in Docket No. 14-0212, the Commission approved an acceleration of

ComEd's AMI deployment plan. The IPA is not aware of other emerging technologies that warrant inclusion in the Plan at this time.

The IPA recommends adoption of the Ameren and ComEd base case load forecasts, which include already approved energy efficiency programs. The IPA also recommends that the Commission approve the additional incremental energy efficiency as presented in the Plan. The IPA says the March 2015 load forecasts will also reflect those newly approved programs.

In the IPA's view, the high and low cases represent useful examples of potential load variability. Although they are primarily driven by variation in switching, Ameren correctly notes that this is the major uncertainty in its outlook. The IPA says the switching variability, especially in Ameren's high and low forecasts, is extreme and thus these may be characterized as "stress cases." The IPA notes its 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 Ameren low and high load forecasts are on average equal to 67% and 131% of the base case forecast, respectively, during the 2015-2016 delivery. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 78% and 137% of the base forecast, respectively. The IPA says this reflects the differences in switching assumptions used by the two utilities.

According to the IPA, another use of the high and low cases is to estimate the risks of different supply strategies. The IPA says 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 believes high and low cases are less suitable for such a risk analysis.

The IPA says 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. Using that hourly profile for a risk analysis could lead to underestimating the cost of unhedged supply.

The IPA says Ameren load scenarios have identical monthly load shapes (differing by uniform scaling factors). 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 IPA suggests the expected load shape may have an overstated load factor like that of ComEd, and no other forecast case is available for comparison.

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

2. Existing Resource Portfolio and Supply Gap to Be Filled

Prior to the 2014 Procurement Plan, the IPA purchased supply in standard 50MW on-peak, off-peak, and around-the-clock blocks. For the 2014 Procurement Plan, to more accurately match supply with load, the IPA reduced the block size to 25 MW. 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 by the IPA's Procurement Administrator. This procurement process is monitored for the Commission by the independent Procurement Monitor.

In addition to purchasing block contracts in the forward markets, the IPA reports that Ameren and ComEd rely on the operation of their RTOs (MISO and PJM, respectively) to balance their loads and consequently may incur additional costs or credits. Purchased energy blocks may not perfectly cover the load, therefore triggering the need for spot energy purchases or sales from or to the RTO.

The IPA says procurement plans are based on a supply strategy designed, among other things, to balance 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.

Prior to the 2013 Procurement Plan, the IPA says the first year of the 3-year procurement plan was hedged at 100% (meaning that energy contracts would fully cover the demand), while the second and third years were only hedged at 70% and 35%, respectively. Based on suggestions from Commission Staff, the IPA considered a revision to this strategy (for the energy products only) as part of the 2013 Procurement Plan to account for declining market prices and accelerating customer switching. This proposal was to hedge the first year at 75%, while the second and third year 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. For the 2014 Procurement Plan, the IPA says this strategy was updated to include hedging at 106% of the months of June through October for the first delivery year, and 100% for the balance of the year, 50% for the second year, and 25% for the third year. The 2014 Procurement Plan was also the first plan in which a second procurement, taking place in the fall, was included.

The IPA says because of the uncertainty in the amount of eligible retail load in future years, the IPA has not purchased energy beyond a 3-year horizon, except in a few circumstances. These include:

- A 20-year bundled REC and energy purchase (also known as the long-term power purchase agreements or "LTPPAs"), starting in June 2012, made by Ameren and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.

- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.

Twenty-year power purchase agreements between each of Ameren and ComEd and the FutureGen Industrial Alliance, Inc., although not procured by the IPA, were directed by the Commission order approving the IPA's 2013 Procurement Plan.

Due to the forecasted return of some load to the utilities, the IPA believes curtailment of the LTPPAs is unlikely for the 2015-2016 delivery year for both ComEd and Ameren.

According to the IPA, Ameren's existing supply portfolio, including the Rate Stability contracts and the long-term renewable resource contracts, is not sufficient to cover the projected load for the 2015-2016 delivery period. Additional energy supply will be required for the entire 5-year planning period. The IPA says the main driver for this change from the previous plan is the change in load attributed to switching. On average, Ameren's load forecast produced in July 2014 for the 2015-2019 delivery period is between 64% and 90% higher than the forecast produced in July 2013 for the same delivery period. The IPA states that similarly, ComEd's load forecast produced in July 2014 for 2015-2019 delivery year is between 43% and 62% higher than the forecast produced in July 2013 for the same delivery period.

Under the expected load forecast scenario, the IPA says Ameren's average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 615 MW. Under the high load forecast scenario, the average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 900 MW, while under the low load forecast scenario, Ameren's average supply gap for peak hours of the 2015-2016 delivery period is estimated to be 300 MW.

The IPA reports that ComEd's current energy resources will not cover load starting in June 2015. The average supply gap during peak hours for the 2015-2016 delivery year is estimated to be 1,223 MW. Under the high load forecast scenario, the IPA says ComEd will be consistently short during the whole study period. The average supply gap for peak hours of the 2015-2016 delivery year is estimated at 1,966 MW. Under the low load forecast scenario, ComEd will also be consistently short on average 790 MW for the 2015-2016 delivery year.

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 reliably.

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 PJM will maintain adequate resources to meet the collective needs of customers in those regions. The IPA indicates MISO may be short resources in the 2016 timeframe.

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.

Just prior to the beginning of each DY, the IPA says the Final Zonal Net Load Price, which is the price paid by load serving entities for capacity procured as part of RPM in PJM, is calculated. This price is determined based on the results of the BRA and subsequent incremental auctions for a given delivery year. As the majority of the capacity procured via RPM is done so during the BRA, the IPA says there is little variation between the BRA clearing price and the Final Zonal Net Load Price. The IPA claims the price volatility that does exist under RPM is inter-temporal across delivery years. The IPA states while this volatility is large, it is not hedgeable.

According to the IPA, PJM is projected to have sufficient resources to meet load plus required reserve margins from 2014-2019, 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, 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, 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 indicates MISO held its second annual capacity auction in April 2014, with capacity prices in the majority of zones clearing up to 15 times higher than in the first auction due potentially to a tightening of the capacity reserve margin in MISO ($16.75/MW-day for the 2014/15 delivery year versus $1.05/MW-day for the 2013/14 delivery year).

The IPA reports that MISO is projected to be short capacity supply to meet load plus target reserve margins for the delivery years 2014-2019, with reserve margins averaging less than 10% during this period. The IPA says this is approximately 4% below the 14.2% target reserve margin. The IPA also reports that on September 8, 2014, MISO released the third draft of the 2014 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. In this MISO report, the IPA says reserve margins are projected to be on average higher than the Schedule 3A data. Relying on the draft MISO data, reserve margin in 2016 is only 0.2% below the target reserve margin.

The drop in reserve margin beginning in 2015 is primarily attributable to the assumed retirement of coal generation due to environmental regulations (i.e., the implementation of the Mercury and Air Toxics Standards, "MATS," in 2016) and fuel prices. The IPA asserts the assumed 8 gigawatts ("GW") of coal retirements by 2016 represent a worst case scenario and likely do not fully account for environmental compliance investments or coal-to-gas conversion decisions by these facilities. Additionally, the IPA says NERC has suggested that some, if not all, of the projected

shortfall by 2016 could be mitigated by future-planned additions, DSM growth, additional support anticipated from the MISO South Region, and transmission upgrades. In the third draft of the 2014 MTEP report, MISO also states that “the projected margin shortfall will likely change significantly as Load Serving Entities and State commission solidify future capacity plans.” As such the IPA suggests the MISO capacity projection may need to be updated when more reliable data is available.

The IPA states that the RTO-based reliability assessments are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. The IPA concludes that it does not need to include any extraordinary measures in the 2015 Procurement Plan to assure reliability over the planning horizon. Even so, the IPA indicates the differences between the PJM and MISO capacity auction constructs have led the IPA to recommend hedging some of Ameren’s capacity market exposure beyond the prompt year.

The IPA notes in 2013, MISO integrated Entergy into MISO creating the MISO South Region. The MISO South Region adds over 18,000 miles of transmission and approximately 30 GW of load into the MISO footprint. The IPA says generators in the MISO South Region are dispatched and bid into the MISO markets. The IPA says the load/resource balance associated with the South Region has yet to be incorporated in NERC projections.

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 impacts 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.

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 LTPPAs 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 ("LSEs") 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.

According to the IPA, the 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges. The IPA says one point made in that plan is that hedges available in the market are not perfect. The IPA states that the risks cannot all be hedged away except through a specially tailored "full requirements" hedge contract, whose cost may or may not be acceptable in return for that degree of risk reduction. 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 asserts that not all of the types of hedges are suitable for use in the Procurement Plan, and not all may 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 the procurement process must satisfy, and mandates that the results be accepted by the Commission. Among the specific requirements, the Procurement Administrator must be able to develop a market price benchmark for the process; the bidding must be competitive; and the Commission's Procurement Monitor 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.

The IPA believes hedges most suitable for use by the IPA 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, a bidder can control its risk exposure. The IPA says 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. Prior to its 2014 Procurement Plan, the IPA says it had generally restricted its hedging to the use of standard forward hedges in 50 MW increments. The IPA began using 25 MW increments and a mid-year procurement with the 2014 Plan. 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 indicates it has in the past purchased energy products that are not typically traded, such as the LTPPAs with new build renewable generation that were authorized in the 2010 Procurement Plan. The IPA says 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. According to the IPA, while the Commission clarified its understanding of the definition of "standard product" in its approval of the 2014 Procurement Plan, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could be subject to future litigation. The IPA claims markets for products that are specifically designed for the IPA's requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process and may not be compatible with such a low level of transparency.

The IPA states that 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, however. The IPA says it ought to be able to obtain competitive pricing on such contracts if it were to want to incorporate them in its portfolio. However, the IPA suggests it may be difficult or impossible to conduct the statutory RFP process for exchanged-traded futures contracts; setting a price through an RFP process structured per legislative mandates is incompatible with price-setting either in an open outcry auction or by a market-maker. In the IPA's view, it is also unclear how the margin requirements would fit within the current regulatory framework, if price movements require the utility to post margin many months in advance of delivery. The IPA says the same concerns are even more applicable to options contracts, trading in which is more illiquid.

The IPA indicates that an option gives the buyer a right but not an obligation. For example, 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. Options are "one-way" hedges. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. The IPA says

options on forward or futures contracts are much less expensive than the contracts themselves, because they only convey the right to spend the money to buy the contract.

The IPA notes some may perceive options as attractive tools to hedge against customer migration and other forms of load fluctuations. According to option pricing theory, options are not any more useful for hedging price risk than are forward contracts unless one is exposed to other risks that correlate with and enhance price risk, for example, loss of load accompanied with declining prices. The IPA states that in theory, option prices are determined by the value of the option as a price hedge. If an option had additional value as a hedge against load migration risk, the IPA says some might consider options to be a bargain. According to the IPA, it turns out that options are expensive when used as hedges for load migration risk. The IPA claims this is because if a call option on 1 MW of load has a price V, then that should be its value as a price hedge. If the 1 MW is not currently served by the utility, but may return with some probability P, then the value of this option should be only P times V which is less than its price. In other words, the value of the option as a hedge against load migration risk is less than its value as a price hedge, but it is the value as a price hedge that determines the option's price.

The IPA claims there are also other costs and logistical obstacles to using options.

- A large part of the volume of options on the market is traded on exchanges. They have a particular advantage in that the trading exchange bears the counterparty default risk. However, the IPA's structured procurement process prevents the IPA from buying options on the exchanges.

- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased by the IPA required an affirmative exercise decision, which most likely they would, the utilities would seek regulatory comfort on their exercise decision-making before agreeing to use options. For example, if an exercise decision were dependent on the utility's load forecast or view of municipal aggregation, the utility would want to be able to show it had acted prudently. If the utility exercised a put option, to sell the underlying hedge, it would want to be sure that decision did not make it a wholesale market participant for purposes of FERC Order 717. If the option exercise were purely financial and automatic-resulted only in a cash payment from the option holder - these concerns might not be as important, but counterparty credit would be an issue.

- The use of options is subject to regulations under the Dodd-Frank Act of 2010 (specifically Title VII). Under this act, the trading of options (and other swaps) would be reported to a central database for clearing purposes. Trade details (price, volumes, time stamped trade confirmations, and complete audit trails) would need to be reported. In addition, trade records must be kept for 5 years after the termination of trade (either through exercise or expiration), and must be

made available within five business days of request. This would add to either the purchase cost or the ownership cost of options.

The PUA specifies that the Procurement Plan “shall include … the criteria for portfolio re-balancing in the event of significant shifts in load.” In the IPA's view, it is 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.

1. To date, 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.

2. Sales of excess supply by the utilities in the wholesale market to rebalance their supply portfolio may create a de facto "wholesale marketing function" within the utilities. The employees involved in wholesale marketing activities would be subject to the separation of functions in accordance to FERC Order 717.

3. For the last few years, the utilities have scheduled excess supply in their portfolios, or made up supply deficits, in the RTOs' day-ahead markets. This has been the dominant mode of portfolio rebalancing.

4. As an alternative form of rebalancing, the IPA could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that has the authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2) to sell excess supply.

5. The IPA could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a "marketing function." The IPA does not envision entering into derivative contracts for rebalancing purposes.

6. The IPA could conduct more than one procurement event in a year if the rebalancing required is to increase the supply under contract. This is what the IPA proposed for 2014 (and again proposes in this Plan) and it conducted a second procurement event on September 22, 2014. The volumes for that procurement were updated based upon load forecasts supplied by the utilities in July 2014 and reflect increased volumes to be procured compared to the March 2014 forecasts.

The IPA indicates that the Purchased Electricity Adjustment ("PEA") functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked, and the PEA adjusted, for each customer group.

According to the IPA, the PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from the estimate—in other words, the impact of risk. The IPA says while Ameren's PEAs have been generally negative, ComEd's have been more often than not positive, and have had more volatility. The IPA notes ComEd has voluntarily limited its PEA to move between +0.5 cents/kilowatt-hour ("kWh") and -0.5 cents/kWh, and ComEd's PEA has oscillated between those limits.

The IPA reports that in April 2014, the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals associated with the computation of the PEA each June to be rolled into the base default service rate for the next year and the associated balance to be reset to zero. To additionally reduce PEA volatility, the IPA says ComEd is investigating "unbundling" ComEd's supply charge into energy, capacity, and transmission charges.

In July 2014, the IPA says the value of Ameren PEAs decreased significantly. The IPA understands this decrease is likely the result of Ameren over-collection during the past winter and its PEAs represented the return of these proceeds to customers.

According to the IPA, the current IPA hedging strategy, including the planned September procurements for ComEd and Ameren, combined with ComEd's implemented and under consideration improvements to its PEA methodology, should result in reduced volatility in the PEA for the coming years. The IPA claims this reduction in PEA variation will provide the clarity that many ARES have sought by allowing for an easier comparison between the utility rate and potential offers by ARES.

The IPA states that the utilities, pursuant to plans developed by the IPA, have historically used fixed-price, fixed-quantity forward energy contracts and financial hedges (such as the LTPPAs), along with RTO load balancing services to serve load. In other words, energy delivery has been coordinated by the RTOs and the IPA has arranged a portfolio of long-term contracts and standard forward hedges, in multiples of 50 MW (and in 2014, 25 MW), for each utility. Ancillary services have been purchased from the RTO spot markets. The utilities have used Auction Revenue Rights to mitigate transmission congestion cost.

The IPA indicates forward hedges have been procured on a "laddered" basis. The IPA originally sought to hedge 35% of energy requirements on a three-year-ahead basis, another 35% on a two-year-ahead basis, and the remainder on a year-ahead

basis. Prior to 2014, procurements had been annual, in April or May, rather than on a more frequent or ratable basis. For example, in the spring of 2010, the IPA procured forward hedge volumes (in 50 MW increments) as close as possible to 35% of the monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the Spring of 2011, the IPA indicates it procured forward hedge volumes (in 50 MW increments) to bring the total volume as close as possible to 70% of then-current monthly average peak and off-peak load forecasts for the 2012-2013 delivery year and in the Spring of 2012, the IPA procured forward hedge volumes (in 50 MW increments) to bring the total volume as close as possible to 100% of then-current monthly average peak and off-peak load forecasts for the 2012-2013 delivery year. In the 2013 Procurement Plan, the IPA says it indicated it was considering a change in hedging from 100%/70%/35% of the expected load to 75%/50%/25%. There were no procurements in 2013 so that hedging strategy was not formally adopted or implemented.

In the 2014 Procurement Plan, the IPA proposed a modification to the 75%/50%/25% strategy. The IPA suggested that the procurement goal for a mid-April procurement event should be to hedge 106% of the expected load forecast for June-October. These months would be close to the procurement date and no benefit was seen in deferring 25% of the procurement to the spot market. On the other hand, because of the correlation between load and price and because prices in the hours of high usage are more than 100% of the time-weighted average price, the IPA says a $1/megawatt-hour ("MWh") movement in the monthly average price translates into an increase of more than $1/MWh in the average portfolio cost (the load-weighted average price) – in fact, approximately $1.06. The IPA continued to recommend hedging up to only 75% of the expected load for November-May of the prompt delivery year in the April procurement, but also recommended a second procurement in September to bring the hedged volume to 100%.

The IPA claims the procurement schedule balances procurement overhead costs, price risk, and load uncertainty. If the amounts to be hedged in any year are small, the IPA says it could decide to avoid the procurement overhead and not schedule a procurement event (as in 2013). The IPA has not used options, unit specific contracts (except for the LTPPAs and the FutureGen agreement), or other forms of hedging in the past. In addition, the IPA has not used forward sales or put options to rebalance its portfolio.

The IPA claims most risks in power procurement have been mitigated by its historic procurement strategy. In the 2014 Procurement Plan, the IPA described its use of a Monte Carlo model to evaluate the potential cost and uncertainty impacts of various risks. The IPA also used this model to estimate the added cost of full requirements contracts.

The IPA says the risk study in the 2014 Procurement Plan led to a change in procurement strategy motivated by shaping risk. The IPA states shaping represents the impact of the correlation of load and price, both of which vary during the period of time

hedged by a standard product. According to the IPA, shaping risk magnifies price exposure and it is desirable to reduce such risk. In fact, the IPA hedges the July through October position to 106% of expected average load. For this Plan the IPA recommends a further refinement of this strategy by limiting the 106% hedge level to the July and August peak periods, these are the periods of highest price and load volatility.

The IPA asserts that the "polar vortex" event of 2014 demonstrated that, in rare events, that there can be unexpected levels of price risk in the winter, and that price excursions can have short-term causes that cannot be accounted for when hedging several years ahead using load forecasts that generally assume normal weather. The IPA says in the case of ComEd, that over the last ten years, price peaked (moderately) in the summer, and rose again (though not as high) in the winter. The IPA says the classic price pattern of a summer peak occurred in 2008-2009. The IPA also says a year in which a summer peak and a secondary, shorter-lived winter peak occurred in 2005-2006. The IPA adds that the last year, 2013-2014, had a pronounced winter price peak, whose effects also subsided.

According to the IPA, the 2014 price peak was exacerbated by the correlation of load and price, i.e., shaping. The IPA states that the January 2014 price was enhanced by the price shape much more noticeably than was the December 2006 peak. The IPA suggests this recent experience supports the IPA's strategy to be hedged to no less than 100 percent of expected average load during the winter months.

The IPA reports that the current supply portfolios of Ameren and ComEd are based on the strategy of procuring blocks of energy to meet expected monthly average load forecast and balancing actual load in the day ahead and real-time markets. The IPA claims this strategy does not perfectly hedge their load. The IPA says this is primarily due to load uncertainty, the mismatch of demand and hedge profiles, and the correlation between price and load. Eligible retail customers are exposed to residual risk resulting from the utilities' portfolio design through the monthly Purchased Electricity Adjustment. The IPA believes that its procurement design, and the recent and proposed modifications to the PEA adequately control that risk. The IPA indicates ComEd further mitigates this impact by voluntarily limiting the PEA to ±0.5 cents per kWh each month.

The IPA states that on the other hand, if the goal of the supply strategy/portfolio design were to provide power to eligible retail customers at a fixed price over a multi-month period (one to three years), similar to most ARES products offered either directly or through municipal aggregation, then a full requirements procurement approach might be a reasonable alternative that could achieve that result. The IPA says the full requirements supplier commits to serve a portion (a percentage) of the load for every hour at a set price per MWh. Those portions, commonly called "tranches", will increase or decrease in absolute volume depending on factors such as customer switching, weather, and economic activity. The IPA says the actual amount of power a supplier would need to provide in a given hour would not be predetermined, but rather would represent a risk that the supplier would need to manage within the set contract

price. Full requirements contracts provide a form of insurance to customers by outsourcing supply risk to a third party to manage.

The IPA says the 2014 Procurement Plan provided some guidance into the price premium (or "residual compensation") one could expect to pay for price insurance, as well as the effectiveness of that insurance in removing price uncertainty, using a bottom-up Monte Carlo simulation model to estimate future market prices. The 2014 Plan attempted to facilitate discussion as to whether customers would perceive the insurance as valuable enough to justify the premium.

The IPA was created, in part, 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." In reviewing and approving the IPA's proposed procurement plan, the IPA claims the same standard applies. For like products, this language envisions balancing price and volatility, with the IPA says it and Commission are tasked with striking an appropriate balance on customers' behalf.

In the IPA's view, the choice to buy full requirements should not depend on the magnitude of the full requirements price (assuming it is greater than the price expected from another procurement strategy), but rather on whether the price is justified by the added value that customers would perceive they obtain by eliminating the uncertainty around the price an evaluation that includes a subjective exercise of balancing competing considerations. The IPA says there is no obvious formula for converting forward-looking statistics of the cost distributions into dollar measures of value, which depends on customers' risk preferences and other factors. The IPA believes an informed utility supply customer who values absolute price certainty could demonstrate that valuation by choosing to take service from an ARES who offers a fixed price directly or through a comparable municipal aggregation plan.

In June 2014 the IPA held a workshop with interested parties to consider the appropriateness of a full requirements portfolio. Following the workshop the IPA issued a Request for Comments ("RFC") and posted the RFC on its website.

According to the IPA, the discussion at the workshop, and the responses to the questions, did not reveal a consensus or even majority opinion on most questions. Ameren and ComEd raised a variety of practical implementation concerns and were concerned that the effect of existing hedge portfolios be taken into account when estimating the risk reduction impact of full requirements contracts' risk reduction impact. The IPA says while ICEA and RESA generally supported the notion of full requirements being a bundled product (e.g., including ancillary services and RECs in addition to energy), they clarified that given ComEd's recent consideration of unbundling capacity for eligible customers, they favor excluding capacity and network transmission service from a full requirements product in Illinois. ICEA and ComEd expressed differing views as to whether ComEd's PEA charges have been primarily driven by rate design (the bundling of capacity charges) or supply portfolio design. The IPA says most

commenters withheld judgment on whether the value of price insurance justified its cost, although CUB clearly believed that it did not. Based on the comments received and the IPA's knowledge of the Illinois retail market, the IPA feels that there is no clear evidence that, as a class, retail customers who chose to take bundled service from the utilities desire to pay a premium to mitigate the residual price fluctuations associated with the current procurement strategy.

In the Plan, the IPA discusses the experience with full requirements products in other jurisdictions. The IPA also discusses the risk premia analysis it performed in the 2014 Plan. Using market data from New Jersey, the IPA estimates the premia for price insurance associated with full requirements products. The IPA concludes that there is evidence that full requirements contract prices include a price insurance premium of several dollars per MWh.

After determining the likely range of price premiums, the IPA says it turned its attention to the potential benefits of full requirements. The IPA believes the benefits of full requirements products cannot be rigorously quantified. According to the IPA, these benefits are subjective viewpoints about perceived value that lend themselves better to a policy analysis rather than a cost benefit analysis. The IPA insists a pure cost benefit analysis is simply not possible because the costs can only be reduced to a range, and the benefits are not numerical. With those limitations, the IPA argues it is not possible to reduce the argument to a comparison of the cost/benefit ratio of two differing procurement approaches.

The IPA states that in working to present a more thorough and accurate analysis of full requirements procurement, it was very mindful of stakeholder comments encouraging the use of actual market data on full requirements pricing. The IPA also sought to minimize the use of models of price and load fluctuations. The IPA says such models can always be questioned and, especially in the case of models of customer migration, are supported by rather short historical records.

For its analysis, the IPA analyzed auction results from the state that has been conducting full requirements solicitations for the longest period: New Jersey. To conduct this analysis, the IPA developed an estimate to account for the non-energy components of full requirements service, relying only on observable market data. The IPA's analysis takes advantage of the existence in New Jersey of two different full requirements products, priced differently. The IPA says both full requirements products provided by suppliers in New Jersey are defined to consist of "unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service, including all losses and/or congestion costs associated with the provision of such services, and such other services or products that a Supplier may be required, by PJM or other governmental body having jurisdiction, to provide in order to meet the Supplier Responsibility Share under this Agreement."

The IPA states that Basic Generation Service – Commercial and Industrial Pricing ("BGS-CIEP") suppliers in New Jersey are paid the auction price (per MW of

capacity requirement), plus the cost of network transmission service, plus the load-weighted PJM spot price for energy, plus $6/MWh. This produces a tariffed price that fluctuates with the wholesale cost of energy. The IPA states that Basic Generation Service – Fixed Price ("BGS-FP") suppliers provide the same product as do BGS-CIEP suppliers (unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service), but at a fixed price under three-year contracts. The IPA claims the price of BGS-FP supply should equal the expected price of BGS-CIEP service, plus a premium (or residual compensation) for price insurance.

The IPA says all these values needed to calculate the price insurance premium are directly available from the New Jersey auction results, except the expected PJM spot price, which it says can be approximated by using the energy futures price as of the BGS auction, adjusted for the historic relationship between load-weighted and average prices.

The IPA claims the table reproduced below provides evidence that full requirements contract prices typically include a price insurance premium of several dollars per MWh. The IPA suggests the difference between the results for Public Service and Gas Company ("PSE&G") and Jersey Central Power and Light Company ("JCP&L") may be associated with the ongoing increased in PSE&G transmission rates.

Premium for Price Insurance Derived from New Jersey Auction Data

	PSE&G			JCP&L		
	2009-2012	2010-2013	2011-2014	2009-2012	2010-2013	2011-2014
BGS-FP price ($/MWh)	103.72	95.77	94.30	103.51	95.17	92.56
- Expected spot price	-76.00	-62.85	-56.25	-73.12	-60.70	-54.28
- Ancillary Service Price	-6.00	-6.00	-6.00	-6.00	-6.00	-6.00
- OATT rate	-6.01	-7.58	-10.33	-4.45	-4.62	-4.85
- BGS-CIEP price	-17.56	-15.23	-19.45	-19.65	-16.70	-20.76
Estimated premium ($/MWh)	-1.84	4.11	2.27	0.29	7.15	6.67
Estimated premium (% of expected spot)	-2.4%	6.5%	4.0%	0.4%	11.8%	12.3%

The IPA states that the NorthBridge Report that was attached to ICEA's objections to the 2014 Procurement Plan contained an analysis based in part on information from a Pennsylvania regulatory proceeding in 2012. The IPA notes there was a subsequent analysis by NorthBridge that formed the basis for testimony in a 2014 proceeding before the Pennsylvania Public Utilities Commission. The IPA says that study reviewed results from past PECO full requirements procurements. According to the IPA, the testimony of Scott Fisher of NorthBridge includes an analysis of the specific cost components of those prior PECO procurements, and defines residual compensation as what is "required by suppliers to cover the other costs and risks that [the expert witness] did not individually quantify." The IPA says from a customer's point

of view, “residual compensation” is equivalent to a price premium because it is a cost the customer would not otherwise pay. The IPA asserts that the residual compensation levels from that testimony are additional costs of several dollars per MWh for full requirements service, which it says are in line with the other estimates the IPA has made.

The IPA finds of particular note, the increase in residual compensation in the January 2014 procurement. The IPA states that the testimony from NorthBridge’s expert witness notes that this procurement was coincident with the price increases associated with the so-called polar vortex. Given that testimony, the IPA suggests it is possible that the weather events of early 2014 indicated to suppliers that they had been underestimating, and hence underpricing, their commitments. The IPA further suggests that if so, previously observed premiums may be conservative estimates of future residual compensation.

The IPA says it understands that under certain adverse cases, the actual cost of a block hedging strategy could be greater than the cost of a full requirements strategy. The IPA believes extreme adverse outcomes are correspondingly unlikely but asserts protecting against such extreme outcomes may be the most compelling reason to consider implementing a full requirements procurement. However, the IPA insists its current hedging strategy has been carefully designed to provide a reasonable level of insurance against price spikes (at a lower expected cost than the full requirements alternative), given that the entire expected load will be covered by fixed-price hedges.

According to the IPA, one adverse case that could concern would be if there were a large volume of price-induced customer migration. Currently, the IPA says high migration volumes would most likely be associated with the expiration of municipal aggregation contracts and return of those customers to bundled service after the IPA’s procurement volumes are set. The IPA says to mitigate the risk of such an adverse case, it monitors the energy markets regularly to understand the factors that drive customer behavior (for example – price, product, regulations, the environment, etc.) and to anticipate and mitigate such potential return to service. The IPA has also recommended a hedging strategy that it believes mitigates load migration risk. The IPA says the implementation of the fall procurement event is the direct result of the need to mitigate the risk of load migration associated with the expiration of large municipal aggregation contracts.

The IPA states that just as adverse outcomes can increase ratepayer costs, supportive outcomes can reduce them. The IPA suggests an example would be the large PEA credit Ameren eligible retail customers have been receiving in recent months. The IPA says this credit has been driven in large part by Ameren settling its long energy positions last winter in the hourly market at a profit which is then returned to eligible retail customers. Under full requirements service, the IPA suggests customers would not receive the price reduction benefits of likely favorable cases. The IPA claims the nature of an expected cost premium is that in most scenarios, customers pay more.

The IPA notes the Commission requested that the IPA report on "any significant implementation costs it believes will result from this shift in procurement strategy." In addition to the expected case premiums, the IPA claims implementing a full requirements procurement would have additional costs and issues. An estimate by the IPA's Procurement Administrator is that the initial set up of a full requirements procurement would be $850,000. If the procurement were for just one utility, the IPA says the cost estimate would be reduced by 25-30%. The IPA notes this is only an estimate because it depends on some specific features of the full requirements procurement, such as the nature of the services that would be provided by the full requirements supplier besides load following energy and whether the full requirements procurement would be conducted as a single procurement event for both utilities. The IPA says a full requirements procurement would require in particular the development of contract and credit forms tailored to the product; the compilation of data with the assistance of the utilities sufficient for bidders to evaluate the opportunity; the response to bidder questions that may include inquiries about PJM and MISO developments such as the current changes to the PJM capacity construct. The IPA suggests the development of sufficient data, which would be necessary to keep premiums to a minimum, may be particularly challenging. The IPA believes suppliers would likely seek to evaluate the potential for migration, which would involve providing various data, including data on municipal aggregation and information on how rates for eligible retail customers are determined on the basis of the utility's entire supply portfolio. The IPA is also concerned that in the current fiscal year (which runs through June 30, 2015) it would not have sufficient funds appropriated by the General Assembly to allow it to support these activities, should the Commission order it to implement a full requirements procurement during the fiscal year. While the cost of procurement administration is recovered from bidders and suppliers, the IPA says its expenditures for procurement administration must fall within the total amount appropriated for the fiscal year by the General Assembly for the IPA's Operation Fund.

The IPA maintains that full requirements procurement carries a price premium, and provides an estimated range of potential premia based on both empirical data and modeling. In return for its higher price, the IPA says full requirements service provides customers the benefit of increased price stability. In determining whether to propose full requirements procurement, the IPA claims confronted the following question: what is the customer appetite to pay higher prices for increased stability?

The IPA states that one instructive recent survey came from a report on retail markets in Alberta, Canada. The IPA says while half of customers indicated they wanted a fixed price for the year, only 13% were willing to pay a premium for that certainty. On the other hand, half of customers were interested in seeking the lowest price.

The IPA believes that customers have varying degrees of interest in that protection. Without strong majorities seeking that protection, the IPA does not believe these surveys provide support for increased costs to ensure some price protection via full requirements procurement. The IPA also indicates it is not aware of any significant

level of customer dissatisfaction in the ComEd service territory with the current and proposed IPA procurement approach that results in having rates that can fluctuate slightly month-to-month due to the Purchased Electricity Adjustment. The IPA presumes that the fairly consistent and sizable PEA credits in the Ameren service territory are even less likely to spur customer complaints because they result in savings for eligible retail customers. The IPA contends that while the lack of consumer outcry does not in itself validate the IPA's procurement approach, it does not support a policy goal to provide full price insurance at a cost premium either.

The IPA acknowledges that the current procurement strategy can lead to fluctuations in the PEA. The IPA expects the volatility of the PEAs for ComEd and Ameren to decline as a result of various improvements to the IPA procurement design (and for ComEd customers, ComEd's improvement to its PEA). The IPA says the mere existence of the PEA (and its month to month fluctuation) makes it slightly more difficult to compare the utility rate to an offer from an ARES, but the IPA does not believe that adding costs to the price paid by eligible retail customers to ease comparison shopping by customers who have left utility service is an appropriate policy goal for it to pursue under its mandates in the IPA Act.

The IPA says it has refined its block procurement approach over time, most significantly by adopting a new hedging strategy in the 2014 Plan (continued into the current Plan) that includes smaller block sizes and a second procurement in the fall. The IPA claims this approach was adopted to address the greatest risk to the portfolio, return of load. IPA notes ComEd has made improvements to its PEA methodology such as capping the PEA volatility, the annual resetting of the balance, and the proposed unbundling of capacity from energy that will further reduce PEA volatility. The IPA believes its block procurement approach successfully meets the mandate of the IPA Act to, "[d]evelop 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" and does not need to be changed to a full requirements approach.

Although many other states with retail competition conduct full requirements procurements, the IPA does not believe this alone is a compelling reason to change course. The IPA notes not one of those states has a procurement process comparable to Illinois. The IPA was specifically created by the General Assembly to operate in a structurally insulated, independent, and transparent fashion so that nothing impedes the IPA's mission to secure power at the best prices the market will bear, provided that the IPA meets all applicable legal requirements. The IPA suggests it may be the case in other states that the procurement design was instituted so that utilities did not have to make procurement decisions whose prudence would be reviewed and possibly challenged and no agency like the IPA was available. The IPA says in some states the default service is more of a "provider of last resort" service, one that is available to only ensure that customers have a rate to fall back on in case of default by a retail supplier. In contrast, the IPA Act instructs the IPA to actively manage the procurement process to benefit the eligible retail customers with an attractive rate option.

The IPA notes that in comments on the IPA's draft 2015 Procurement Plan, ICEA proposed a four-year pilot program for ComEd eligible retail customers to test the idea of full requirements procurement in Illinois. The IPA does not recommend conducting this pilot and does not include the proposed pilot in the Plan. The IPA maintains it has a statutory mandate to "[c]ontinue to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time, in accordance with applicable law." In reviewing the extensive analysis above regarding the costs and benefits of full requirements procurement, including the actual and modeled price premiums associated with full requirements procurement across multiple states, the IPA believes that its 2015 Procurement Plan's block purchase approach achieves that goal.

The IPA appreciates that there may be desire by some parties to have more information about full requirements procurement that cannot be captured by studying those states or by conducting additional simulations of rate impacts (and, in particular, experience specific to Illinois). According to the IPA, a pilot program that covers only a fraction of the load of ComEd's eligible retail customers, to be blended with other supplies, will not provide any customers with price stability, although it may reduce variability, and will not provide any insight as to whether eligible retail customers, as a class, are willing to pay for price stability. The IPA believes that the authority granted to it in the IPA Act and the PUA to develop and implement procurement plans for eligible retail customers does not call for this sort of experimentation. The IPA suggests that while a pilot program may provide new data, it believes it would fail to provide "the lowest total cost over time, taking into account any benefits of price stability," and thus should not be approved.

The IPA states that demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized expected case peak load, on days when the weather is hotter than normal. The IPA says demand response programs do not affect the weather-normalized load forecast. The IPA asserts the programs are supply risk management tools available to help assure that sufficient resources are available under extreme conditions. PJM has a functional capacity market that includes dispatchable demand response as a resource. To the extent that demand response programs receive "capacity credit", the IPA says PJM pays for this capacity based on the price from the capacity auctions and the proceeds are primarily used to fund payments to the responding customers.

In the case of Ameren, the IPA says MISO provides the ability for demand response measures to contribute to reducing supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat demand response ("DR") and energy efficiency ("EE") resources similarly to other capacity providing resources for operational planning purposes. The IPA notes MISO Module E permits LSEs to net the effects of DR and EE resources from their coincidental peak and will credit these resources with the equivalent number of Zonal Resource Credits ("ZRCs").

The PJM and MISO capacity markets are FERC jurisdictional, governed by tariffs filed with and approved by FERC. The IPA reports that in May, the U.S. Court of Appeals for the District of Columbia Circuit vacated a FERC order related to the appropriate compensation for demand response, Order No. 745, "[b]ecause FERC's rule entails direct regulation of the retail market - a matter exclusively within state control." The IPA suggests this decision could lead to a more comprehensive challenge to ISO-supplied demand response compensation. In the future, the IPA says it may not be possible to simply rely on ISO capacity payments to compensate demand response providers. The IPA believes the role of states and state agencies in compensating demand response may become much more important. As this issue is resolved in the courts, the IPA says it will revisit it in future procurement plans as necessary.

D. 2015 Procurement Plan Resource Choices

The primary resources included in the 2015 Procurement Plan for the forecast horizon include: (1) energy efficiency as a supply resource; (2) incremental energy efficiency; (3) energy procurement strategy; (4) balancing recommendations; and (5) demand response.

1. Energy Efficiency as a Supply Resource ("EEAASR")

The IPA indicates that in its draft 2014 Procurement Plan, the IPA raised the idea of procuring energy efficiency as a supply resource, separate from its Section 16-111.5B procurement, and invited comments from stakeholders for additional feedback. The IPA's rationale for the proposal was: rather than viewing energy efficiency simply as reducing forecast load, demand-side resources could potentially constitute a lower-cost alternative than comparable supply at times when prices are highest or load is greatest. If less-expensive demand-side resources could be procured in lieu of conventional supply during periods of high cost or high load, the IPA claims it could be better-positioned to meet its statutory objective of developing "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."

The IPA says while logically sound, the details of the approach proved complex. Upon receiving feedback on its draft 2014 Procurement Plan, the IPA determined that the idea lacked the detail and clarity necessary to transition from an alluring thought exercise to a concrete procurement strategy. Although still intrigued by the potential benefits, the IPA did not include the procurement of energy efficiency as a supply resource in its filed 2014 Procurement Plan.

The IPA indicates the concept was tabled for further discussion in the 2014 Procurement Plan. Still, the IPA remained interested in its potential benefits and held a workshop on June 18, 2014 to receive continued feedback. Following that workshop, the IPA circulated a set of questions to workshop participants. Received responses were posted on the IPA's website.

The IPA reports that as expected, views were divergent. Some parties believed the IPA lacked statutory authority to conduct such a procurement event, believing that demand-side resources were not “standard wholesale products” and that Section 16-111.5B set forth the exclusive pathway for including energy efficiency in the IPA’s Procurement Plan. Others believed that while segmenting out more expensive energy procurement blocks was sensible, competition should be between both demand-side and supply-side resources. Still others believed that the issue was ripe for inclusion and suggested a Spring 2015 procurement for the delivery of resources beginning in Fall 2015.

After feedback and further consideration, the IPA indicates it has settled on the following key principles to guide an Energy Efficiency as a Supply Resource (“EEAASR”) procurement:

First, any EEAASR procurement should be structured to provide lower expected total customer costs than a comparable supply-side procurement. Although the Commission has interpreted “lowest total cost over time” as referring to the IPA’s entire Plan while stressing the value of portfolio diversity, energy efficiency also participates as a Section 16-111.5B resource, allowing for some of its benefits to be already captured. For energy efficiency to displace blocks of supply in standard energy procurement, the IPA believes an EEAASR procurement should feature a lower expected total cost to ratepayers, inclusive of administrative costs, than what would be accomplished through its block supply procurement.

Second, an EEAASR procurement should be focused on pre-designated “super-peak” blocks. Although procuring demand-side resources responsive to high price or load may have advantages, the IPA suggests these approaches offer administrative complexities (such as active management through an operator) that the IPA is not currently equipped to manage or assign. The IPA says segregating out expected highest-use blocks in advance and conducting a “super-peak” EEAASR procurement for those blocks offers a clear, consistent approach that enhances delivery certainty and fits squarely within the IPA's established procurement processes and expertise.

Third, the products procured in an EEAASR procurement should be resources on the customer side of the meter. The IPA envisions that in future procurements demand-side and supply-side resources could compete on level terms, but believes that procurement structure and administrative ease is best served by procuring customer-side products exclusively in its initial EEAASR procurement.

Fourth, the size of the individual blocks to be procured should be small enough to allow for small scale load reductions to compete. The IPA suggests that whether such programs feature compelling-enough economics will be determined through a competitive procurement process, and the IPA should ensure that procurement block size is not so large as to exclude otherwise cost-effective load reductions.

Fifth, contracts should be for a length greater than only one year. Given the potential administrative costs of an EEAASR procurement, and the operational costs for resource-providers, the IPA believes multi-year delivery contracts feature far more compelling economics, significantly increasing the likelihood of a “least cost” procurement compared to supply side options. The IPA claims multi-year contracts also provide more value and certainty to the end users who produce the underlying reductions.

Sixth, caution must be taken to ensure against non-delivery. The IPA says it recognizes that eligible retail customer interests are only furthered to the extent that lower-cost resources are actually delivered. Should non-delivery occur, the IPA says replacement super-peak supply would have to be procured on the spot market at a potentially greater cost. Therefore, the IPA indicates it would need strong credit requirements and non-delivery penalties, perhaps mirroring those for conventional supply contracts. The IPA believes failure to deliver the resource by a supplier should not create additional costs for eligible retail customers.

Seventh, EEAASR resources may be procured from customers throughout each utility’s service territory (not merely “eligible retail customers” but also from competitive-class customers).

The IPA proposes a procurement event for energy efficiency as a supply resource with the following characteristics:

- **Super-Peak Blocks Using on Pre-Scheduled Dates/Times**: The IPA proposes procuring a demand-side product delivered during the hours of 3 p.m. to 7 p.m. central standard time ("CST") on summer non-NERC holiday weekdays (e.g., 4-hour blocks for 5 days a week-other than July 4th if it falls on a weekday-for the period running from June 1 through August 30). This equates to approximately 260 hours per delivery year. To the extent load reductions during the super-peak time result in load shifting to other times, the cost impact of the load reductions should net out the expected increased costs incurred by eligible retail customers at those other times.

- **Multi-Year Contracts**: The IPA proposes to procure 3-year delivery contracts of EEAASR products. The IPA believes that this contract length best mitigates administrative costs and supplier overhead, while capping contract length in a manner consistent with the IPA's scheduled block procurement of supply.

- **100 kilowatt ("kW") blocks**: The IPA proposes to procure 100 kW demand-side resource blocks. The IPA believes that this block size should be small enough to allow for broad participation and appropriately accommodating of small programs. The IPA notes that large load-reduction programs can purchase multiple blocks, and all load-reduction programs may aggregate to purchase individual or multiple 100 kW blocks. To ensure that procurement volumes

remain consistent with other energy supply resources procured by the IPA, the Agency proposes to measure blocks by average kW over the block period.

- **Late 2015 Procurement; June 2016 Delivery**: As an EEAASR procurement will require new contracts and EEAASR suppliers will need ramp-up time to secure and develop resources, the IPA believes that conducting a Spring 2015 procurement or expecting Fall 2015 delivery decreases the likelihood of a successful procurement. By adopting a longer timeframe, the IPA will have time to work through administrative complexities and allow for the market to properly organize. This timeline will also allow for updating the March 2016 load forecasts to include the results of the EEAASR procurement in identifying the supply gap remaining to be filled in a Spring 2016 procurement.

- **Summer Procurement Only**: While arguments can be made for including a winter EEAASR product in this procurement, the periods (and magnitude) of high winter peak prices are generally less predictable than during the summer. The IPA would prefer to demonstrate the merits of an EEAASR procurement before pursuing what may be a more challenging model with a winter EEAASR procurement, and notes that a winter EEAASR procurement may be most effective if driven by triggered price or load thresholds.

- **Optionality:** The IPA is proposing a late 2015 Procurement for June 2016 delivery. If the IPA concludes that administrative costs may be too significant relative to volume likely to be procured that the market is not appropriately mature, or should some other reason or barrier emerges that causes the IPA to believe that an EEAASR procurement would not be in the best interests of customers, the Agency-in consultation with Commission Staff, the Procurement Administrator, and the Procurement Monitor would seek permission to make a formal request of the Commission to cancel the procurement no later than August 2015.

In addition to these characteristics, the IPA says there are several issues not yet resolved which should be determined prior to an EEAASR procurement. The following is a sampling of those issues:

- Vendor/Program Qualification
- Other Programs
- Product Definition
- Credit Requirements and Non-Delivery Penalties
- Verification

To the extent that open issues may remain, the IPA says it would be open to hosting workshops in Spring 2015 with an eye toward resolution of matters by Summer 2015 to prepare for a late 2015 procurement. The IPA understands the breadth and depth of issues still needing resolution, but is confident that the proposed procurement and delivery schedule allows sufficient time to accommodate them.

While the IPA believes it has the authority to conduct an EEAASR procurement and requests that the Commission consider approving that proposal, the IPA suggests an alternative approach should also be considered. The IPA says the goal of the EEAASR proposal is to lower the cost of power by focusing on offsetting the cost of power during high price summer hours. According to the IPA, another way to achieve this result – and one which may better-match the EEAASR proposal's goal – is by flattening the load shape of eligible retail customers. In this approach, the IPA says not only could the quantity of peak block procurement be reduced, but the match between procured peak blocks and the actual load shape would also be improved and shaping costs could be reduced.

The IPA proposes the alternative, and perhaps simpler, approach of mandating the modification of the Section 16-111.5B third-party RFP process to specifically seek out programs that would reduce demand during peak hours and provide additional incentives for those programs while remaining cost effective.

To approve this alternative approach, the IPA suggests Commission should require the utilities to modify their Section 16- 111.5B third-party RFPs in the following manner.

- Specifically include a request for proposals for targeted programs that could identify and demonstrate reductions during peak periods.
- Update the TRC test for these targeted programs to use a time-specific avoided energy cost that would account for the higher price of power that is offset. This would allow for greater flexibility in programs that could bid.
- Provide an additional financial incentive to these programs for demonstrated peak period kWh reductions. This additional incentive could take on the form of the difference between the estimated average energy cost and the estimated energy cost during peak periods.
- For the reasons described in the IPA's core EEAASR procurement principles, the IPA believes these bids should be for programs of at least three-years in duration.

The impact of this approach would manifest itself in a change to the hourly load profile of eligible retail customers, thus reducing procurement needs for times when price and load are highest.

2. Incremental Energy Efficiency

In approving the IPA's 2014 Procurement Plan, the Commission directed workshops to consider multiple unresolved issues pertaining to Section 16-111.5B incremental energy efficiency. The IPA says that the full Staff Report, including a full list of all questions addressed through the Section 16-111.5B workshop process and a complete roster of workshop participants, is attached as Appendix B-2 to the Plan. As the resolution of designated workshop issues provides the IPA with valuable guidance

in developing its annual procurement plan, the IPA thanks Staff for the time and resources it put into leading a very comprehensive and detailed process and thanks all other participants for their participation. While the IPA recognizes that parties reserve their right to modify their positions with respect to any of the consensus items and contest their adoption in comments and litigation, the IPA is satisfied with the consensus items and recommends that the Commission approve the consensus language. The IPA believes the Commission should approve the consensus language from the 2014 Staff-led workshops on Section 16-111.5B.

Ameren's submittal to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA includes seven appendices. Ameren's submittal includes identification of nine energy efficiency offerings for the 2015 Procurement Plan with a TRC of above 1.0 and which met the requirements of Ameren's RFP although, Ameren recommends inclusion of only one behavior modification program. The IPA says all of these programs passed the Total Resource Cost Test ("TRC") at the time of assessment.

Ameren Energy Efficiency Offerings

Program	Net Savings (MWh)		Total Utility Cost	TRC
	Program Year 1	Program Year 2		
Moderate Income Kits	1,567	1,567	$1,666,737	1.22
Residential Lighting	48,190	53,556	$21,637,240	1.64
Rural Efficiency Kit Distribution	7,876	7,876	$2,214,245	3.09
Multi-Family Major Measures	38,943	38,943	$32,820,805	1.57
Home Energy Reports	40,013	40,013	$4,555,440	1.12
Behavioral Energy Efficiency	47,111	47,111	$4,488,750	1.59
Small Business Direct Install	9,588	9,788	$7,174,723	1.19
Small Business Refrigeration	17,947	17,947	$7,571,125	1.09
Demand-Controlled Ventilation	5,318	-	$1,146,840	1.20

The IPA says the total net savings for these programs is estimated as 169,441 MWh at the busbar for the first program year and 169,689 MWh for the second program year, assuming the inclusion of the Home Energy Reports and not the Behavioral Energy Efficiency Program. The programs also contribute to a peak reduction of approximately 17.66 MW. The estimated savings attributable to eligible retail customers is 72,137 MWh for the first program year. The IPA believes that Ameren's submittal meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix B to the 2015 Plan, subject to a decision being made between the duplicative behavioral programs, should be approved pursuant to Section 16-111.5B(a)(5).

As part of its bid review process, Ameren provided the Department of Commerce and Economic Opportunity ("DCEO") with all bids that had a positive TRC for a review of whether any proposals may be duplicative of DCEO's program offerings. Among the

proposals received by Ameren was a Small Business Direct Install - Demand Control Ventilation program. DCEO believes this program is "duplicative."

Based on the information available to the IPA, it believes that this proposal may safely co-exist with DCEO's current program offering. The IPA says although the two programs may be similar in effect, the IPA understands the two programs to target distinct segments of customers – with DCEO focused on public facilities, and the third-party proposal focused on non-public small businesses. The IPA therefore recommends approval of the Small Business Direct Install – Demand Control Ventilation proposal.

The IPA reports that Ameren's submittal contained two behavioral modification program proposals - Home Energy Reports and Behavioral Energy Efficiency - determined by Ameren to be "duplicative" of each other. Ameren makes no express recommendation to the IPA on which program to recommend for adoption, and requests that "the IPA determine which Behavior Modification program to award the bid for PY8 and PY9."

The IPA believes that it has two roles in this situation. The first is to determine whether these programs are "competing" or "duplicative" using the seven-factor inquiry. If the two are not "duplicative," then each may be included and no recommendation need be made between the two. Ameren previously determined that only one program should be adopted because "the total number of residential customers eligible for the program could not support two behavior modification programs" and "running multiple programs would lead to significant confusion of residential customers, which would hamper the adoption of the Behavioral Modification program, rather than increase it."

After a review of each proposal, the IPA agrees with Ameren that these two proposals are "duplicative" and that only one should be approved. Each program targets residential customers using a similar delivery mechanism (engaging customers through energy reports, an online web portal, etc.) with the aim of using rich, relevant data to effectuate behavioral change, thus driving delivered savings. While there are nuanced differences between the programs, the IPA is confident that implementation of both programs would be both confusing and counterproductive, with savings from one program cannibalizing the other.

Having determined that only one proposal should be adopted, and noting that each proposal met RFP requirements and passes the TRC, the IPA says its second role is determining which proposal to recommend for inclusion. Here, the IPA indicates it has less guidance from either the PUA or past Commission Orders. As a threshold matter, the IPA has no clear criteria to apply in choosing between competing programs; its role under Section 16-111.5B is to review and verify assumptions about cost-effectiveness and program compatibility, and not to make normative determinations about relative program quality. In this particular instance, the IPA notes that both programs originate from well-established vendors - criteria that the IPA would otherwise like to use in making a recommendation.

The IPA states while the Home Energy Reports proposal is for 14% more households, the Behavioral Energy Efficiency proposal features roughly 17% greater estimated expected savings. The IPA says the Behavioral Energy Efficiency program has been higher calculated TRC than the Home Energy Reports, but the IPA has identified issues related to the reliability of these TRC calculations. For instance, the Behavioral Energy Efficiency program bid estimates electric savings per household that are over 30% higher than the Home Energy Reports and gas savings that are nearly 100% higher. The IPA believes the savings estimates for both programs were provided by the vendors because their proposed measures are not included in the Illinois Technical Reference Manual. The Home Energy Reports have been the subject of more than 20 evaluations across the country while the Behavioral Energy Efficiency program appears to use assumptions based on just one other program (with no clear citation to verified third-party evaluation). The IPA suggests this may lead to a significant degree of variation of certainty regarding the estimated gas and electric savings from these proposed programs. The IPA notes that if the savings estimates were adjusted to be comparable between the two programs, then the Home Energy Report program would have greater total savings and a slightly higher TRC than the Behavioral Energy Efficiency Program. In reviewing the program descriptions contained in the bids, the IPA does not see compelling evidence that the difference in savings per household between the Behavioral Energy Efficiency program and the Home Energy Reports would be as significant as indicated in the respective bids. Therefore the IPA concludes the variation in TRC values does not provide insight into which program should be approved.

Compelled to make a recommendation, the IPA believes that the Home Energy Reports program team's experience to date in Ameren's service territory and established working relationship with the utility makes it slightly more likely to deliver increased savings to customers and maximize the impact of Section 16-111.5B funds. The IPA thus recommends the Home Energy Reports behavioral program for inclusion in its Procurement Plan. Should Ameren fail to reach a contractual agreement with the vendor of the Home Energy Reports, the IPA recommends that Ameren be pre-authorized to enter into negotiations with the vendor of the Behavioral Energy Efficiency program.

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

- "AIC formally requests in this submission that annual updates to the measure values in the TRM and NTG ratio values result in changes to the implementer's savings goals and/or the cost structures between AIC and the implementer and will be re-negotiated for the savings calculations based upon the annual IL-TRM [Illinois Technical Reference Manual] and NTG updates for one program year' and further that programs resulting in multi-years (PY8 and PY9) will be re-negotiated annually to reflect the annual `deemed' IL-TRM measure values and NTG ratio values."

- “In the event that ICC does not annually deem these values as agreed to by consensus in the 2014 Workshops, then AIC is formally requesting in this submission that the measure values and NTG ratios used in the IPA program analyses, as represented in Appendix 7, are hereby deemed to determine the estimated savings achieved by the programs.”

- "AIC again formally requests approval for an indeterminate fluctuation in savings that may occur by program year end."

- "AIC once again seeks confirmation that AIC is permitted to recover costs that incidentally (3 -5%) exceed the estimated program costs as consistent with prior ICC [Illinois Commerce Commission] findings."

- "AIC is requesting the Commission pre-authorize a 20% budget shift across program years for the multi-year (PY8 and PY9) programs while remaining within the total approved multi-year program budget to allow for successful energy efficiency programs to continue operation in the early (or later) program years of the multi-year contract."

- "In the event the ICC does not approve the consensus item from the Staff Report regarding using savings estimates based on the current IL-TRM and NTG, AIC is formally requesting that these values be deemed for the implementation and evaluation for the determination of achieved savings on an annual basis."

- "AIC intends to continue to treat Section 8-103 and 16-111.5B evaluation budgets as merged and operated as a single budget; to the extent ICC [Illinois Commerce Commission] approval is necessary to continue this practice, AIC requests it."

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 approve the incremental energy efficiency programs proposed by Ameren.

ComEd’s assessment includes identification of ten energy efficiency programs for inclusion 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.

ComEd Energy Efficiency Offerings

Program	Net Savings (MWh)		Two Year Program Cost	TRC
	Program Year 1	Program Year 3		

LED[5] Streetlighting	6,077	12,156	$12,663,103	9.02
Residential Lighting(Moved from 8-103)	247,648	241,541	$77,270,755	16.56
Energy Stewards	944	944	$277,000	1.51
Door-to-Door Light Bulbs	1,255	1,255	$2,153,400	1.51
Middle School Take-home Kits	1,354	1,354	$1,304,316	1.25
Direct Install - Schools (Clear Result)	4,548	4,785	$2,148,292	1.06
Direct Install - Schools (Matrix)	6,156	6,156	$1,978,350	1.67
Demand Control Ventilation (Matrix)	6,125	6,125	$2,531,072	2.85
Demand Control Ventilation (Sodexo)	5,658	5,658	$1,713,040	6.11
New Construction	2,339	4,667	$1,749,776	1.25

The IPA indicates all of ComEd's programs are for two years. The net savings at the busbar are 282,104 MWh for the first program year, and 284,651 MWh in the second program year. These programs are forecasted to deliver 159 MW of reduction in peak procurement for the 2015-2016 program year. The savings attributable to eligible retail customers is 103,039 MWh in the first program year, and 104,652 MWh in the second program year. The IPA believes that ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs should be approved pursuant to Section 16-111.5B(a)(5).

According to the IPA, one of the proposed commercial programs, a commercial LED replacement program, was determined by ComEd in consultation with stakeholders to not conform with ComEd's issued RFP. The proposed approach contained unreasonable risks to consumers because the program could void warrantees and create electrical safety hazards. Upon a review of bid materials, the IPA agrees with this recommendation and does not recommend approval of this program in its Plan.

The IPA says ComEd, as well as stakeholders invited to review in the bid evaluation process, reached consensus that a K to 8 Public School Proposal, delivering energy assessments and turnkey installation of no cost, low cost, and capital measures in public schools, was "duplicative" of existing DCEO direct installation offerings to ComEd's public school customers. The IPA agrees with this determination. The IPA understands these to be similar offerings targeted to the same customer base, and does not believe that customer interests would be served by a separate delivery channel. The IPA therefore does not recommend approval of this program in its Plan.

[5] Light Emitting Diode is abbreviated as "LED" throughout this Order.

ComEd and reviewing stakeholders also reached consensus that a commercial behavior program proposal was "duplicative" of ComEd's existing behavioral offering. The proposed program features an "online portal providing customers with integrated billing, benchmark, weather, building, and savings data." The IPA believes ComEd's existing program and the proposed program appear to feature significant overlap in methodology and approach, although it is notable that the proposed program would serve a defined subset of those customers for whom the existing program is available. As such, the IPA says one could envision the proposed program having additive value as a more targeted product, achieving additional efficiencies. The IPA asserts that even so doing, it would still risk significantly eroding the savings potential of the existing program, factors which the IPA suggests may have informed ComEd and stakeholders in reaching consensus that this program is "duplicative."

The IPA agrees with this determination. However, as this proposal featured a TRC ratio of well less than 1.0, the IPA recommends it not be included first on that basis, with the consideration of this program as "duplicative" coming only should some change in estimated TRC make it relevant for inclusion.

In its submittal, the IPA says ComEd also identified 9 of its 11 programs as "competing" but not "duplicative," in other words, appropriate delivery conditions could be structured to ensure that consumers benefit from multiple delivery channels, and thus the presence of a similar program would not be grounds for exclusion. Upon review of these programs and application of the seven-factor inquiry, the IPA agrees with those determinations.

ComEd has requested that, "[t]o the extent that the IPA and the ICC [Illinois Commerce Commission] approve procurement of the programs ComEd requests that approval be for both years." The IPA agrees with this request. Besides this determination, the IPA requests that the Commission approve the incremental energy efficiency programs identified by ComEd.

3. Block Energy

The IPA recommends two slight refinements to the basic strategy from the 2014 Procurement Plan, based on comments received on the draft plan.

- The target volumes and timing of procurements for the upcoming delivery year will be as follows. Volume targets for the April 2015 procurement event will be 106% of the expected peak and 100% of the expected off-peak load for July and August (load and price during these months' peak periods typically experience high volatility; 100% for June (peak and off-peak), September and October (peak and off-peak); and 75% for November through May (peak and off-peak). The IPA recommends that the utilities update their load forecasts in March 2015, and that the recommendations be recomputed accordingly. A second procurement event will be held in September 2015 to bring the hedge levels to 100% for the period November 2015 – May 2016. The IPA says the effect of this refinement is that

the 106% hedge level will only apply to the July and August peak periods. For the next procurement pan, the IPA intends to take a closer look at this level of hedging and may recommend further adjustments.

- The volumes to be procured for 2016-2017 and 2017-2018 delivery years will be divided as equally as possible between the April 2015 and the September 2015 procurement events. In addition to providing additional cost averaging, the IPA says delaying the hedging of some of the open position will permit more time to obtain additional information about customer migration. Additionally, this refinement will help to divide the procurement costs more evenly. If the volume procured in April and September is about the same, the IPA says there will be less of a difference in unit procurement cost.

The following tables summarize the IPA's proposed hedging strategy.

Summary of Proposed Energy Hedging Strategy					
April 2015 Procurement			September 2015 Procurement		
June 2015-May 2016 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	November 2015-May 2016	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. and Oct. 100% peak and off peak Nov. - May 75% peak and off peak	25%	12.5%	100%	25%	12.5%

The IPA provides tables demonstrating the quantities of block energy to be purchased during the April 2015 procurement as well as the proposed supplemental procurement in September 2015 procurement. The IPA emphasizes that the tables reflect preliminary volumes, which will be adjusted using the March 2015 expected load forecasts and will also include newly approved energy efficiency programs. The tables below summarize the tables presented by the IPA.

April Procurement for Delivery Year 2015-2016

	Ameren Required Purchases (MW)		**ComEd Required Purchases (MW)**	
	Peak	**Off-Peak**	**Peak**	**Off-Peak**
June-15	750	475	1,475	1,200
July-15	875	625	1,950	1,425
Aug.-15	875	600	1,550	1,150
Sept.-15	600	450	1,150	925
Oct.-15	475	325	1,000	750
Nov.-15	325	250	650	550

Dec.-15	400	375	725	625
Jan.-16	450	350	725	650
Febr.-16	425	350	700	575
March-16	350	275	600	500
April-16	275	200	550	375
May-16	300	200	575	425

September Procurement for Delivery Year 2015-2016

	Ameren Required Sept. 2015 Purchases (MW)		ComEd Required Sept. 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Nov.-15	200	175	475	400
Dec.-15	250	225	550	475
Jan.-16	275	250	525	450
Febr.-16	250	225	500	425
March-16	225	175	450	375
April-16	175	150	400	325
May-16	175	175	425	325

April 2015 Procurement for Plan Year + 1

	Ameren Required April 2015 Purchases (MW)		ComEd Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-16	200	125	275	150
July-16	200	175	375	250
Aug.-16	200	150	350	200
Sept.-16	125	125	200	100
Oct.-16	125	100	125	25
Nov.-16	125	100	150	75
Dec.-16	150	150	250	150
Jan.-17	175	150	225	150
Febr.-17	175	150	200	125
March-17	150	125	150	50
April-17	125	100	100	25
May-17	125	100	100	50

September 2015 Procurement for Plan Year + 1

	Ameren Required April 2015 Purchases (MW)		ComEd Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-16	175	125	275	150
July-16	200	150	375	250
Aug.-16	200	150	350	200
Sept.-16	150	125	200	125
Oct.-16	100	75	125	25
Nov.-16	125	100	150	75
Dec.-16	175	125	225	175
Jan.-17	175	150	225	150
Febr.-17	175	125	200	125
March-17	150	125	125	75
April-17	100	100	75	0
May-17	100	100	75	25

April 2015 Procurement for Plan Year + 2

	Ameren Required April 2015 Purchases (MW)		ComEd Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-17	125	75	0	0
July-17	150	100	75	0
Aug.-17	150	100	50	0
Sept.-17	100	75	0	0
Oct.-17	50	25	0	0
Nov.-17	50	50	0	0
Dec.-17	75	75	0	0
Jan.-18	100	75	175	150
Febr.-18	100	75	175	125
March-18	75	50	150	100
April-18	50	25	100	75
May-18	75	50	100	100

September 2015 Procurement for Plan Year + 2

	Ameren Required April 2015 Purchases (MW)		ComEd Required April 2015 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
June-16	100	75	0	0
July-16	125	125	50	0
Aug.-16	125	75	50	0
Sept.-16	75	75	0	0
Oct.-16	50	50	0	0
Nov.-16	75	25	0	0
Dec.-16	100	75	0	0
Jan.-17	75	75	200	150
Febr.-17	100	75	175	150
March-17	75	50	125	75
April-17	50	50	125	75
May-17	50	25	125	100

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.

4. Capacity

The IPA recommends a slight change in strategy with respect to hedging capacity price risk for Ameren. As a matter of background, for Ameren, the 2013

Procurement Plan recommended no additional procurement of capacity because the majority of forecasted capacity requirements were procured in prior IPA procurements. The IPA also says it was uncertain if MISO would be granted FERC approval to move from a monthly capacity construct to a yearly construct (approval was later granted by FERC). The 2014 Procurement Plan likewise did not recommend procuring any capacity for Ameren. According to the IPA, this decision was driven by switching uncertainty and the fact that existing purchases from the 2012 Procurement Plan accounted for the majority of forecasted requirements.

Commencing with the 2015-2016 Delivery Year, the IPA indicates Ameren has no remaining IPA purchases of capacity. Ameren would therefore be expected to successfully purchase all of its capacity requirements via MISO's annual capacity auction and this would be the first year since the IPA was formed that Ameren has no forward hedging of capacity. While the IPA expects the upcoming MISO capacity auction will demonstrate sufficient liquidity to satisfy the requirements of Ameren, the timing of the auction could result in an event that abruptly increases rates for retail customers because, the MISO auction only clears two months prior.

The IPA believes that, for the 2016-2017 delivery year, it makes sense to hedge some portion of Ameren forward capacity requirements via bilateral contracts. This could protect against the potential for an event whereby Ameren customers are exposed to sudden and dramatic increases in capacity prices if all of the capacity were procured through the MISO auction at price to be known after the auction has cleared. The IPA says since the MISO capacity auction occurs less than two months before the start of the delivery year there is little opportunity for Ameren customers to anticipate the impact of a high capacity price.

In the IPA's view, it is likely that capacity suppliers will add price premiums to bilateral offers as a hedge against lost sales opportunities which could arise if the MISO auction yields prices higher than expected. The IPA also says it is unknown whether the bilateral capacity market provides sufficient liquidity to ensure competitive prices. While the downside potential of excessive price premiums is real, the IPA believes this risk should be managed by the use of confidential price benchmarks as recommended by the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and approved by the Commission. The IPA says any solicitation of bilateral capacity for Ameren that exceeds these price benchmarks could result in supplier offers being rejected by the Commission. The IPA indicates Ameren would then revert back to procuring capacity via the MISO auction.

Summary of Proposed Capacity Hedging Strategy			
	June 2015-May 2016 (Upcoming Delivery Year)	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
Ameren	100% MISO Auction*	50% RFP in Sep. 2015	25% RFP in Sep. 2015**
ComEd***	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

NOTES:
* MISO Auction is expected to clear in April 2015.
** Subject to the consensus among the IPA, Staff, and Procurement Monitor.
*** PJM RPM Base Residual Auctions for 2015-16, 2016-17 and 2017-18 have already cleared; although there may be incremental auctions for additional capacity needs they should have little impact on the PJM capacity prices for those years.

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2015 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.

For Ameren, the IPA says the results of the next MISO capacity auction will most likely be announced in April 2015, around the same time as the first procurement event recommended in this Plan. Given that timing, the IPA recommends that no capacity be procured for the 2015-2016 delivery year and Ameren have 100% of its 2015-2016 requirements satisfied via the 2015 MISO auction. Because it is not known whether the MISO capacity auction will be before or after the IPA April procurement event, and because a price spike in the MISO auction could roil the bilateral capacity market for some time thereafter, the IPA recommends a capacity hedge procurement for Ameren be held simultaneously with the September 2015 procurement event proposed in this Plan. The IPA recommends that the capacity procurement target be 50% of the 2016-2017 capacity obligation for Ameren as estimated based on the expected load forecast submitted by Ameren in July 2015.

At this time, the IPA is not recommending a capacity procurement for the 2017-2018 period or beyond but recognizes that unexpected capacity retirements, or significant exports of capacity from MISO into PJM, could adversely impact the capacity market in MISO. Therefore, the IPA requests that the Commission pre-approve the procurement of 25% of the 2017-2018 capacity obligation for Ameren, simultaneously with the September 2015 procurement event, subject to consensus among the IPA, Staff and the Procurement Monitor. The IPA intends to continue monitoring the capacity market in MISO and may propose additional adjustments to the capacity hedging strategy for Ameren in future procurement plans.

5. Ancillary Services and Transmission Service

The IPA indicates both Ameren and ComEd purchase their ancillary services and transmission services from their respective RTOs, MISO and PJM. The utilities also manage 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. Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures.

The IPA reports that ComEd provided information regarding its existing demand response programs for 2014 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 72,700 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 1,200 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 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 48 MW of capacity from the program into the PJM capacity auction for the 2017 Planning Year.

The IPA says Ameren has recently completed a Voltage Optimization Pilot Program, offers real-time pricing options, and had its peak time rebate program provisionally approved by the Commission this January in Docket No. 13-0105.

The IPA does not propose any additional demand response programs for the 2015-2016 delivery year. The IPA states that Peak Time Rebate (or Savings) programs create value through reduction in capacity charges and 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. The IPA maintains that recent court rulings regarding demand response may necessitate additional consideration of demand response in future procurement plans.

7. Clean Coal

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025. As a part of the goal, the Plan must also include electricity generated from clean coal facilities. While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act, the IPA says Section 1-75(d) describes two special cases: the "initial clean coal facility" and "electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities ("retrofit clean coal facility"). Currently, the IPA is unaware of any facility meeting the definition of an "initial clean coal facility" that has announced plans to begin operations within the next five years.

In Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal resource starting in the 2017 delivery year. The IPA notes a recent Illinois Appellate Court ruling on the appeal of the Commission's Final Order in Docket No. 12-0544 may provide additional certainty for the project's development. On July 22, 2014, the appellate court upheld the Commission's decision to require ComEd and Ameren to recover FutureGen sourcing agreement costs through a competitively-neutral retail distribution charge applicable to all utility distribution customers (including ARES customers).

The IPA is not aware of any additional change in status of the project that would hinder FutureGen's ability to deliver clean coal electricity as anticipated. Also, the IPA is not aware of any additional retrofitted clean coal facilities seeking inclusion in the Procurement Plan.

The IPA reports it has been approached by a team representing Sargas, Inc. ("Sargas"), a US subsidiary of Sargas AS, a Norwegian technology company. Sargas is seeking to develop a coal-fired power plant in Mattoon designed to burn Illinois coal with 90% post-combustion carbon capture, with captured carbon then used for local enhanced oil recovery. The IPA says the project would be a single module, 80 MW facility seeking to begin construction as early as 2016 and begin operation as early as 2019.

According to the IPA, the regulatory treatment afforded proposed clean coal projects varies significantly by project type. The IPA Act contains provisions specific to an "initial clean coal facility," "retrofitted coal-fired power plants," a "clean coal SNG [substitute natural gas] facility," and a distinct "clean coal SNG brownfield facility." Based on conversations with the Sargas team and the project description provided by Sargas in its comments on the IPA's draft plan, the IPA understands that the proposed Sargas project, a high-pressure combustion facility located on a greenfield site, would not fit into any of the above categories. Instead, the project would constitute a "clean coal facility" as that term is used in the Section 1-10 of the IPA Act.

The IPA says it does not have a mechanism for considering sourcing agreements from a standard, non-delineated "clean coal facility" for inclusion in its Plan, and Sargas has not submitted sourcing agreements to the IPA for consideration. Instead, Sargas has requested that the IPA include a competitive clean coal procurement in its 2015 Procurement Plan. In Sargas's view, again as the IPA understands it, the IPA's authority to conduct a competitive clean coal procurement for projects such as Sargas stems from the broad language of the clean coal portfolio standard as manifest in Section 1-75(d)(1) of the IPA Act.

The IPA has concerns with this proposal. The IPA notes the clean coal portfolio standard contains a rate impact cap, limiting the average net increase to ratepayers to a maximum 2.015% for sourcing agreements with clean coal facilities executed pursuant to the IPA's Plan. Based on representations made by FutureGen in February 2013, FutureGen 2.0's expected rate impact would be 1.32%, or approximately 65% of the statutory limit. The IPA says Sargas has represented having a cost structure lower than FutureGen with output of roughly half that of FutureGen's; assuming sourcing agreements similar to FutureGen's, and assuming the accuracy of FutureGen's rate impact representations, it is possible that both projects could fit under this threshold.

The IPA states that Section 1-75(d)(5) of the IPA Act provides an express mechanism for the IPA's consideration of sourcing agreements between alternative retail electric suppliers and owners of retrofitted clean coal facilities. But, for a non-retrofitted greenfield "clean coal facility," such as Sargas, the IPA says the IPA Act contains no such mechanism for considering sourcing agreements involving ARES.

As the IPA conducts procurement events only on behalf of utilities' eligible retail customers absent express authority to the contrary, the IPA believes that any "clean coal facility" sourcing agreements considered under the general provisions of Section 1-75(d)(1) would run only between the facility owner and the utilities to supply eligible retail customers. With a significantly smaller and migrant customer base responsible for covering sourcing agreement costs, the IPA suggests any sourcing agreement produced through a competitive "clean coal facility" procurement would either violate the statutory rate cap or cover only a small portion of the project's output. As a result, the IPA believes it would not be possible or wise to conduct a competitive procurement to solicit sourcing agreements for a "clean coal facility."

Based on this review, the IPA believes that Sargas's best path to a sourcing agreement covering the full output of its proposed clean coal facility would be through express statutory authority developed by the Illinois General Assembly. Nonetheless, the IPA invited Sargas, Inc. and its team to participate in the resulting plan approval process before the Commission, where Sargas may offer an alternative interpretation of judicial precedent and governing law for the Commission's consideration.

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 and 2014, 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: 75% wind, 6% (by June 1, 2015) photovoltaics ("PV") and 1% (by June 1, 2015) distributed generation which can be included within the PV requirements.

As the target total renewables and wind requirements are forecasted to be met in the 2015-2016 delivery year, the IPA does not recommend procuring any additional wind or generic renewable resources on behalf of Ameren or ComEd during the upcoming year. However, the IPA indicates the photovoltaic and distributed generation requirements for both utilities are not forecasted to be met. To achieve statutory compliance, the IPA recommends a Spring 2015 procurement of Solar Renewable Energy Credits procurement to meet each utility's PV requirements for the 2015-2016 delivery year. The IPA indicates quantities to be procured will be based upon the "Remaining Targets" as calculated from the updated March 2015 load forecasts and will be limited to the funds available in the Renewable Resources Budget as reported at that time. The IPA maintains that should consensus on the March 2015 load forecasts not be reached, the quantities of SRECs to be procured for the 2015-2016 delivery year will be based upon the "Remaining Target" rows of Table 8-1 and Table 8-2 of the Plan for that delivery year. To the extent practicable, the IPA suggests the structure, process and contracts for the procurement will be based upon those used for the last REC procurement conducted by the IPA in 2012.

The IPA says the procurement of DG resources to meet those requirements would require contracts of at least 5 years. Because future load forecasts could change and result in a curtailment of the existing LTPPAs from 2010, the IPA claims there could be risks of conflicting curtailment requirements if new multi-year contracts were entered into using funds collected from eligible retail customers. Therefore the IPA does not recommend any use of the Renewable Resources Budget for making new commitments beyond the prompt delivery year. The IPA suggest this may constrain the use of those funds to meeting the utilities' RPS mandates rather than any broader policy goals such as fostering the development of new renewable resources in Illinois. Absent legislative changes to the IPA Act and the PUA, the IPA says this is the limit to what the IPA can propose for use of the Renewable Resources Budget.

The IPA proposes using funds collected and available (as of the March 2015 load forecast) from hourly customers to conduct a procurement from existing DG resources to allow the utilities to meet their DG requirements and updated per the March 2015 load forecast. The IPA notes that the recently enacted new Section 1-56(i) of the IPA Act requires the development of a supplemental PV procurement plan that will include photovoltaic DG resources. To the extent practicable, and accounting for choices yet to be made on procurement structure and design, the IPA suggests any procurement of DG resources for the utilities should be considered in a manner that could be synchronized with the Section 1-56(i) procurement process.

The IPA recommends that the Commission require the utilities to produce updated load forecasts on March 13, 2015 and to curtail the Long-Term Power Purchase Agreements if the updated forecast indicates the renewable budget will be exceeded. The IPA says that forecast would also be used for determining the available budget and targets for any PV procurements. Under the IPA's proposal, these forecasts will also be used to plan the April 2014 forward hedge procurement event.

The table below shows that Ameren's current renewable resource contracts will cover its total renewables RPS targets for the next two delivery years. Assuming that no additional purchases of renewable energy resources are made, the IPA indicates Ameren will fall short of meeting its RPS requirements in the 2017-2018 delivery year by 9%. In the 2018-2019 and 2019-2020 delivery years, the shortfall for total renewables will reach 43% and 48%, respectively.

The IPA Act also sets separate goals for wind, photovoltaic, and distributed renewable generation as fractions of the total renewables requirement. The table shows that Ameren is projected to meet its wind generation goals for the next three delivery years. Assuming that no additional purchases are made, the IPA indicates Ameren will fall short of the wind goal by 25% and 31% in the 2018-2019 and 2019-2020 delivery years, respectively. Assuming that no additional purchases of PV and DG are made, Ameren will fall short of the photovoltaic and distributed generation goals in each delivery year. Unlike the projection in last year's Procurement Plan, the IPA says Ameren is projected to have surplus RPS funds with which to purchase renewables.

The IPA recommends a one-year SRECs procurement to meet Ameren's PV requirement for the 2015-16 delivery year.

Ameren's Existing RPS Contracts and RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2015-2016	Target (MWh)	651,767	488,825	39,106	6,518
	Purchased (MWh)	1,008,810	979,916	8,894	0
	Remaining Target (MWh)	-357,043	-491,091	30,212	6,518
2016-2017	Target (MWh)	707,299	530,474	42,438	7,073
	Purchased (MWh)	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	-321,946	-446,377	30,044	7,073
2017-2018	Target (MWh)	948,538	711,403	56,912	9,485
	Purchased (MWh)	854,396	848,338	6,058	0
	Remaining Target (MWh)	94,142	136,935	50,854	9,485
2018-2019	Target (MWh)	1,057,316	792,987	63,439	10,573
	Purchased (MWh)	600,000	596,571	3,429	0
	Remaining Target (MWh)	457,316	196,416	60,010	10,573
2019-2020	Target (MWh)	1,164,230	873,172	69,854	11,642
	Purchased (MWh)	600,000	596,571	3,429	0
	Remaining Target (MWh)	564,230	276,601	66,425	11,642

The table below shows ComEd's current RPS contracts relative to its renewables requirements. ComEd's forecast indicates that enough renewables have been procured to meet its total renewables and wind targets for the 2015-2016 delivery year. In subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 7% in 2016-2017, 22% in 2017-2018, 41% in 2018-2019, and 47% in 2019-2020. ComEd is also forecasted to fall short of the photovoltaic and distributed generation targets in each of the five delivery years considered in the Plan and to fall short of the wind target in the 2017-2018 delivery year and beyond. Unlike the projection in last year's Procurement Plan, ComEd is projected to have surplus RPS funds with which to purchase renewables.

The IPA recommends a one-year SRECs procurement to meet ComEd's PV requirement for the 2015-16 delivery year.

ComEd's Existing RPS Contracts and RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2015-2016	Target (MWh)	1,319,414	989,561	79,165	13,194
	Purchased (MWh)	1,464,204	1,433,838	29,395	0
	Remaining Target (MWh)	-144,790	-444,277	49,770	13,194

2016-2017	Target (MWh)	1,681,101	1,260,826	100,866	16,811
	Purchased (MWh)	1,561,397	1,340,016	27,895	0
	Remaining Target (MWh)	119,704	-79,190	72,971	16,811
2017-2018	Target (MWh)	1,961,224	1,470,918	117,673	19,612
	Purchased (MWh)	1,533,198	1,233,838	27,887	0
	Remaining Target (MWh)	428,026	237,080	89,786	19,612
2018-2019	Target (MWh)	2,150,200	1,612,650	129,012	21,502
	Purchased (MWh)	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	888,475	378,812	101,125	21,502
2019-2020	Target (MWh)	2,385,685	1,789,264	143,141	23,857
	Purchased (MWh)	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	1,123,960	555,426	115,254	23,857

The table above includes ComEd's statutory targets for wind, photovoltaic and distributed renewable procurement over the five-year projection horizon.

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.

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. For the 2013-2014 and 2014-15 delivery years, the IPA notes the Commission approved the curtailment based on March updated load forecasts of long-term renewables contracts to keep the cost of renewable energy resources below the statutory cap. Curtailment has been required of ComEd's contracts but not Ameren's. According to the IPA, Ameren's and ComEd's load forecasts have now significantly increased based on the recent observation of a significant number of municipalities suspending their municipal aggregation programs and returning to utility supplied service. Because the delivery year RPS budget is a function of the amount of eligible utility load, which has increased relative to last year's load forecasts, the IPA says it is forecasted that the delivery year RPS Budgets exceed the Contractual Cost for RECs already procured in each delivery year. Therefore, both Ameren and ComEd are forecasted to have RPS funds available in each of the five delivery years covered by this Plan.

Ameren LTPPA Curtailments Required to Meet Spending Cap

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction
2015-2016	9,183,529	13,042,188	$3,858,659	7,826,000	0.0%
2016-2017	10,403,861	13,032,625	$2,628,764	7,796,000	0.0%
2017-2018	9,412,155	13,004,827	$3,592,673	7,957,000	0.0%
2018-2019	8,000,000	12,974,820	$4,974,820	8,000,000	0.0%
2019-2020	7,999,000	12,966,712	$4,967,712	7,999,000	0.0%

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
2015-2016	23,177,988	28,538,822	5,360,834	22,613,000	0.0%
2016-2017	23,498,871	28,051,960	4,553,089	22,674,000	0.0%
2017-2018	23,792,264	28,206,252	4,413,988	23,137,000	0.0%
2018-2019	23,431,544	28,281,063	4,849,519	23,357,000	0.0%
2019-2020	23,558,293	28,327,164	4,768,871	23,484,000	0.0%

The IPA says the contracted REC costs for 2015-16 for Ameren and ComEd are respectively 70% and 81% of the current estimates of their respective 2015-16 RPS budget caps. Those budgets depend directly on eligible retail load, so it appears to the IPA that as long as ComEd's March 2015 forecast for 2015-16 load is at least 81% of its July 2014 forecast value, and as long as Ameren's is March 2015 forecast for 2015-16 load is in turn at least 70% of its July 2014 forecast value, neither utility will have to curtail its renewable LTPPAs.

The IPA states that while it appears unlikely that curtailment of the LTPPAs would be required in the 2015-2016 delivery year, the IPA recommends that a final determination be based upon the March 2015 load forecasts. In the event that curtailments are required, the IPA recommends that the methodology adopted in the Commission's Order on Rehearing of the 2014 Procurement Plan be employed for the calculation of REC prices for curtailed RECs including the use of Annual Contract Values. The IPA believes it is highly unlikely that curtailments will be required, and as hourly ACP funds are proposed for a procurement of RECs distributed generation systems, therefore, the IPA proposes to address a potential curtailment through continuing its prior offer to purchase curtailed RECs at the imputed REC prices from the 2010 contracts using the Renewable Energy Resources Fund.

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 Renewable Energy Resources Fund ("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; as of May 31, 2014; for Ameren, the value is $5,556,580; for ComEd, the value is $7,842,658.

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. For the 2013-2014 and the 2014-2015 delivery years, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs, and the IPA recommends a continuation of that policy.

The IPA notes that based on load forecasts, the curtailment of the LTPPAs appears unlikely in 2015-2016. The IPA says the utilities have a concurrent shortfall in meeting their statutory DG targets. It therefore appears to the IPA that utilizing the already collected, and otherwise unspent, hourly ACP funds to allow the utilities to meet their DG targets would be appropriate to further an aspect of the utilities' RPS obligations. Additionally, as contracts for DG resources must be "no less than 5 years" in length, the IPA says entering into 5 year contracts using existing ACP funds already collected from hourly customers eliminates the load migration risk present with the renewable resources budget (from which long-term contracts have already been subject to curtailments) while ensuring that there are no impacts on customer rates.

The IPA states that although distributed generation systems from qualifying facilities were eligible to participate in the IPA's prior renewable energy resource procurements, this proposal marks the first time the IPA has sought to conduct a procurement event specifically targeting DG resources. As certain statutory language applies only to procurement from distributed generation, the IPA says this left the IPA with a number of open questions and scant precedent.

In developing a DG procurement using Hourly ACP funds, the IPA is guided by the following principles:

The IPA's DG procurement should endeavor to bring the utilities into compliance with statutory requirements for RECs from distributed generation systems, to the extent possible given the balance of existing hourly ACP funds. The sooner a successful, competitive DG procurement event is conducted, the sooner the IPA will have made progress in fulfilling its duty under the law of procuring renewable resources for the utilities.

The procurement must be structured so as to ensure the procurement proceeds in a manner consistent with the governing law. With respect to a DG procurement, the IPA says this includes the obligation that "to the extent available," half of the DG RECs procured originate from "devices of less than 25 kilowatts in nameplate capacity."

Any DG procurement must be structured mindful of the IPA's obligation to produce procurement plans aimed at ensuring "adequate, reliable, affordable, efficient,

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

Lastly, the IPA should proceed with awareness of its concurrent supplemental procurement planning process under Section 1-56(i) of the IPA Act, noting both opportunities for synergies between the two procurements and market confusion challenges that could result from two separate-but-similar procurement processes conducted by the same Agency with distinct counterparties governed by distinct sections of the IPA Act.

Section 1-75(c)(1) of the IPA Act also contains specific provisions on the use of third-party aggregators as counterparties:

> In order to minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity. These third-party organizations shall administer contracts with individual distributed renewable energy generation device owners.

The IPA is concerned that this requirement may constitute a meaningful limitation on participation, especially from smaller (and primarily residential) distributed photovoltaic systems. The IPA says the average size of a residential photovoltaic system is 5 kW, meaning that 200 such systems would need to be aggregated for participation in a DG procurement event. The IPA believes that the development and organization of the Illinois distributed generation market required to produce sufficiently sized bids is indeed possible—but it may require time and flexibility, and the IPA has developed its proposed procurement approach accordingly.

After analysis and review of comments from stakeholders and further internal consideration (including coordination, where possible, with the proposed supplemental PV procurement plan being developed pursuant to Section 1-56(i) of the IPA Act), the IPA has settled on a model similar to Option #1 identified in the draft plan. The IPA is confident in its ability to effectively execute its traditional procurement process involving the block procurement of renewable energy credits with competitive bids selected on the basis of price. As the IPA is proposing a distributed generation procurement to meet statutory DG targets, and not simply a solar photovoltaic REC procurement, the IPA also believes that this model leaves it best able to accommodate RECs from generating technologies beyond solar photovoltaics.

The IPA recognizes that given the limited amount of distributed generation currently in Illinois, this approach's success hinges on the ability of the Illinois DG market to both self-organize and grow. To accommodate those needs, the IPA is proposing to conduct its DG REC procurement later in 2015 (September), and to allow participation from DG systems not yet constructed but capable of delivering RECs by the conclusion of the 2015-2016 delivery year. Additionally, the IPA proposes to allow

bids to contain DG systems of all qualifying sizes and resource types, and will evaluate systems within bids on the basis of price and system size.

The IPA is proposing a DG renewable resource procurement using hourly ACP funds. The products sought to be procured are RECs from DG systems that are interconnected with Ameren, ComEd, a municipal utility in Illinois, or a rural electric cooperative in Illinois.

The IPA states that unlike with its supplemental PV procurement under Section 1-56(i) of the IPA Act, nothing in the law governing this DG procurement distinguishes between "new" or "existing" systems. As a result, the IPA's sole requirement about system build date is that all participating DG systems must begin delivery of RECs sometime during the 2015-2016 delivery year. The IPA proposes for contracts to be for the five delivery years starting with 2015-2016 delivery year.

The IPA says all technology types of DG as defined by the IPA Act are eligible to participate; this includes DG "powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams."

The IPA seeks to commit only those hourly ACP funds that have been collected (and, for those funds held by ComEd, not allocated to the purchase of curtailed RECs from the 2014-2015 delivery year), and will procure DG RECs until those funds are fully spent or the utilities' 2015-2016 DG goals are met.

The IPA's proposes approach is to procure DG through a single procurement event in a competitive bid process in September 2015 with two categories of systems eligible to participate. The first category is for systems under 25 kW, the second for systems between 25 kW and 2 MW.

The IPA states that as required by law, it must endeavor to ensure that, to the extent available, half of the total RECs procured by the IPA are from systems under 25 kW in size. Section 16-111.5(e) of the PUA requires that the IPA's procurement process be conducted through selecting competing bids "solely on the basis of price." The IPA believes these requirements can be properly balanced by procuring on the basis of price within each individual market segment (<25kW, and 25kW to 2 MW), selecting the next most competitive bid within a market segment when that segment represents below half of the expected DG RECs to be delivered (to the extent such a bid is available). This means that a sub-25kW system can be selected ahead of an above-25kW system with a lower price, but only if that selection is required to reach the target 50% of DG RECs from sub-25kW systems. The IPA says that as in other procurements conducted by the IPA, all winning bids must also be below "benchmarks" developed "for each product procured."

Under the IPA's proposal, a bid will specify an annual REC volume to be delivered, and a five-year total. For the 2015-2016 delivery year, RECs from any month in the delivery year will be eligible. The IPA says the bidder must identify the specific system(s) that will provide the RECs; "speculative bidding" of RECs from systems not specifically identified will not be permitted. Evidence regarding the systems may include, but is not limited to, letters of intent, signed contracts, interconnection or net metering applications, local permits, etc.

The IPA says bids must be at least one megawatt in size, but may feature a number of DG systems of all qualifying sizes and resource types. The bidder will designate REC prices specific to the individual systems comprising the bid; this may be a single, uniform price across all systems, or system-specific prices. Just as not all offered blocks of energy from a single bidder may win in the IPA energy procurement process, the IPA says not all offered systems may necessarily win in the IPA's DG procurement process. Bidders may not designate different REC prices for the RECs generated from a single distributed generation system, and in order to meet the procurement targets and budget, the marginal bidder in the evaluation of bids could receive a contract for a portion of RECs from a single system and will have the option of whether or not to accept that award.

Within 2 days after a procurement event featuring "sealed, binding commitment bidding" with bids selected "on the basis of price," the IPA states reports on the procurement event are submitted by the procurement administrator and the Commission's procurement monitor to the Commission for review. These reports contain bidding results and a recommendation for the rejection or acceptance of bids. The IPA says Commission issues a decision on whether to accept or reject the procurement results within 2 days after receiving the reports.

Within 3 days after the Commission's decision, "the Agency shall enter into binding contractual arrangements with the winning suppliers using the standard form contracts." To the extent not addressed elsewhere in this Plan, the payment and delivery schedules under those contracts will be contemplated in the litigation of this Plan and developed during the contract form development process after the Plan's approval.

Because Ameren and ComEd have separate compliance targets and budgets, winning bids will be assigned to the utilities based on the utilities' pro rata share of the total RECs procured in each category. The IPA will strive to develop a standard contract for both Ameren and ComEd, but should a standard contract not be developed a bidder will have to agree to sign the contract with the utility to which their RECs are assigned.

Each system covered by a contract awarded in this procurement must begin accumulating metered deliveries of renewable energy prior to the end of the 2015-2016 delivery year (May 31, 2016). Should a system not be completed in the required

timeframe, the bidder's contract volume will be reduced accordingly by the amount allocated to that system or the contract will be cancelled.

Contracts under this proposed procurement are between winning bidders and either Ameren or ComEd; the IPA is not a contract party as it will be for the DG procurement in the supplemental PV plan. The IPA says further details regarding the contracts will be developed by Procurement Administrator in consultation with the IPA, the Commission, utility, and other interested parties and subject to Commission oversight, after the Procurement Plan is approved by the Commission.

The IPA states that contracts will provide payment for RECs for a five year period starting at the time of the system's energizing date (defined as the first meter read registered in the applicable tracking system). Utility contracts will not feature payments prior to REC delivery, such as pre-payment at the execution of a contract or when a system becomes energized.

The IPA says it is required to recover the cost of conducting this procurement through bidder fees and to develop "standard credit terms and instruments." For this procurement, the IPA's proposals are as follows:

- All bidders will pay a $500 non-refundable bid participation fee. This fee is non-refundable and will be assessed evenly across all bidders.

- The credit requirement for participating in this procurement will be that a bidder will also provide a refundable deposit of $10/REC as part of the bidder registration process. Bidders who do not win will have their deposits refunded. For a bidder who only is successful for a portion of their bids, the refund will be prorated based upon their winning bids.

- Winning bidders will be assessed a Supplier Fee which reflects the balance of the cost of conducting the procurement less the total of the bid participation fees. An estimated Supplier Fee per REC will be announced prior to the opening of bidder registration, and the final Supplier Fee per REC will be announced after bidder registration is completed but prior to the bid due date. If the Supplier Fee is greater than the deposit, then winning bidders will have seven days after the approval of the procurement results by the Commission to pay the balance due to the IPA. If the Supplier Fee is less than the deposit, then the difference will be held by the IPA and refunded to the bidder upon notice by the utility that the project has begun delivery of RECs.

- Any system that is not successfully developed will forfeit its deposit for those RECs.

- The utility's counterparty under the contract will either be the owner of the system or an intermediary that will contract with the owner of the system.

> In either case, the party named during the procurement process will be the party that signs the contract. The contract may be transferred or assigned with consent from the IPA and utility. Such consent will be automatic if the ownership of the system changes, if the assignment is to an affiliate of the counterparty, or is for financing purposes. The counterparty will be required to effect such assignment or transfer in the event of bankruptcy or dissolution.

The IPA says that unlike with its proposed supplemental PV procurement plan being developed pursuant to Section 1-56(i) of the IPA Act, which does not define aggregator size, Section 1-75(c)(1) requires that aggregators "aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." As allowing bids below one megawatt in size could create significantly more contract counterparties, thus creating the "administrative burdens" that this provision was intended to ameliorate, the IPA understands that the law's one megawatt size threshold applies to all bids received (whether from a third party or a system owner).

The IPA proposes to allow for "self-aggregation" from system owners, so long as those bids are at least one megawatt. The bidder will serve as the counterparty with the utility in contracts for the delivery of RECs; in the case of non-system owners (third-party aggregators), the bidder must have ownership over the RECs or the contractual right to legally transfer or assign RECs to the utility. Bid size must be "at least one megawatt in installed capacity," but, bidders may not win for the full portion of their bids.

Given the number of systems required to constitute a full megawatt, the IPA suggests meeting a one megawatt threshold may be challenging for aggregators organizing bids built off of smaller systems. The IPA says it may be also especially challenging given the relatively small universe of existing DG systems in Illinois. Any participating system would both need to 1) have RECs available for procurement (i.e., not already under contract) and be willing to transfer available RECs;224 and 2) have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event.

Based on these factors, the IPA believes it is unlikely that a sufficient number of bidders would be prepared to deliver one megawatt blocks to a Spring 2015 DG procurement. Thus, to allow the market sufficient time to organize, the IPA seeks a September 2015 DG procurement. While a later procurement date may risk more time spent out of compliance with statutory DG procurement goals, the IPA will allow for the contact delivery of all RECs generated during the 2015-16 delivery year from winning bidders (and not only those RECs generated after the execution of contracts).

The IPA states that the RERF balance equals $128,358,022.71, the total amount received in the IPA's RERF attributable to ARES ACP payments less the cost of RECs purchased per the IPA's offer to use RERF funds to purchase curtailed RECs from the 2010 LTPPAs that were not purchased by ComEd using hourly ACP funds. The table

below shows the current IPA RERF balance sheet. The IPA states that in September 2014, the IPA expects to receive an estimated $77 million in ACPs for the June 2013 – May 2014 planning year. The IPA says these expected payments, in the aggregate, are significantly higher than prior year payments. The IPA claims the higher amount is a direct result of significant load switching from utility supply to Retail Electric Supplier ("RES") supply in recent months, primarily driven by municipal aggregation activities.

RERF Balance

Planning Year	Funds Received/Disbursed	Total ACPs
2009-10	2010 - Quarters 3 and 4	$7,148,261.61
2010-11	2011 - Quarters 3 and 4	$5,606,245.18
2011-12	2012 - Quarters 3 and 4	$2,156,777.61
2012-13	2013 – Quarters 3 and 4	$38,382,345.57
2012-13	2014 – Quarters 1 and 2 RECs Purchased	$(1,719,141.52)
2013-14	2014 – Quarter 3	$76,783,534.26
Aggregate Total		**$128,358,022.71**

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 in this Plan. The IPA states that newly enacted Section 1-56(i) of the IPA Act will require the IPA to develop a supplemental PV procurement plan to spend up to $30 million on RECs from photovoltaic resources from the RERF. That supplemental PV procurement plan will require review and approval by the Commission, and the results of procurements stemming from that supplemental PV procurement will also require Commission approval. While the supplemental PV procurement plan does not direct the IPA to fully utilize the full RERF balance, the IPA believes it is an important first step forward in allowing those funds to be used for their intended purpose. The IPA hopes that future legislative changes will add to the ease through which the IPA can use the remaining fund balance to further the RERF's purposes.

F. Process Design

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 have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the 2014 procurement events, the IPA says the process to receive comments from potential bidders can be restricted to changes to the forms, thus reducing Procurement Administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. The IPA claims this is because, prior to the 2014 procurement events, the forms, terms and instruments had become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. The IPA notes any procurement event to be conducted under the auspices of the 2015 Procurement Plan would be the ninth iteration of IPA-run procurement events, when including the April 2014 procurement event and planned September 2014 procurement event. In each iteration prior to 2014, the IPA says potential bidders 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 2014 procurement events, the IPA indicates potential bidders submitted only sparse comments on the proposed changes to the forms.

According to the IPA, the recommended improvements in regards to the forms apply to both the energy procurement and RPS procurement. The IPA says in the procurement events conducted for energy blocks and RECs in 2012 (the Rate Stability Procurement and the standard Spring Procurement including the RPS 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 procurement events). The documents used for the 2012 IPA-run procurement events 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 therefore recommends that the last used forms, namely the energy contracts used in the 2014 procurement events and RPS contracts used in the Spring 2012 RPS Procurements be

the starting point for the contracts used in the energy and SREC procurements associated with this Plan and the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified. The IPA believes for the DG procurement using hourly ACP funds new contracts will likely be needed and the development of those contracts should be coordinated, to the extent possible, with the contracts developed as part of the Section 1-56(i) supplemental PV procurement plan. Once consensus is reached among these parties, the IPA suggests the supplier comment process would be limited to discussion on proposed changes that have been made relative to the previously used contracts or to changes that suppliers believe are necessary because of changes to laws or regulations that directly affect the supplier or the terms of the contract. If based upon supplier comments, consensus to a change cannot be reached among these reviewing parties, then the IPA says the provisions in the prior contract (the 2014 energy contract or the Spring 2012 RPS contract) would be used.

The IPA indicates Section 1-75(h) of the IPA Act states that, “[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process.” The IPA says that in April, 2014 it adopted new administrative rules related to fee assessments that codify past practices including defining “bidders” and “suppliers” in procurement events as well as the process for determining those fees.

The IPA has historically recovered the cost of procurement events through two types of fees:

- A "Bid Participation Fee", which is a flat fee paid by all bidders as a condition of qualification; and
- "Supplier Fees", which are paid only by the winning bidders as a fee per block won at the conclusion of the procurement event.

The IPA states that for the last several procurements, the Bid Participation Fee has been nominal ($500), which means that the bulk of the costs of the procurement event (which are typically several hundred thousand dollars) are recovered from winning bidders through Supplier Fees. The IPA claims there are two risks for it from recovering costs in this manner:

1. If not all the blocks are procured (but no additional procurement event is held), the IPA will not recover the full cost of the procurement through the combination of the Bid Participation Fees and the Supplier Fees. The Supplier Fees associated with the blocks that are not procured will not be collected.

2. Suppliers may not necessarily pay the Supplier Fees on time (or pay them at all). Suppliers that have bids that are approved by the Commission proceed to the contract execution process with the utility and will get paid under that contract whether or not they have paid the Supplier Fees. When the structure of fees was

first introduced, non-payment of the Supplier Fees was an event of default under the contract with the utility. Suppliers had a very strong incentive to pay the Supplier Fees as failure to do so meant that they would not be able to get the compensated under the contract from winning the bid. As procurement events came to be IPA-run, this structure was abandoned as the responsibility for assessing fees to bidders is the IPA's and not the utility's. The incentives for suppliers to pay the Supplier Fees were reduced as a result.

In improving the procurement process design an objective of the IPA is to provide a structure by which the IPA is protected from non-payment of the Supplier Fees and potentially a structure that could adapt to the number of blocks actually procured.

The IPA claims there are two broad categories of solutions:

1. Maintain the current fee structure and use the pre-bid letter of credit provided by bidders as bid assurance collateral to ensure compliance with the payment obligation of the Supplier Fees.

2. Change the current fee structure to have the cost of the procurement largely paid upfront and bar suppliers that fail to pay all fees due from participation in IPA-run events for a period of time.

With the exception of the 2014 procurement events, the IPA says the pre-bid letter of credit has been strictly a credit instrument held for the benefit of the utility and its customers. The IPA states that the utility may draw upon the pre-bid letter of credit if the supplier fails to complete the contract execution process. At that point, the IPA says the utility has filed its rates based on the winning bids but would have to buy replacement supply, for which it can use funds under the pre-bid letter of credit to mitigate any impact of the default on rates.

Based on the comments on the draft procurement plan and upon further reflection, the IPA recommends that the approach used in the 2014 procurement events be implemented to support the procurement events recommended in the Plan this year. The IPA recommends maintaining the condition in the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain. Likewise, as used in the 2014 procurement events, the IPA says having an agreement between the IPA and the utility on how funds would flow back to the IPA for payment of the Supplier Fees.

The IPA recommends that two procurement events be held for purchase of energy blocks under the 2015 Procurement Plan. According to the IPA, all of the components of the procurement process would be conducted for the first of these two procurement events to be held in 2015. For the second procurement event for energy blocks under the Procurement Plan, the IPA proposes that certain activities would not occur as the second procurement event could rely on the documents or processes established for the first procurement event, as follows:

- The procurement administrator will rely on the contract and credit forms established in the first procurement event and suppliers would not comment anew on these documents;

- The procurement administrator will rely on the RFP design and benchmark methodology established in the first procurement event; and

- Suppliers that participate in the first procurement event will have access to an abbreviated qualification and registration process if they also participate in the second procurement event.

The IPA recommends holding one SREC procurement to be conducted in approximately April 2015, and does not anticipate a second SREC procurement event under the 2015 Procurement Plan. The IPA recommends the DG procurement be scheduled for September 2015.

Section 16-111.5(o) of the PUA states:

> On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.

According to the IPA, this year, Staff led an informal hearing for the purpose of receiving comments on the April 2014 procurement process. The IPA says comments were received only from Boston Pacific (the Commission's Procurement Monitor) and RESA. The IPA indicates RESA's comments focused only on full requirements procurement as did much of Boston Pacific's. The IPA says it took those comments into account for its consideration of full requirements. Boston Pacific's comments also related to observations on the winter 2014 price spikes and impact on procurement events in other states and thoughts on the timing of the bid day.

The IPA states that regarding bid day timing Boston Pacific had three recommendations. First, to allow time after the Spring procurement to allow for a contingency procurement event if needed; second, to avoid scheduling the bid day to conflict with other large procurements in PJM or MISO, and third to schedule the bid day on a Monday so that bidders would not have to hold open positions over a weekend. The IPA indicates it agrees with those recommendations and will strive to schedule the bid day accordingly. The IPA believes that the first and second principles could contradict each other, and there may not be available windows of time that do not conflict with other procurements but that are also early enough to schedule a contingency procurement.

IV. DISPUTED ISSUES

A. Fixed-Price Full-Requirements Products

1. ICEA's Position

ICEA submits that the Plan incorrectly excludes the Limited FPFR Pilot proposed by ICEA, and urges the Commission to modify the Plan to include the Limited FPFR Pilot. ICEA asserts the Limited FPFR Pilot should be included because: (1) the Plan does not sufficiently account for the Commission's Order in Docket No. 13-0546; and (2) the Plan applies the incorrect statutory standard. (ICEA Objections at 9)

ICEA reports that the Commission's Order in Docket No. 13-0546 states "a more thorough and accurate analysis" of FPFR was required in the Plan currently at issue in this docket. ICEA believes the analysis in the Plan does not go far enough beyond what was presented to the Commission in Docket No. 13-0546 that led the Commission to make this finding and require additional analysis in this Plan. (ICEA Objections at 9-10)

ICEA asserts the Limited FPFR Pilot would develop Illinois-specific analysis similar to what the Commission found to be "compelling" when undertaken in other jurisdictions. ICEA says the Limited FPFR Pilot would provide the actual, market-based data that the Commission and stakeholders need to evaluate the relative performance of FPFR against block and spot. ICEA contends instead of haggling over assumptions in speculative models or attempting to translate the experience of other states into the Illinois context, the Limited FPFR Pilot would provide four years of data to allow exploration of trends and correlations to allow for a more accurate predictive analysis. (ICEA Objections at 10)

ICEA says Plan incorrectly rejects the Limited FPFR Pilot based on what ICEA believes is a strained reading of the incorrect standard. The Plan cites Section 1-5(F) of the IPA Act to support excluding the Limited FPFR Pilot. ICEA believes the mandate in Section 1-5(F) that the IPA "continue to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time…" would be well served by a fact- and market data-based analysis of the merits of FPFR. ICEA says if the Plan relied on Section 1-5 for guidance, ICEA recommends it also rely on Section 1-5(5), in which the General Assembly found that: "The General Assembly finds and declares: . . . (5) Procuring a diverse electricity supply portfolio will ensure the lowest total cost over time for adequate, reliable, efficient, and environmentally sustainable electric service." ICEA claims adding diversity in wholesale energy products to be procured beyond blocks (managed by spot procurements) would fulfill the General Assembly's finding. (ICEA Objections at 10-11)

Without regard to Section 1-5 of the IPA Act, ICEA says the appropriate statutory standard for the Commission to review is Section 16-111.5(d)(4) of the PUA. ICEA says the Limited FPFR Pilot will fix the price of 25% of eligible retail customer load in

each of the four years it is in effect. ICEA asserts that FPFR will be no less adequate, reliable, efficient, or environmentally sustainable than block and spot procurement. ICEA believes the Limited FPFR Pilot will show the balance between affordability and price stability, although the NorthBridge Report did demonstrate that projected FPFR stacks up favorably to projected block and spot prices even under the IPA's current procurement approach. (ICEA Objections at 11)

In ICEA's view, speculative models are an inadequate substitute for actual market data that allows side-by-side comparisons of performance (and customer impact) in real-world scenarios. ICEA claims the Commission indicated its agreement in endorsing this type of analysis in other states as identified in the NorthBridge Report. (ICEA Objections at 12)

ICEA believes that the IPA and other stakeholders' skepticism that FPFR is superior to block and spot is not a reason to reject the Limited FPFR Pilot. ICEA submits that the disagreement over implementing FPFR is precisely the reason that the Commission should implement the Limited FPFR Pilot: to settle the debate. ICEA says if consensus existed, a full-blown, permanent FPFR procurement would be more appropriate than a pilot program. In recognition of, rather than in spite of, existing disagreement as to relative merits of FPFR and the IPA's current approach, ICEA urges the Commission to adopt the Limited FPFR Pilot to make a proper evaluation. ICEA also says that crediting the analysis of ICEA/NorthBridge over the Plan is not a prerequisite to approving the Limited FPFR Pilot; in fact no factual finding need be made as to the relative merits of the competing models. (ICEA Objections at 12)

ICEA wishes to highlight a few of several issues raised in its September 15 Comments, specifically with regard to the Draft Plan's analysis of market data. ICEA says the Plan's analysis of New Jersey and Pennsylvania market data in comparison to Illinois misses a key point raised by NorthBridge, namely switching risk. It is not clear to ICEA how (or if) the Plan's model accounts for switching risk in the PEA. ICEA suggests comparing Plan at 60 (explaining the calculation of "price insurance premium" in New Jersey context) and Plan at 62-63 (explaining criticisms of 2014 model by NorthBridge but not mentioning switching risk) with NorthBridge Report at 23-24 (noting that predecessor analysis to the Plan "under represents all of this [load migration] uncertainty" and inherent inaccuracies in load forecasting). ICEA states that when the effects of a declining market translate into lower competitive retail rates than the bundled rate, load shifts away from the utility causing the PEA to rise if block and spot is used - but no in-year change if FPFR is used. ICEA says under current ComEd tariffs, accumulated balances in the PEA in the current delivery year are rolled into the next delivery year's bundled rates (zeroing out the PEA accumulated balance), which leads to an effect on prices the following delivery year. In a declining market, IECA asserts this would only amplify the effect because the PEA balance would be an added cost component to bundled rates. According to ICEA, the mirror image of this effect takes place when the increasing market prices result in RES offers being above the bundled rate, resulting in self-reinforcing migration back to bundled service until the wholesale market moves enough to impact bundled rates. (ICEA Objections at 12-13)

ICEA asserts the effect noted above provides the best example of why the Plan's bottom-up approaches are not as informative of market data. ICEA says the IPA, using a block and spot approach, must purchase a number of blocks to meet an administratively preset hedging percentage based on one or two procurements in a year. In contrast, ICEA indicates FPFR bidders can make dynamic determinations about hedging strategies to support a FPFR bid. ICEA claims in times of declining market prices (where a block and spot approach might lead to increasing PEAs, which are passed along to consumers), FPFR bidders can recognize the market trend and bid lower based on a strategy of hedging relatively less than the IPA must do pursuant to a Commission Order. ICEA says while the IPA must decide on a procurement event date months in advance, FPFR bidders may buy and sell their respective hedges any day (or every day) in order to best take advantage of retail and wholesale trends. ICEA states that each bidder's hedging strategy is individualized (and confidential), so it is not possible to determine how any given supplier would bid, but the supplier group as a whole has a greater freedom to respond to market stimuli. (ICEA Objections at 13-14)

According ICEA, the result of the individualized (and not publicized) hedging strategy of FPFR bidders is that the IPA's bottom-up analysis simply cannot account for the collection of individualized bidder actions that manifest themselves as a collection of winning bids. ICEA contends the bottom-up models used previously and in the Plan seem to anticipate bidders using the exact same hedging approach as the IPA. ICEA says although nothing forecloses a bidder from using the exact same block and spot procurement strategy to back FPFR as the IPA uses, ICEA expects that virtually all bidders would take a materially different approach from the IPA and from each other. (ICEA Objections at 14)

ICEA notes the Plan cites to testimony in Pennsylvania of Scott Fisher, who authored the NorthBridge Report. ICEA says Mr. Fisher testified that the residual compensation levels cited in the Plan were reasonable, and "represent only a small portion of the winning bid prices, especially considering the other costs and risks that I described above, which FPFR suppliers intend to cover through the residual compensation to the benefit of customers." ICEA further states that the participants in the docket reached a partial settlement, which the administrative law judge recommended approving. ICEA says the partial settlement, which was supported by PECO, the consumer advocate, the small business advocate, and the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (which intervened on behalf of "economically vulnerable households"), recommended FPFR procurements for the default residential and small commercial customer classes. (ICEA Objections at 14-15)

According to ICEA, the Plan makes two basic policy arguments against including FPFR or the Limited FPFR Pilot that the Commission should reject. The first is the IPA's argument that bundled service customers do not value the insurance and stability provided by FPFR. The second is that the unique nature of IPA counsels against FPFR. (ICEA Objections at 15)

ICEA says the Plan incorrectly concludes that even attempting FPFR is inadvisable because there is insufficient demand from consumers to change from the block and spot approach. ICEA notes the Plan cites to two studies, one from Canada and one from Illinois years before any significant mass market switching, which even the Plan concedes do not definitively answer the question of what customer interest in price volatility protection is. ICEA says neither study directly addressed FPFR, the PEA, which had yet to appear in Illinois at the time of the Center for Neighborhood Technology ("CNT") survey, the relative merits of FPFR and block and spot, or any other questions relevant to the issues in this docket. According to ICEA, acknowledging the absence of evidence of customer preference either for or against FPFR, the Plan interprets the survey results and "lack of customer outcry" as support for not investigating a change in approaches. ICEA disagrees that the lack of firm evidence or "outcry" is a basis for not moving forward with a Limited FPFR Pilot. (ICEA Objections at 15-16)

ICEA agrees that the question is of balance between insurance/risk management and perceptions of lower price, but says this question is squarely for the Commission, the IPA, and stakeholders. ICEA further agrees that the Commission and IPA must strike a balance "on customers' behalf" but not on "customer outcry" or limited and attenuated survey results. (ICEA Objections at 16)

ICEA says the Plan also suggests that the IPA procurement process and that the bundled rate in Illinois is a "default" and not "provider of last resort" ("POLR") rate somehow counsels for block and spot and against FPFR. ICEA also says the Plan does not define these terms, but it appears from context that POLR is an interim service to allow customers to make their next decision while default is used to convey a standard offer. ICEA asserts that by that definition many customer classes in Illinois do have POLR instead of default rate: If any customer above 100kW in the ComEd service territory (or over 150kW in the Ameren service territory) does not choose an RES, the customer is reverted to hourly pricing. ICEA asserts FPFR is the polar opposite of the real-time pricing POLR: FPFR customers have virtually no risk of price fluctuation over the course of a supply year and do not risk constant price increases due to inaction on switching. (ICEA Objections at 16-17)

ICEA claims that by the measure above, a FPFR approach better satisfies the Plan's definition of "default" than a block and spot approach, where in June a ComEd customer will be unable to predict their rate in December closer than ± 0.5 cents/kWh (assuming ComEd keeps its voluntary PEA cap in place). ICEA says for the 2014-2015 ComEd non-summer months starting in November, the magnitude of the PEA cap (0.5 cents/kWh) is over 6.7% of the bundled supply charge. ICEA states that if ComEd ends its voluntary cap, the exposure would be significantly larger. (ICEA Objections at 17)

According to ICEA, the Draft Plan also relies on an unsupported contrast between Illinois and other restructured states to justify not including FPFR. On one hand ICEA appreciates the clarification in the filed Plan from the Draft Plan for Public

Comment, which suggested that all other restructured states that used FPFR in whole or in part had POLR (rather than default) service. ICEA says filed Plan continues to equate FPFR with POLR, a connection that the filed Plan does not explain or support. ICEA asserts the filed Plan does not explain why the FPFR-supported bundled products in, for instance, Connecticut, Delaware, Maryland, New Jersey, Pennsylvania, and Washington, D.C. are “POLR” and not “default.” Accepting *arguendo* that Illinois utilities for which the IPA procures should provide default service, and not POLR service, ICEA complains the filed Plan provides no reason that block and spot procurements better achieve the goals of default service. (ICEA Objections at 17-18)

ICEA requests that the Commission adopt the Limited FPFR Pilot within the ComEd service territory to compare the performance of the IPA’s existing (and ongoing) block and spot procurements against actual IPA-run FPFR procurements. ICEA claims this data will allow for exactly the comparison that the Commission found to be “compelling” in the NorthBridge Report, except that it will generate Illinois-specific data for execution under Illinois’ statutory and regulatory scheme. ICEA believes four years of data will allow the Commission to make a fact-based determination using actual market data as to whether FPFR best meets the requirement of Section 16-111.5(d)(4) of the PUA, the standard for the Commission approving the procurement plan. (ICEA Objections at 6)

The specific product that ICEA recommends that the IPA procure is based on the presentation delivered to the June 5, 2014 IPA Workshop on FPFR products ("the ICEA Presentation"), as clarified in the IPA’s comments to the IPA’s subsequent Request for Comments ("the FPFR Comments"). ICEA says the general concept is that market-based charges, such as energy and ancillary services, are included in the product, while non-market based charges are not. ICEA states that although capacity ("peak load contribution," or "PLC") and network services transmission ("network services peak load," or "NSPL") are market based, ICEA recommends that these PJM allocated peak load related costs be excluded because ComEd has already committed to unbundling at the wholesale level and may end up unbundling retail rates in the future. (ICEA Objections at 6-7)

Recognizing that the FPFR purchase is part of a limited pilot during which block and spot purchases will continue, ICEA proposes that the IPA integrate the two by separating out FPFR tranches from the block and spot tranche. In other words, if FPFR is procured for 20% of the portfolio, block and spot (both past and contemporary procurements) would be used to address 80%. ICEA says if at a given hour demand by eligible retail customers is 5,000 MW, using the same percentages the FPFR suppliers collectively would be responsible for 1,000 MW of supply, while the utilities would balance supply under contract with 4,000 MW of demand using the spot market. To describe further, ICEA says if the IPA had procured 3,500 MW for that particular time period, the utility would have to balance by buying 500 MW; if the IPA had procured 5,500 MW, the utility would balance by selling 1,500 MW. ICEA states that even though all eligible retail customers would see one single rate (with a PEA), the Commission, the IPA, Staff, and stakeholders will be able to see how the block and spot approach

compares with the FPFR approach with a backward-looking analysis of the sum of those transactions over the course of the year. (ICEA Objections at 7-8)

ICEA recommends that the 2015 Plan filed with the Commission authorize a 25% tranche of the total load to go to FPFR each of the four years, with FPFR procured as a one-year product while the blocks are procured in the same laddered manner. ICEA insists this will allow an apples-to-apples comparison, and should function for the duration of the pilot because the IPA aims to have 50% of supply needs under contract going into the last procurement before the delivery year. (ICEA Objections at 8)

ICEA is heartened to see that although the Plan did not recommend the Limited FPFR Pilot, the Plan also did not identify any barriers to implementation should the Commission order the IPA to undertake the Limited FPFR Pilot. The IPA identified a $850,000 "initial set up" with the IPA's Procurement Administrator, NERA. ICEA understands that NERA has significant experience in FPFR procurements in other jurisdictions, and further understands that NERA has a long-standing relationship with the IPA. This combined experience leads ICEA to believe that NERA will quickly and efficiently develop FPFR standard contracts. (ICEA Objections at 8)

ICEA believes RESA and Exelon present well-supported arguments that the Plan does not sufficiently support its rejection of the Limited FPFR Pilot. Although ICEA wishes to clarify that it does believe findings regarding competing models is necessary for a Commission decision adding ICEA's Limited FPFR Pilot, ICEA agrees with RESA and Exelon's additional support. (ICEA Response at 3)

ICEA says CUB is the only party that supported the Plan's failure to adopt the Limited FPFR Pilot. ICEA believes by and large, CUB does not raise any new arguments. CUB does state: "individual consumers and municipalities have the option to choose price stability by selecting an alternative retail electric supplier, one could argue that remaining eligible retail customers are less likely to prefer a risk premium." ICEA also says CUB does not appear to have conducted a study or otherwise provided data to support this conclusion. ICEA maintains that the Commission, the IPA, and stakeholders must determine the proper level of rate stability for customers, rather than rely on outside factors. ICEA asserts customers who want relatively less price stability than would be present in a default product backed by a partial or full FPFR procurement would provide would still be able to acquire a variable-rate ARES product or utility real-time pricing options. (ICEA Response at 3-4)

The IPA states that the number of customers taking service from an alternative supplier peaked in March 2014 at 3,108,442, but by August had fallen to 2,808,916. The IPA believes this may be evidence that the current IPA procurement strategy is successful, and is not in need of being fixed.

ICEA is concerned that the IPA's resistance to the Limited FPFR Pilot is based on a misconception of the IPA's core mission. ICEA claims that at its essence, the

IPA's role is to conduct transparent procurements that allow bundled utility customers to reap benefits from a competitive wholesale market. ICEA says the Plan explicitly acknowledges this, quoting Section 1-5(G) of the IPA Act; and that Sections 1-5(B), (E), and (F) support this understanding of the IPA's role as well. ICEA asserts that nowhere does the IPA Act or the PUA suggest that a measure of the IPA's success is the bundled product's market share. ICEA contends that not only would such a goal be unsupported by statute, but it would also run counter to the Commission's longstanding policy favoring retail competition. In ICEA's view: the IPA Act and the PUA make clear that the IPA's role is to be an efficient, transparent and independent administrator of procurements in translating wholesale competition to bundled customer retail benefits. ICEA says customer migration to RES service from the IPA-procured default product was not an indictment of the IPA's procurement strategy. ICEA also says, customer return to bundled service may be a reflection of market conditions, but does not provide evidence of the advisability of the block and spot approach, or whether the block and spot approach best satisfies Section 16-111.5(d)(4) of the PUA. (ICEA Reply at 3-4)

ICEA claims one of the core arguments in favor for FPFR generally is that FPFR procurements allow utility service customers to benefit from wholesale competition while insulating customers from price fluctuations inherent in the block and spot approach. ICEA contends that contrary to the IPA's argument that ICEA and other parties have presented "mere speculation about potential benefits" of FPFR, parties have provided substantial evidence that there are great potential benefits to customers. ICEA says it does not ask that the Commission take ICEA's word for it; ICEA says it recommends the Limited FPFR Pilot to quantify the costs and benefits with actual market data. (ICEA Reply at 4)

ICEA says although the IPA's Response devotes substantial pages to opposition to ICEA's Limited FPFR Pilot and FPFR generally, the IPA's Response does not provide sufficient bases for excluding the Limited FPFR Pilot from the Draft Plan. ICEA maintains that the Commission does not need to find that an FPFR approach would have a lower cost than a block and spot approach to order the Limited FPFR Pilot. (ICEA Reply at 5)

ICEA disagrees with CUB that the Limited FPFR Pilot would not provide some additional degree of price stability, claiming there will be virtually no, if any, PEA for the FPFR component. ICEA believes that the value of the pilot program goes far beyond the price stability or other beneficial effects of FPFR procurements during the limited pilot. (ICEA Reply at 5-6)

In light of what ICEA sees as the narrow scope of relevant information to the Commission's inquiry, ICEA says it did not overload its Objections with specific criticisms of the Plan analysis that ICEA claims it laid out in significant detail in its September 15, 2015 Public Comments ("ICEA September Comments"). ICEA says it only pursues its Objections to the extent the Commission believes factual or legal resolutions are necessary to adopt the Limited FPFR Pilot. Though ICEA continues to believe it is not relevant to the adoption of the Limited FPFR Pilot, ICEA says it

addresses the IPA's contentions that the IPA's new research has properly addressed switching risk. (ICEA Reply at 6)

The IPA summarizes its conclusions from the new research with its statement that: "[b]y trading maximum price impact for maximum stability, full requirements procurement fails to balance competing goals." ICEA says the IPA only analyzes a 100% FPFR procurement, which no party in this docket advocates, against its current approach, without any discussion as to whether FPFR would be appropriate in any percentage as a hedge. ICEA states that other states use both FPFR and block and spot together, a possibility that the Plan analysis does not discuss. ICEA claims it has demonstrated that notion of "maximal price" for "maximal stability" is factually incorrect. ICEA asserts that although it disputed the Plan's characterization of how often such circumstances would occur, there is no dispute that a 100% FPFR approach would be expected to produce a lower price to end-use customers under some circumstances. ICEA claims it presented substantial evidence that the price insurance provides value for consumers in that their electric rates are guaranteed not to fluctuate higher with little advance notice during the course of a year. (ICEA Reply at 6-7)

With regard to whether the IPA's new research is unrefuted, ICEA says it did critique the analysis in ICEA's September Comments. ICEA asserts that although the ICEA September Comments referred to the Draft Plan for Public Comment dated August 15, 2014, its critiques are equally applicable to the Draft Plan. ICEA argues that:

- The Plan does not adequately account for the value of insurance, specifically price insurance that FPFR provides. Instead, the Plan simply compares an expected price of FPFR with an expected price of block and spot and calls the difference the "premium."
- Even accepting the Plan's approach to a "premium," the average "premium" in New Jersey from 2002 through the NorthBridge Report is $3 MWH, or about 3% of the overall product price. The Plan appeared to cherry pick recent years. (ICEA Reply at 7)

ICEA claims it critiqued the Plan's failure to analyze switching risk as part of its investigation of "premia." In the IPA's Response, ICEA says there is no analysis or explanation of how the Plan approached switching risk in analyzing "premia." Instead of explaining how the IPA's model addressed switching risk, ICEA complains the IPA's Response instead makes arguments that switching risk is adequately addressed in the IPA's procurement approach. With regard to the latter, ICEA says the Limited FPFR Pilot will measure how costs of switching risk are handled by each method. With regard to the former, ICEA claims its critique of the IPA's accounting for switching risk in its modeling and observation remains unrefuted while the Plan's new research is not uncontested. (ICEA Reply at 7-8)

ICEA maintains that the Plan likely did not meet the bar set by the Commission's Final Order in Docket No. 13-0546 for responsive analysis. ICEA says the plan

included analyses of three-year products in New Jersey without any discussion of less than 100% FPFR and without any discussion of switching risk. In ICEA's view, these exclusions from the Plan call into question how "thorough" and "accurate" the Plan's analysis is, and whether it compares ICEA's Limited FPFR Pilot apples-to-apples. (ICEA Reply at 8)

ICEA asserts that without regard to whether the Commission credits the NorthBridge and ICEA analysis or the Plan analysis more, the best way forward is to settle the dispute with actual data by ordering IPA to conduct the Limited FPFR Pilot. ICEA claims working with a common data set and with Illinois-specific data, the Commission, IPA, and other stakeholders will be able to continue a data- and evidence-based discussion of FPFR and its appropriate place in IPA procurements. ICEA believes a Commission decision to approve the Limited FPFR Pilot would be well founded based on the evidence in the record. (ICEA Reply at 8-9)

Although the IPA does not recommend the Commission adopt ICEA's Limited FPFR Pilot, the IPA provided substantive comments on implementation of the Limited FPFR Pilot or a substantially similar program. ICEA appreciates the IPA's willingness to address implementation issues while maintaining its litigation position. (ICEA Reply at 9)

The IPA raises an issue with regard to its budget and the ability to pay for its Procurement Administrator to draft standard contracts. Although ICEA believes that a Limited FPFR Pilot should start immediately all matters being equal, ICEA does understand that limited budgets provide a roadblock. Provided that the IPA agrees to, or is ordered to, begin work immediately and with all due haste once additional funds are available in FY16, ICEA would not object to delaying the first procurement. (ICEA Reply at 9)

The IPA argues that questions about the goals of the Limited FPFR Pilot "must be first answered" before approving the Limited FPFR Pilot. ICEA agrees that there should be discussion of research questions both in advance and as the Limited FPFR Pilot is unfolding. ICEA says it has positions on all of the IPA's questions, but believes it would be more fruitful to handle these questions in workshops of defined length ordered by the Commission. In light of the IPA's request to begin work on the procurement in the next state fiscal year, ICEA believes there will be ample time to get input from stakeholders about the proper questions and monitoring of data. (ICEA Reply at 9)

In order to begin the dialogue, ICEA recommends at minimum the data collected include the aggregate effects on eligible retail customers of blocks plus the effect of the sum total of all spot procurements. ICEA says this data should be reviewed in light of, at minimum: (1) the published Price to Compare versus RES offers for individual switching and aggregation, (2) actual switching patterns, (3) trends in the wholesale spot and forward markets leading up to each procurement and during the delivery year, and (4) analysis of deviations in actual load from the load forecast (including weather and switching). (ICEA Reply at 10)

The IPA appears to be requesting that a Limited FPFR Pilot provide some assurance that retail prices not exceed the retail prices that would have hypothetically been paid using a block and spot approach. ICEA strongly opposes this recommendation. According to ICEA, the point of the Limited FPFR Pilot is to determine how FPFR performs against a three-year laddered block and spot approach using actual market data. ICEA says if prices go up, including due to the block and spot costs passed on to consumers, relative to the competitive retail market, customers will be free to choose utility real-time pricing, a product in the competitive retail market that best reflects the customer's preferences. (ICEA Reply at 10)

The IPA analogizes to the AMI pilot, but ICEA believes this comparison is inapposite. ICEA says in the AMI deployment pilot, some customers were put on different rates from other customers, which may have led to higher (or lower) charges to the customer than the customer would have otherwise faced if on the default rate. (ICEA Reply at 10-11)

In ICEA's view, ComEd and the Commission had a legitimate research purpose for having a control group whose rates were changed and monitored for savings based on "education." ICEA says ComEd also had the tools to determine how the customers on a dynamic rate would have been charged under a flat rate (with PEA). ICEA states that in the context of a Limited FPFR Pilot, all utility customers would be subject to the same rates, and there will be no way to tell what the cost would have been if the 25% FPFR component in the immediate year was instead procured under block and spot approach. (ICEA Reply at 11)

ICEA asserts that as a corollary, use of an imagined "hold harmless" amount would subject successful Limited FPFR Pilot bidders to significant risk with no compensating value. ICEA says ComEd is generally entitled to recover its just and reasonable costs, and there is no evidence that in the AMI pilot ComEd was forced to forego recovery of just and reasonable costs by "holding harmless" the pilot program customers. ICEA states in contrast, successful Limited FPFR Bidders are not entitled to collect shortfalls of expected revenue, as a general matter, this is precisely the value of holding a competitive procurement for a FPFR product. ICEA says without the ability to make up shortfalls and bids arbitrarily capped at the "hold harmless" amount, ICEA would expect a significant chilling effect on bids. ICEA contends the benchmark required by Section 16-111.5(e)(3) of the PUA that must be applied to all competitive IPA procurements will ensure that bids are sufficiently reflective of market conditions and the value added. (ICEA Reply at 11)

The IPA raises a similar concern in its Response when it argues: "there is no 'treatment group' of customers receiving pricing based on fixed-price full requirements contracts, and no 'control group' receiving pricing based on the IPA's normal purchase strategy." ICEA states that the analysis the Commission found to be "compelling" in the PECO service territory did not, to ICEA's knowledge, include any control group of customers. ICEA maintains the Limited FPFR Pilot would develop Illinois-specific

analysis similar to what the Commission found to be compelling when undertaken in other jurisdictions. ICEA claims the Limited FPFR Pilot is about the effects of wholesale procurements on retail rates, an experiment that it believes requires side-by-side procurements, not a "control group" of retail customers. (ICEA Reply at 11-12)

Although ICEA proposed a Limited FPFR Pilot for the ComEd service territory only, the IPA recommends adding in the Ameren service territory as well. ICEA acknowledges the IPA's argument that PJM and MISO markets may be different, but ICEA for now only proposes testing in the ComEd/PJM market. ICEA reserves the right to propose a program substantially similar to the Limited FPFR Pilot in the Ameren service territory at a future date, but declines to do so at this time. ICEA suggests the IPA's argument about the potential differences between PJM and MISO could be duly noted in any conclusions from the ComEd-based Limited FPFR Pilot. (ICEA Reply at 12)

The IPA poses the question as to the appropriate size of the proper volume of FPFR procurement in any pilot while simultaneously suggesting that 25% of load is "not a pilot." ICEA asserts the size is sufficient to have multiple winning bidders. ICEA understands that in order for any procurement to work to its fullest, it must be competitive. ICEA says in part, the 25% of load value was to allow for multiple tranches to be awarded, thus attracting a wide range of potential suppliers. ICEA notes that making multiple tranches available diminishes the risk that results will be skewed by a single outlying bidder in any given year. (ICEA Reply at 12-13)

ICEA claims the size is sufficiently small so as to allow for three years of block and spot procurement. At the same time, in order to be a true pilot program for comparing market data, ICEA wished to balance the FPFR component of the procurement with the immediate year blocks. In this way, ICEA says the block and spot component shows the effects of a laddered approach (with spot procurements) versus an immediate-year FPFR approach. (ICEA Reply at 13)

ICEA believes the appropriate balance of these two factors is 25% FPFR. ICEA notes that neither the IPA nor any other party discussed the relative merits of a pilot program with a greater or lesser percentage of FPFR, either from a rate impact or data development standpoint. (ICEA Reply at 13)

The IPA argues: "As the IPA strongly believes that requiring any level of switching to full requirements procurement has not been adequately justified, it is certainly not justified for half of the IPA's procurement goal." ICEA says the IPA means that the immediate year procurement would be reduced by less than half for July and August and about half for other months. ICEA complains that the IPA does not provide an alternative proposal, instead opting only for opposition. ICEA says without any evidence from other parties about a more reasonable FPFR procurement percentage, ICEA recommends maintaining the Limited FPFR Pilot at 25% of total eligible retail customer load to be procured in the prompt year. (ICEA Reply at 13)

ICEA is confused by the IPA's question about "statistically meaningful results." ICEA believes this is mostly a product of the number of years studied (reducing the impact of a year with abnormal market fluctuations) rather than procurement percentages. If the IPA proposes additional years to gather market data, ICEA would be amenable to discussing an extended pilot. ICEA believes 75% of procurement from a laddered block and spot approach (with roughly one third procured per year) and 25% in immediate year FPFR should be sufficient on both sides to show the price effects of both. (ICEA Reply at 13)

The AG states that "many" of the parties favoring the Limited FPFR Pilot are suppliers that "primarily offer . . . FPFR contracts to their customers." The AG makes a similar argument with regard to diversity of procurement options, stating that the choice between FPFR and block and spot-procured products "is the essence of a competitive market." ICEA suggests that the AG is missing the point of the competitive retail market. ICEA says while it may be true that RES in Illinois offer many fixed price products, RES also offer a range of other products and look to expand dynamic-rate products going forward. ICEA asserts customers focus on the price, value added, and other features, rather than the procurement (wholesale) approach used to procure the product. In ICEA's view, the fact that multiple suppliers offer fixed price products, over a variety of different time periods with a range of other benefits, is not a reason that the Limited FPFR Pilot would not provide valuable data. ICEA claims because the utilities must offer a product with a summer and non-summer rate for one year and cannot offer other value added, a full FPFR procurement may provide significant price and price stability value. ICEA says both are without regard to the number of fixed price products marketed (as identified by the AG) or sold by RES. (ICEA Reply at 14)

The AG states: "it is prudent for the IPA to continue to use a procurement method other than the one used by most suppliers to preserve procurement options available to consumers." ICEA maintains although underlying wholesale procurement approaches may be associated with different retail products, customers choose retail products, not wholesale procurement approaches. Although ICEA is not aware of the exact procurement approaches used by its membership or other RES, ICEA does note that not every fixed price product on the retail market has the same price, offers the same terms and conditions, or has the same value added. ICEA states that whether the Limited FPFR Pilot or a full-scale FPFR procurement, bundled customers would see the same retail rate structure, except that perhaps the PEA would be muted to the extent that FPFR is a larger share of the procurement. (ICEA Reply at 14-15)

The AG argued that the PEA has gone from a charge to a credit. The AG states that "ICEA, RESA, and Exelon did not rely on issues related to the PEA in their objections or cite the operations of the PEA as a reason to adopt FPFR procurement." ICEA says although it and other parties have historically identified problems with the PEA for customers whether the PEA is a charge or credit, ICEA has provided many other well-founded bases other than the PEA for implementing a Limited FPFR Pilot. ICEA claims the one cent band within which the ComEd PEA may sit in any given

month provides significant uncertainty to customers that make choosing the appropriate product for their individual preferences much more difficult. (ICEA Reply at 15)

The AG also argued that there should not be a change in procurement strategy as U.S. EPA greenhouse gas regulations are being developed and implemented. ICEA says that this is a *non sequitur*. ICEA states although the IPA does enter into unit-specific contracts in very limited circumstances (which have often increased prices for customers), neither the IPA's current block and spot strategy nor FPFR are unit-specific. ICEA says nobody (except perhaps winning suppliers) knows the fuel mix, emission profile, or even the state of origin of the block power purchased by the IPA or by utilities to balance load. To the extent that "[t]he new rules combined with how the Illinois General Assembly decides to address the state and market issues raised by the rules" has some effect on energy markets, ICEA claims the AG presents no evidence as to why this would confound the data analysis of ICEA's proposed Limited FPFR Pilot. (ICEA Reply at 15-16)

The AG disputes that "the IPA procurement strategy is stagnant or rigid," arguing that the IPA engages in "active portfolio management." ICEA says this is true to a certain extent; the IPA has recommended multiple procurements and 106% hedging in summer months. ICEA asserts the IPA does not and cannot "actively" manage its portfolio in the sense that its procurements are at set time(s) of the year and for pre-approved amounts based on utility load forecasts. ICEA suggests supposing the IPA had already conducted its scheduled Spring 2015 procurement and on June 2 realized that it was under-hedged for July and August and eligible retail customers would benefit from buying extra supply on that day due to market trends. ICEA says the IPA could not simply go to the market and buy that extra supply. ICEA states that Ameren and ComEd would have to balance in the day-ahead market (with no IPA involvement), whether or not consumers would have been better off by a forward-looking purchase on June 2. ICEA says customers may face higher charges based on this rigidity, which would be expressed through the PEA. ICEA states that with FPFR, a supplier would not be able to change its bid price if on June 2 it realized it was under hedged and needed to buy more supply at less favorable rates. ICEA says the supplier would be responsible for making the wholesale transactions necessary to provide service at the rate the suppliers successfully bid. (ICEA Reply at 16)

The AG states that "To date, the competing procurement strategies of the IPA and the other suppliers have resulted in a vibrant competitive market and extensive municipal aggregation." ICEA agrees that municipal aggregation and individual switching have led to a vibrant competitive retail market in which customers have both saved money and found added value. ICEA maintains there is no evidence that the Limited FPFR Pilot or a full-scale FPFR procurement for utility bundled service would harm the vibrant retail competitive market. (ICEA Reply at 16-17)

In its Brief on Exceptions, ICEA indicates that it continues to believe that there is sufficient evidence in the record to support the Commission including the Limited FPFR Pilot in the 2015 Procurement Plan. In the event the Commission believes there is not

enough evidence in this proceeding to order the implementation of its pilot program, ICEA offers two alternatives. First, ICEA says the Commission could encourage the filing of a petition for rehearing on the issue of FPFR products, which, if granted, would allow for an additional five months to review the evidence. Second, ICEA suggests the Commission could direct stakeholders to discuss and come prepared to the next procurement plan proceeding with implementation proposals. ICEA says it offers these potential solutions in the spirit of compromise and hopes that stakeholders will be willing to further engage with ICEA and other Limited FPFR Pilot proponents in between the Final Order in this docket and the next procurement plan approval docket. (ICEA BOE at 10-11)

It appears to ICEA that the IPA recommends that the Commission order ICEA not to make certain arguments in future Procurement Plan approval dockets, including those related to the NorthBridge Report and the analysis the IPA conducted for the first time in the present docket. ICEA objects to such a proposal. ICEA states that as a general matter, Commission Orders do not have *res judicata* effect. ICEA believes the relief apparently requested by the IPA would frustrate the Commission's longstanding approach by potentially giving its decision regarding the Limited FPFR Pilot and specific data-driven backward looking comparisons of market data *stare decisis* or *res judicata* effect. ICEA asserts closing the door on ICEA's proposal and analysis as presented in this docket for all future dockets would frustrate the purpose and structure of the Commission. (ICEA RBOE at 3-4)

ICEA says although it sympathizes with the IPA's concerns regarding litigation and expert costs, ICEA believes that the IPA's concerns are somewhat misplaced in this case. As ICEA understands it, if the Commission were to request further analysis of FPFR or the Limited FPFR Pilot in next year's plan that required outside expert help, the IPA would have sufficient time to include those costs in its FY16 appropriation request. ICEA further understands that, once appropriated, the IPA's costs are recoverable either from participating utilities or bidders in procurements—and will not burden the state's General Revenue Fund. ICEA is also unaware of the IPA hiring any experts in addition to PA Consulting, which serves as the Procurement Planning Consultant that the IPA must hire by statute.

2. RESA's Position

RESA recommends that the Commission revise the 2015 Procurement Plan to include a four-year pilot program to incorporate FPFR products in the energy procurements for ComEd. (RESA Objections at 2, Response at 3)

RESA believes the IPA's analysis of FPFR products supporting its decision to exclude such products from the 2015 Procurement Plan is flawed. RESA claims the only valid means to compare FPFR products against the IPA's continued use of a three-year ladder of block and spot purchases is to use the four years of pilot program data to make such a comparison. Absent the pilot program and absent such a comparison, RESA says the IPA's conclusions that led to its decision to exclude FPFR products from

the 2015 Procurement Plan are not based on fact, but on speculation. (RESA Objections at 2, Response at 3)

In support of its proposed procurement strategy, the IPA states that it believes that its continued use of a three-year laddered block and spot 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 claims the IPA's recommended electric supply procurement strategy, which it characterizes as 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 unforeseen costs captured in the Purchased Electricity Adjustment. RESA contends 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 3)

RESA states that the Commission in its Order in Docket No. 13-0546 approving the IPA's Procurement Plan for 2014-2015, noted numerous shortcomings of the IPA's analysis of FPFR products. Because of these shortcomings, the Commission directed the IPA to do a more complete and robust analysis of FPFR products. RESA argues that the 2015 Draft Plan, and accordingly the 2015 Procurement Plan (because it did not deviate substantially from the 2015 Draft Plan on this issue), relied heavily on the analysis used by ICEA in its 2014 Procurement Plan and, therefore, fails to provide the complete and robust analysis of FPFR products desired by the Commission. (RESA Objections at 4)

RESA contends that contrary to the conclusion of the IPA, the premium reflected in the pricing of FPFR products is reasonable and justified when compared to the much greater magnitude of rate shock under the block and spot approach used by the IPA. RESA claims the two surveys relied upon by the IPA for its conclusion that Illinois customers are not willing to pay a premium for FPFR products do not support that conclusion. (RESA Objections at 4)

RESA says the 2015 Procurement Plan contains two substantive additions to the 2015 Draft Plan. First, the IPA added Subsection 6.6.2.6 to address its estimated costs of implementing a FPFR procurement. Second, new Subsection 6.6.3 addresses ICEA's proposed four-year pilot program. RESA believes neither of these additions adds merit to the IPA's rejection of FPFR products. (RESA Objections at 4)

RESA states that for the first time, the IPA, in the 2015 Procurement Plan, offers an estimate, as requested by the Commission, of the initial set up cost of a FPFR procurement, $850,000. RESA says that estimate is for both Ameren and ComEd and ICEA's pilot program is only proposed for ComEd, which, according to the IPA, would

cut this estimate by 25%-30%. According to RESA, there is no break-down of this cost, but the IPA notes that many matters would need to be addressed in order to implement a FPFR procurement, including "the development of contract and credit forms tailored to the product," "the compilation of data with the assistance of the utilities sufficient for bidders to evaluate the opportunity," and the "response to bidder questions that may include inquiries about PJM and MISO developments." RESA maintains that ICEA's pilot program is limited to ComEd's service territory, which would eliminate inquiries about developments in MISO. RESA also suggests the IPA has a great deal of experience in procurement matters and with that experience, RESA does not believe that a cost ranging from $595,000 to $637,500 (which in RESA's view does not appear to be enormous considering the overall costs of procurement of energy in Illinois) has been substantiated. (RESA Objections at 5)

RESA claims that in a new subsection, Subsection 6.6.3, the IPA "summarily rejects" the four-year Pilot Program detailed in ICEA's Comments on the Draft Plan. The purpose of the pilot program, as stated by ICEA and quoted by the IPA in its 2015 Procurement Plan, is "to compare the performance of the IPA's existing (and ongoing) block and spot procurements against actual IPA-run FPFR procurements." According to ICEA, four years of data will allow the Commission to make a fact-based determination using actual market data as to whether FPFR best meets the requirement of Section 16-111.5(d)(4) of the PUA, the standard for the Commission approving the procurement plan. (RESA Objections at 5-6)

RESA says the IPA rejects the four-year pilot, apparently confident that "its extensive analysis" demonstrates that the block and spot approach achieves the goal of providing the lowest total cost over time, taking into account any benefits of price stability. RESA asserts the IPA's confidence in its extensive analysis is misplaced, that its analysis is flawed, and does not justify rejection of ICEA's pilot program. (RESA Objections at 6)

RESA also says the IPA downplays the need for actual data as the "desire" on the part of some parties "to have more information about full requirements procurement that cannot be captured by studying those states or by conducting additional simulations of rate impacts." RESA reports that the IPA concludes that while a pilot program may provide new data, it would fail to provide "the lowest total cost over time, taking into account any benefits of price stability." RESA believes the IPA completely misses the point. RESA says the pilot program will allow the Commission and its Staff, the IPA, and stakeholders to see how the IPA's block and spot approach compares with the FPFR approach by making available a backward-looking analysis of the sum of actual transactions over the course of the year. RESA argues this will allow the Commission to make a fact-based apples-to-apples comparison of the block and spot approach and the FPFR approach. RESA says the Commission can determine whether the FPFR approach would provide the lowest total cost over time, taking into account any benefits of price stability. RESA states that if the Commission makes this determination, it can expand the use of FPFR products in future procurements. (RESA Objections at 6-7)

RESA agrees with ICEA that the two policy arguments raised by the IPA against FPFR products should be rejected. RESA asserts there is not sufficient evidence that bundled service customers would not value the insurance and stability provided by FPFR products. RESA also claims there is nothing about the IPA's role, as set forth in the IPA Act that supports the rejection of FPFR products. (RESA Response at 4)

CUB was the only party to file Objections which supported the IPA's exclusion of FPFR products from the 2015 Plan. RESA says CUB's rationale basically agrees with the IPA's arguments as set forth in the 2015 Plan. RESA claims all of those arguments have been refuted in the Objections of ICEA, Exelon and RESA. However, RESA would like to address one of CUB's statements: "CUB agrees [with the IPA] that any benefits of price stability associated with full requirements are, at this time, unknowable." RESA asserts that is exactly the purpose of the ICEA Pilot Program, to provide actual data which would allow an apples-to-apples comparison of FPFR products with the IPA's block and spot approach. RESA contends that absent that pilot and that comparison, CUB, and the IPA are rejecting, out-of-hand, a potential superior alternative to the block and spot approach. (RESA Response at 4-5)

RESA says Exelon makes the observation, with which RESA agrees, that the fact that the benefits of price stability have not been fully explored in Illinois is not a reason to reject the ICEA Pilot Program. RESA contends it is precisely the reason that the Commission should adopt the ICEA Pilot Program. (RESA Reply at 3)

Staff states that it disagrees with one of the arguments made by CUB against the ICEA Pilot Program - that a pilot program will not, in its own right, provide price stability for Illinois consumers. Staff states that CUB's criticism overlooks the value of conducting a pilot program, namely providing a side-by-side comparison between the bidding results of a FPFR procurement and the IPA's block and spot procurement, conducted nearly simultaneously and for the same delivery periods. According to Staff, such experiments would provide additional relevant data on the relative cost of the two procurement approaches.

RESA agrees with Staff on this point. RESA says the purpose of the ICEA Pilot Program is to provide actual data which would allow an apples-to-apples comparison of FPFR products with the IPA's block and spot approach. RESA asserts that in addition to cost considerations, such a comparison would also allow an evaluation of the benefits derived from these two product procurements.

RESA says the AG admits that its first argument is in response to a position that neither ICEA nor any other party supporting the ICEA Pilot Program made with respect to the 2015 Plan—the impact of the electric utilities' PEA on the ability to achieve an accurate Price-to-Compare. RESA says it is unsure why the AG raises an argument that is supported by no party to these proceedings, and therefore may not be relevant to the issues at hand. RESA suggests if this is a relevant argument, then it also raises the question whether a block and spot product similarly impacts utilities' PEAs and the ability to achieve a meaningful Price-to-Compare. RESA does agree with the AG on

this point and says this was not an argument made in support of the ICEA Pilot Program. (RESA Reply at 4-5)

The AG argues that the Commission should not adopt the ICEA Pilot Program because of potential changes in the energy supply market due to the United States Environmental Protection Agency's draft rules regarding carbon emissions. RESA suggests that the potential impact of these draft carbon emissions rules could possibly be greater in circumstances where the IPA procures only one product type that buys blocks at only one point in time and fills in with monthly spot purchases. In RESA's view, the ICEA Pilot Program could prove to provide greater price stability than the current block and spot product during times of increased price volatility. RESA does not see any negative impact of those draft rules on the merit and benefit of the ICEA Pilot Program. (RESA Reply at 5)

The AG also argues that proponents of FPFR products ignore the value of utilizing multiple procurement strategies and preserving options for customers. RESA believes the AG misses the point. RESA asserts the ICEA Pilot Program will not replace the IPA's traditional procurement of block and spot purchases; the two will co-exist for comparison purposes. RESA says the two will operate side-by-side in order to determine which approach is superior for customers from both cost, and benefit, perspectives. (RESA Reply at 5)

The AG argues that the IPA has successfully exercised flexibility and discretion in managing its procurement. RESA does not see the ICEA Pilot Program as an attack on the IPA. RESA maintains the purpose of the ICEA Pilot Program is to provide a comparison, currently lacking, of the results of largely simultaneous procurements of FPFR products and block and spot purchases. (RESA Reply at 5)

The AG argues the Commission should resist the argument that there is only one "best" way to obtain electric supply. RESA is not sure who is making such an argument; RESA says it has never argued that there is only one best way to obtain electric supply. RESA states that since the first procurement in 2008, the IPA has only procured one type of electric supply product; the AG's argument goes against those who would preclude the IPA from exploring other product types, like the FPFR product suggested by ICEA's Pilot Program. RESA repeats that the ICEA Pilot Program would not supplant the IPA's block and spot approach. RESA says the two procurement approaches would operate at the same time in order to provide a meaningful comparison. (RESA Reply at 6)

The IPA argues that its current procurement approach produces the lowest total cost over time, taking into account any benefits of price stability. RESA claims that this is an opinion, not a fact. RESA says it is not an opinion based on experience gained through a comparison of two product procurements conducted at the same time which is what RESA urges the Commission to approve. Absent conducting the ICEA Pilot Program, RESA contends it will remain an opinion based on subjective analysis, not on facts. (RESA Reply at 6)

The IPA argues that is has fully complied with the Commission's directive in its order in Docket No.13-0546 to include a more thorough and accurate analysis of the impacts of incorporating FPFR products into its procurement strategy. RESA believes that its Objections, and the Objections of ICEA and Exelon, demonstrate that the IPA has not provided the thorough and accurate analysis demanded by the Commission in its Order in Docket No.13-0546. (RESA Reply at 7)

The IPA offered several criticisms of the NorthBridge Report, sponsored by ICEA in Docket No. 13-0456 and attached to its Objections in this proceeding, noting that it withheld raising those criticisms last year. RESA will leave it to ICEA to support the NorthBridge Report against the IPA's belated criticisms since ICEA sponsored the report. However, RESA states that not only did the IPA withhold its criticisms of the NorthBridge Report last year, RESA presumes that in Docket No. 13-0546 it also withheld these criticisms during the processes leading up to its filing of the 2015 Plan, including its June 4, 2014 workshop and the draft plan it published on August 15, 2014. In RESA's opinion, the IPA's withholding of criticisms is contrary to the Commission's desire for a thorough and accurate analysis based on the merits of the proposed change. (RESA Reply at 7-8)

In it Reply Brief on Exceptions, RESA states while it prefers ICEA's primary position, approval of the ICEA pilot program in the Commission's final order in this proceeding, or the first alternative presented in ICEA's Brief on Exceptions, provide further consideration to the pilot program on rehearing, ICEA's second alternative is, once again, a better alternative than outright rejection of the pilot program. (RESA RBOE at 3)

The IPA asks the Commission to amend the Proposed Order to provide that it will no longer consider proposals for procurement of FPFR products, except in the event that the IPA itself makes such a proposal. RESA believes it is inappropriate for the IPA to attempt to tie the hands of future Commissions in the Order in this proceeding. RESA says the entire principle that Commission decisions are not *stare decisis* is not to bind future Commissions to the decisions of prior Commissions. Instead, RESA says each case must be determined on its merits. (RESA RBOE at 4)

3. Exelon's Position

Exelon 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. To that end, it supported the ICEA filing on the 2014 Plan, which included a comprehensive study and report by the NorthBridge Group. Exelon reports that in the Order in that case, the Commission remarked that certain findings in the NorthBridge Report were "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." Exelon notes the Commission ultimately chose not to adopt a full

requirements product as part of last year's Plan, largely as a result of discomfort with the level of review and feedback provided by other parties, and the limited time frame that the Commission itself had available to review the NorthBridge Report. (Exelon Objections at 3-4)

Exelon states that the IPA held a single stakeholder meeting on the subject of full requirements, and solicited written responses from stakeholders to a series of questions. Exelon notes the IPA has again chosen not to include full requirement products in its procurement approach. Exelon suggests that the analysis of full requirements was not as fulsome as was directed by the Commission. Exelon says the 2015 Plan refers back to, and relies heavily on, the analysis from the 2014 plan, but does not seek to address the shortcomings of that analysis identified by both ICEA and Staff. Additionally, while it includes some new analysis regarding potential premiums based on its review of certain New Jersey full requirements auctions, Exelon says the 2015 Plan makes no attempt to identify or quantify the benefits of full requirements. Exelon asserts it again looks only at one side of the coin. Exelon claims the Plan fails to properly recognize the additional costs, risks, and flaws inherent in its own proposed procurement approach in order to provide a true comparison of the different methodologies. (Exelon Objections at 4-5)

In order to procure supply required to meet the needs of "eligible retail customers", as defined within the PUA, Exelon recommends the Plan be modified to use FPFR 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 by including a pilot program for full requirements contracts for approximately 25% of the forecasted retail load. (Exelon Objections at 5)

Exelon argues that a diverse pool of wholesale full requirements product suppliers provides the most cost-effective method of management for eligible retail customers. Exelon says under full requirements product procurements, utilities provide to potential bidders prior to procurements, and to winning bidders on an ongoing basis afterwards, all of the load data for their individual customer classes. Exelon claims 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 contends such suppliers are able to draw from their substantial experience throughout PJM, MISO and other jurisdictions to develop proprietary models of customer behavior and switching patterns, to refine these models, and to better analyze the local data provided by utilities. Exelon says 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 asserts that wholesale suppliers have already invested in, and continue to make

significant investment in acquiring, experts in each specific type of market which makes up full requirements supply. (Exelon Objections at 5-6)

According to Exelon, 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 further asserts that 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)

In Exelon's view, a full requirements approach will best meet the requirements of Illinois law. Although the Plan looks only at what it deems to be the incremental cost difference between a block and spot approach and a full requirements approach, Exelon says it is important to keep in mind that "costs" to customers may include not only the prices paid by customers for IPA-procured supply, but the risks and lost opportunities they may face under a particular IPA plan. Exelon contends a full requirements approach will limit risks to customers by shifting them 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 states that as risks and costs to ComEd and Ameren appropriately are passed on to their customers, it follows that the full requirements approach limits the risk to utilities' customers by shifting them largely to full requirements product suppliers. (Exelon Objections at 6-7)

According to Exelon there does not seem to be a valid argument militating against full requirements from the perspective of the knowledge and expertise of potential bidders; rather, the only real debate appears to be one of cost versus risk. Exelon says the Plan appears to focus only on costs and, in Exelon's view, misunderstands what is referred to in the NorthBridge Report as "residual compensation," thereby misstating the difference in costs under a block and spot approach to one incorporating full requirements. As explained in the NorthBridge Report, residual compensation under full requirements is the amount of a bid remaining after pricing up the actual costs of the various components, i.e., energy, capacity, ancillary services. Exelon states that the Plan indicates that the difference in the expected rate under the block and spot approach versus full requirements is the entire residual compensation amount. Exelon insists that is simply not the case. While it is true that one would expect that winning bids under the block and spot approach would be lower than under full requirements, Exelon claims it would not be by a difference of the full residual compensation amount. Exelon argues that the block and spot approach itself is not merely the price build-up of the various components but, rather includes some level of supplier margin for performing the contracted products and services.

Exelon contends that element does not appear to have been factored into the analysis contained in the Plan. Exelon asserts that the NorthBridge Report contains the only uncontested analysis that actually provides an estimate of the difference in the expected rate under the full requirements approach versus under the block and spot approach. (Exelon Objections at 7-8)

While the Plan claims that the costs and benefits of full requirements cannot be quantified, Exelon believes that is not the case. Exelon says the NorthBridge Report, with which no party advanced any substantive disagreement as to its methodology or findings in the 2014 IPA Plan case, provided a thorough analysis demonstrating that full requirements pricing is reasonable given the costs and risks borne by those suppliers. According to Exelon, that evidence showed a difference of only 0.2% between full requirements and the block and spot approach, as shown on Table 6-1 of the Plan. Exelon says the second value on that table is the IPA's analysis from the 2014 procurement proceeding, which is based on a simulation analysis that has been shown to include significant shortcomings that invalidate its conclusions. Exelon asserts that the other two values in the table are based on residual compensation types of calculations which, as explained above, do not represent the difference in the expected supply rate level between a full requirements approach and a block and spot approach. (Exelon Objections at 8)

Exelon finds it significant that full requirements includes the value of the supplier bearing any risk associated with load – switching risk, weather-related risks, or any other difference between the forecasted load and actual load. In contrast, Exelon says the block and spot approach contains inherent risk that is not factored into the supplier bid, which is borne by customers, and which continues to be understated in the Plan, suffering from the same shortcomings as were explained in detail in the NorthBridge Report. Exelon also believes that under the Plan's notion that one should not purchase a full requirements product because there is some subjective judgment involved as to whether it makes sense to protect oneself against significantly bad outcomes, the entire insurance industry would not exist. (Exelon Objections at 8-9)

Although the Plan indicates that introduction of full requirements would require significant effort, Exelon contends initial set-up is not reason itself to reject the introduction of full requirements. Exelon claims that if that were a valid criterion for rejecting a proposal, there would never be any change from one Plan to the next. In Exelon's view, the goal is and should be to make advancements in procurement plans year over year, not to merely maintain the status quo when superior alternatives may exist. Exelon also says any effort would likely only be start-up costs for the first year. Exelon claims that given the number of states that currently use full requirements, there should be no shortage of resources to enable a smooth addition of full requirements to the competitive procurements contemplated under the Plan. Exelon states that many, if not most, of those same states do not have a centralized procurement agency and yet have not found full requirements to be unduly burdensome to implement. (Exelon Objections at 9-10)

Exelon supports a limited FPFR Pilot program that would involve the IPA conducting procurements side-by-side with its current block and spot procurements to provide the Commission, the IPA, and other stakeholders with actual market data in order to make a non-speculative, fact-based determination about the costs and benefits of FPFR. Exelon is recommending that the pilot program be limited to the ComEd service territory. (Exelon Response at 1-2)

In Exelon's view, nothing in the objections of other parties detracts from the benefits of FPFR procurements, generally, or the opportunity that a pilot program affords to the Commission and stakeholders to obtain real empirical data to determine the benefits of a FPFR procurement. Exelon says CUB claims that a decision to include a full requirements component should turn on whether or not customers perceive an added value. Exelon states CUB did not conduct a study or otherwise provide data to support this conclusion. Exelon says CUB provided no information regarding Illinois' customers' knowledge of how full requirements compares with a block-and-spot-plus-PEA approach, much less their perception of risks and benefits. Exelon asserts there is no indication that customers who remain on utility bundled rates have done so based on a conscious, informed decision based on favoring a block-and-spot-plus-PEA approach over a FPFR supply method (that may be offered by alternative retail electric suppliers). (Exelon Response at 2)

According to Exelon, to say that the benefits of price stability of FPFR are unknowable, as CUB indicates, is not a reason for the Commission to avoid the question altogether and never seek to explore the most widely used competitive procurement methodology used by electric utilities and public service commissions' in restructured, competitive markets across the U.S. Exelon says CUB falsely indicates that a pilot program would not provide any price stability for Illinois consumers, nor would it inform the IPA regarding the willingness of customers to pay for price stability. Exelon contends FPFR procurements do provide price stability for customers. Exelon claims that at the very least, the data coming out of the pilot will provide information to all stakeholders in order to evaluate the benefits of FPFR as a procurement strategy, including any price stabilizing benefits. Exelon suggests that to the extent the pilot reveals what Exelon, ICEA, and RESA believe to be true and FPFR procurement is incorporated more fully into future IPA plans, those benefits of price stability only increase. Exelon believes the fact that the benefits of price stability associated with FPFR procurements have not been fully explored in Illinois is not a reason to avoid the pilot program; rather, it is the reason that the Commission should adopt the pilot program in ComEd's service territory. (Exelon Response at 2-3)

4. CUB/EDF's Position

CUB supports the IPA's decision not to include full requirements contracts in the Plan. CUB asserts the choice to buy full requirements contracts should depend on whether or not the price is justified by the added value customers would perceive they obtain by eliminating the uncertainty around price. CUB claims there is no evidence that customers would see an added value, or would see an added value which exceeds the

price increase evidenced by the IPA's research. Though some parties have urged the IPA to incorporate a four-year pilot study of full requirements contracts, consisting of a 25% tranche of the IPA's total procurement in each of the four years, CUB agrees with the IPA that such an approach should be rejected. CUB says such a study is inappropriate in that it would not, in its own right, provide price stability for Illinois consumers, nor would doing a pilot inform the IPA as to the willingness of consumers to pay for price stability. (CUB Objections at 1-2)

CUB agrees that any benefits of price stability associated with full requirements are, at this time, unknowable. CUB says the studies provided by the IPA in the Plan, which detail New Jersey and Pennsylvania's experiences with full requirements contracts and two separate simulated models of such contracts in Illinois (one from the IPA and one from the NorthBridge Group) offer a variety of estimates for the cost of price stability. CUB states lacking is any evidence that eligible retail customers in Illinois would be willing to pay a risk premium for price stability. CUB suggests since individual consumers and municipalities have the option to choose price stability by selecting an alternative retail electric supplier, one could argue that remaining eligible retail customers are less likely to prefer a risk premium. CUB says implementing the proposed full requirements study would be at odds with the IPA's mandate under the IPA Act to "[d]evelop 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," as it would add administrative costs, and potentially raise the cost of supplied electricity (through inclusion of a risk premium), without providing a quantifiable benefit to consumers. (CUB Objections at 2-3)

CUB and EDF do not agree with ICEA and RESA that the IPA has fallen short in its analysis of full requirements products. CUB/EDF say in addition to its own Monte Carlo simulation, which predicted insurance premiums ranging from 2.8-3%, the IPA looked at real-world, *ex-post* data from New Jersey's experience with full requirements contracts, which found insurance premiums ranging as high as 12%. CUB/EDF claim this analysis is not, as RESA suggests, "based on speculation, not real results." CUB/EDF say the IPA relies on observed data, from a state in the same regional transmission organization as the ComEd service territory, PJM. CUB/EDF say ICEA, RESA, and Exelon continue to argue that only a parallel comparison of block and spot and full requirements approaches is the only way to determine their relative costs and benefits, without showing why the IPA should not expect to see the same results as New Jersey. (CUB/EDF Reply at 2-3)

CUB and EDF agree with the IPA in rejecting the rationale that full requirements contracts would be beneficial by providing a "price for comparison" for alternative electric suppliers. CUB/EDF believe the Commission should reject the concept of full requirements products, as appropriate analysis has already shown it would add predictable and significant cost to the IPA's energy procurement while generating little tangible benefit. (CUB/EDF Reply at 3)

CUB/EDF urges the Commission to also reject ICEA's proposal for a pilot program. CUB/EDF agree with the IPA that what ICEA is proposing is not a "pilot" but instead a change in procurement which would fail to generate the information necessary to allow the Commission to compare the results of a full requirements procurement with the IPA's existing "block and spot" approach. Staff appears to believe that this experiment could be designed to provide a side-by-side comparison. CUB/EDF also agree with the IPA that there is no experimental methodology that is suggested to compare the effects of the two procurement approaches given that all customers will still be subject to a purchased energy adjustment. CUB/EDF believe there will still be no answer to the question of whether or not a pilot will provide any information on the benefits of a full requirements procurement or on the willingness of customers to pay for price stability. (CUB/EDF Reply at 3)

5. The IPA's Position

The IPA does wish to acknowledge the efforts of ICEA in moving the conversation forward from the 2014 Plan through carefully explained reasoning and distillation of contested issues to key points. However, the IPA disagrees with the objections of ICEA, RESA, and Exelon and recommends no changes to the IPA's proposed procurement strategy. (IPA Response at 3)

The IPA says its objective is to obtain electric service satisfying various criteria at the "lowest total cost over time," but balanced against customer benefits realized through more stable prices – to strike an appropriate balance between competing goals. The IPA states that at one end is complete reliance on the spot market for procurement, which would be expected to bring the lowest prices, but would offer the lowest price stability. The IPA claims its current "block and spot" procurement approach sits near the middle, balancing low costs with relatively more stable prices. (IPA Response at 3)

The IPA asserts the defining characteristic of fixed-price full requirements service is that the price is fixed. It offers total stability, representing the opposite end of the spectrum from reliance on spot market prices. The IPA believes this would be an appropriate policy if price stability were the paramount objective enumerated in the IPA Act, but it is not. In the IPA's view, balance between cost and stability is paramount. By trading maximum price impact for maximum stability, the IPA believes full requirements procurement fails to balance competing goals. The IPA suggests that perhaps this balance could be achieved if corresponding costs were negligible. (IPA Response at 3-4)

The IPA claims *ex post* analysis from New Jersey, in its view the best and most reliable evidence introduced to date, demonstrates that full requirements procurement carries significant expected price premiums for eligible retail customers. The IPA notes that ICEA, RESA, and Exelon continue to rely exclusively on modeled data from last year's NorthBridge Report, and the IPA's new analyses are largely uncontested. (IPA Response at 4)

The IPA believes an analysis of full requirements costs should also be compared with its expected benefits. According to the IPA, no sharper understanding of alleged benefits is evident from any party's objections. While the IPA attempted to distill out any such benefits for its 2015 Plan by examining analyses of customer risk preference, it claims no clear picture emerged. (IPA Response at 4)

The IPA states that against a backdrop of established evidence demonstrating meaningful costs and mere speculation about potential benefits, the IPA strongly believes that full requirements procurement does not strike an appropriate balance between achieving the "lowest cost" while capturing benefits of "price stability" consistent with the IPA Act. The IPA says it is confident of how well its current procurement approach is working, and views the full requirements proposal as a solution in search of a problem. (IPA Response at 5)

According to the IPA, the imbalance introduced by full requirements is not remedied by proposing full requirements procurement for a portion of the IPA's procurement labeled as a "pilot program." The IPA states that as "partial full requirements" would simply shift the IPA's achieved balance toward increased stability at added cost for reasons that have no compelling statutory or empirical justification, the IPA believes this proposal must be rejected. (IPA Response at 5)

In the IPA's view, this conclusion is also undisturbed by arguments that full requirements will help promote 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. The IPA believes such arguments must be rejected. The IPA is not directed to provide a benchmark for ARES' offerings by the IPA Act. While the IPA appreciates the goal of robust retail competition, the IPA says it is directed to develop procurement plans ensuring the lowest total cost over time, taking into account any benefits of price stability. The IPA believes modifications to the IPA's procurement approach so that ARES may have a slightly better target to compare cannot constitute concrete benefits to eligible retail customers sufficient to justify established costs. (IPA Response at 5)

The IPA insists its existing procurement approach best balances the competing goals of "lowest cost" and "price stability." The IPA also maintains full requirements procurement features the introduction of the unnecessary costs for speculative benefits. As the PUA directs the Commission to "approve the procurement plan . . . if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability", the IPA contends its existing procurement approach should be affirmed. (IPA Response at 6, citing 16-111.5(d)(4) of the PUA)

The IPA claims the phrase "pilot program" is a misnomer, arguing this proposal is simply a partial implementation of full requirements. The IPA says this is underscored by its size: The IPA indicates ICEA first uses illustrative examples related to a 20% procurement, but then goes on to recommend a 25% tranche of the total load go to

FPFR each of the four years. The IPA says its proposed procurement approach features the following annual hedges: prompt delivery year - 100%; second delivery year - 50%; third delivery year - 25%. The IPA states that when the second year becomes the prompt year, its supply needs should already be 50% hedged, leaving the prompt-year procurement need as 50% of the forecast load. (IPA Response at 6-7)

According to the IPA, 25% of total load tranche for full requirements would mean that half of the prompt-year procurement goal would be for full requirements. In the IPA's view, what ICEA describes as a "pilot program" is in fact chopping the IPA's procurement in half and adopting an unwarranted new procurement strategy for one side. As the IPA believes that requiring any level of switching to full requirements procurement has not been adequately justified, the IPA insists it is not justified for half of the IPA's procurement goal. (IPA Response at 7)

The IPA asserts ICEA's proposal purports to be a "pilot" project with the intent of providing additional information to the Commission to make future decisions, but lacks necessary information gathering framework. The IPA says ICEA seems to believe that at the end of four years, prices can simply be compared for a Commission decision. The IPA believes this is an oversimplification. (IPA Response at 7)

The IPA states that the proposed "pilot program," or partial procurement, will apparently just attempt to quantify the price differences between the two procurement approaches in a vacuum. The IPA believes gleaning useful information may be a chore. The IPA complains the proposed pilot program fails to specify the methodology for comparing the effect(s) of the two procurement approaches. The IPA says there is no "treatment group" of customers receiving pricing based on fixed-price full requirements contracts, and no "control group" receiving pricing based on the IPA's normal purchase strategy. The IPA indicates every customer will still be subject to the PEA. More importantly in the IPA's view, the proposed "pilot program" also studies the wrong policy question. The IPA asserts detailed information provided by the IPA and ICEA in both proceedings already extensively discusses the costs of full requirements. If anything needs to be studied further, the IPA believes it is the potential benefits of full requirements, yet the IPA says this is unaddressed by the proposed "pilot." The IPA recommends that adoption of full requirements for any portion of its procurement, as a "pilot" or otherwise, should be rejected. (IPA Response at 7-8)

While the IPA believes that any implementation of full requirements procurement is unwarranted, should the Commission disagree, the IPA has recommendations which it believes must govern any pilot program's adoption. The IPA operates under an annual appropriation from the General Assembly which may not be exceeded. For the fiscal year ending June 30, 2015 ("FY15"), the IPA's appropriation for its operations fund is $1.913 million. The IPA says it has examined its FY15 spending to date, as well as its projected spending for remaining FY15, and expects that spending to be between $1.2 and $1.6 million. The IPA says the projected cost of implementing an additional full requirements procurement is $850,000 for both utilities, and 25 to 30% lower for one utility. The IPA also says those costs are incurred prior to the procurement event and

must be allocated to the correct year's appropriation. Implementing full requirements procurement for ComEd alone would barely fit into the current year's appropriation, and only if other costs came in low. (IPA Response at 8-9)

Purely from the perspective of IPA finances, the IPA claims it would be problematic for the IPA to add full requirements procurement to the April 2015 procurement date. Should any full requirements procurement be approved by the Commission, the IPA urges the Commission to delay such a procurement until at least 2016. The IPA suggests this would allow the IPA and its procurement administrator time to properly plan for the procurement and for the IPA to increase its request for the appropriation for the fiscal year starting July 1, 2015 to a level sufficient to pay for the additional procurement administration expenses. (IPA Response at 9)

The IPA believes a successful pilot program would require a plan for how research and evaluation would be conducted. The IPA states that among the relevant questions:

- What data needs to be gathered?
- What data can and will be isolated?
- Who conducts the evaluation?
- Would an independent evaluator be hired?
- If so, who would pay their costs?

Should any pilot program be approved, the IPA believes these questions must be first answered. (IPA Response at 9)

The IPA states that for the ComEd AMI pilot approved in Docket No. 09-0263, the Commission adopted ComEd's recommended "hold harmless" provision. Under this approach, the IPA says customers participating in the rate pilot part of the broader AMI pilot did not experience rate impacts if the pilot program increased their bills. (IPA Response at 9-10)

If the Commission chooses to approve a full requirements pilot program, the IPA recommends that such a provision again be offered to provide similar customer protection against full requirements contracts increasing overall supply cost. In the IPA's view, this is especially important because such customers cannot simply "opt out" of potentially more expensive procurement and retain their right to take service from the utility; instead, they would have to actively seek an alternative option from an ARES. The IPA contends such costs should be borne by those who propose this pilot procurement and/or who may stand to benefit from its implementation. (IPA Response at 10)

While the IPA believes any partial implementation of full requirements is not justified, the pilot may be incomplete if it does not include default service customers of Ameren. The IPA suggests differences between the PJM and MISO markets may be

significant and if this type of pilot were to be conducted, it would be a lost opportunity not to include Ameren customers. (IPA Response at 10)

According to the IPA, ICEA's proposal appears to call for procuring full requirements contracts for half of the volume to be procured for the prompt year. The IPA claims ICEA provides no basis for why this is the appropriate volume for the pilot program. The IPA recommends that prior to any consideration of a pilot program, clear and explicit consideration be given to the size of the pilot. The IPA suggests the size should be sufficient to provide statistically meaningful results, but the IPA is not clear why it should be any larger than necessary to provide those results. (IPA Response at 10)

Throughout their comments, the IPA says ICEA, Exelon, and RESA all argue that the Commission's Final Order on the 2014 Plan directed the IPA to fix its analysis of full requirements because of "shortcomings" in that analysis. The IPA believes this is a selective reading of the Commission's 2014 Order. (IPA Response at 11)

In the Commission's review of the NorthBridge Report, the Commission stated that "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 IPA claims the Commission did not necessarily endorse those critiques; the IPA says it merely noted that such critiques were raised and that Staff shared some agreement. The IPA states the Commission further went on to explicitly state that the IPA amended its analysis in the filed plan to "address these issues," something the IPA complains is left unmentioned or deemphasized by the objectors. (IPA Response at 11)

The IPA believes it has faithfully met the requirement in the Final Order in Docket No. 13-0546. In the IPA's view, all discussion of the 2014 Plan could be removed from the 2015 Plan, and the remaining new analysis would be more than comprehensive enough to support the 2015 Plan's conclusions. (IPA Response at 11-12)

The IPA states the 2015 Plan includes a new analysis of price premia from New Jersey that specifically adopts an approach recommended by Staff in response to questions issued after the IPA's June 2014 workshop, to which no party has objected; additional full requirements premia analyses from ICEA's expert in a Pennsylvania proceeding; and an exploration of the potential "benefits of price stability" through an analysis of customer interest. Additionally, the IPA says it provided an estimate of the cost of developing a full requirements procurement as requested by the Commission. The IPA insists it has completely and faithfully complied with the Commission's directive. (IPA Response at 12)

The IPA notes that Commission also stated in the Final Order in Docket No. 13-0546 that it does not believe sufficient evidence has been provided in that proceeding to make the policy shift at this time. The IPA argues that no new evidence has been provided by objectors, who still insist on last year's NorthBridge report as the only

evidence necessary to substantiate their position. The IPA contends that against the backdrop of insufficient evidence in last year's proceeding, it is unclear how this same evidence could now be considered sufficient to justify adoption of full requirements procurement one year later, especially when compared to the significant new evidence provided by the IPA. (IPA Response at 12)

The IPA says ICEA continues to rely on last year's NorthBridge Report, which Exelon also says contains the only uncontested analysis. The IPA believes the relevance of the NorthBridge Report to the current proceeding is very limited. (IPA Response at 13)

According to the IPA, during the 2014 Procurement Plan proceeding, the IPA concluded that regardless of its overall opinion of NorthBridge's Monte Carlo analysis, NorthBridge arrived at the same general conclusion about the existence of a full requirements price premium as did its own analysis. Thus, the IPA saw no reason to provide a more thorough critique. For consideration of its 2015 Plan, the IPA believes the NorthBridge Report has become superseded by the IPA's new evidence, the analysis of New Jersey price premia and recent testimony from Pennsylvania by the author of the NorthBridge Report. The IPA complains that ICEA has chosen not to update last year's NorthBridge Report, and simply includes it again as Attachment A to its Objections. (IPA Response at 13)

As parties continue to allege that the NorthBridge report is "uncontested," the IPA offers several criticisms of the NorthBridge report it withheld from raising last year.

- First, the Northbridge report is a critique of the 2014 draft procurement plan the IPA released on August 15, 2014, and not the plan filed with the Commission on September 30, 2014. As recognized by the Commission, the filed plan addressed concerns raised by NorthBridge. While aspects of the 2014 plan remained unchanged, the failure of ICEA to update the NorthBridge Report renders it incomplete and inaccurate.

- Second, the NorthBridge Report contains an extensive discussion of the price distortions created by the PEA during the time period covered by swap contracts. The IPA believes this discussion thus fails to accurately critique any actual IPA proposed, or Commission approved hedging strategy. Such discussion may only be instructive to any consideration of broad-brush long-term commitments that do not allow for flexibility and adjustment, which does not reflect the IPA's current procurement approach.

- Third, NorthBridge's analysis of the 2012 PECO procurement was a Monte Carlo simulation, not the reporting of real world results. To quote Northbridge, "[t]he PECO analysis involves the application of different default service approaches to 1,000 different but equally likely market scenarios [72] that reflect complex real-world market dynamics, consistent with the volatilities, correlations, and mean reversion of market price and load changes observed historically."(NorthBridge

Report at 34) This footnote further explains that "[i]n this context, a `scenario' is a potential state-of-the-world that may unfold. Each scenario includes a trajectory for how forward prices for energy may vary over time, what spot prices might result, how customer load may vary, and what the cost to serve customers will be." As such, the PECO analysis is not nearly as definitive as has been implied in Objections. Without more specifics on the scenarios considered, including frequency distributions (as the IPA provided in its 2014 Procurement Plan in Figures 6-2, 6-3, and in a slightly different format 6-11 and 6-13), these results are merely one model of possible outcomes.

- Fourth, the NorthBridge Report overstates the risks of the various adverse scenarios. The three risk metrics -- Default Service Rate Shock, Supply Cost Surprise and Deferred Cost Recovery Balance – are characterized as "top decile" values. (NorthBridge Report at 36). This may imply that they are 90th-percentile values, with a one-in-ten chance of occurring. In fact, however, they are averages over the top 10% of simulated outcome, which makes them more like 96th percentile values. Such outcomes have only a one-in-25 chance of occurrence.
  (IPA Response at 13-14)

The IPA says it now has serious questions about the NorthBridge Report's reliance on the ComEd PEA as an indicator of price instability. Since the 2014 proceeding, the IPA says ICEA has clarified that its preferred form of a full requirements product would not include capacity. The IPA states that ComEd retail rates are charged on energy usage, but capacity costs are based on peak load responsibility. The IPA says the $/MW capacity charge is converted to a ¢/kWh energy charge based on an assumed load factor. The IPA asserts variations in actual load factor can lead to over or undercollections which must be recovered through the PEA. In the IPA's view, it is likely that load factor and capacity effects can be a significant factor in the monthly volatility of the PEA, although data has not been available to IPA to assess the magnitude of this effect. The IPA says if capacity is a significant contributor to PEA, then a full requirements product that excludes capacity will not avoid that contribution to the PEA's monthly volatility. (IPA Response at 15)

The IPA states that its new analyses of New Jersey procurements from 2009 through 2014 contain direct observation of actual procurement results and actual market prices. Unlike the NorthBridge Report examination of the 2012 PECO procurement (and the IPA's 2014 Plan analysis), the IPA reports it is not a Monte Carlo simulation. Using the standard suggested by Staff and endorsed by ICEA, the IPA claims it is the best available evidence. Most notably, that analysis is not the subject of any objections. The IPA believes that these results provide the Commission ample guidance. (IPA Response at 15)

In its 2014 Plan, the IPA says it tweaked its procurement strategy to better manage risk by adjusting hedging levels and a balancing procurement event in September. In this year's Plan, the IPA proposes incremental refinements to balance

the spring and fall procurements, providing risk management improvements by allowing the IPA more flexibility in matching procurement volumes with forecast customer demand. (IPA Response at 15-16)

In the IPA's view, these constitute incremental changes to further improve a system that is working, not a fundamental shift as with the approach that ICEA, RESA and Exelon advocate. The IPA believes these changes responsibly address the issue of customer switching risk in ways that are not disruptive to the proven IPA procurement approach, an approach that is benefiting customers through cost savings. (IPA Response at 16)

The IPA insists the exposure to risk in the IPA's proposed procurement strategy is in line with the expected cost outcomes. The IPA believes what ICEA, RESA, and Exelon propose is a fundamental change in procurement approach that would further reduce that exposure to risk, but at an unknown but expected cost. In the IPA's view, and consistent with its statutory guidance, a change in strategy to an approach that would reduce the already small risk exposure to an even lower level is not justified by the expected but unknown additional cost. (IPA Response at 16)

According to the IPA, the objectors suggest that the IPA's proposed procurement approach fails to adequately address switching risk. The IPA maintains approximately 10% of ARES customers have recently returned to utility service. The IPA says procurement volumes for the September 2014 procurements for ComEd and Ameren were adjusted to account for additional load. The IPA contends that this approach further demonstrates how the IPA is effectively managing switching risk. The IPA claims further refinements proposed in the 2015 Plan will not only continue that flexibility, but by shifting additional procurement volume to Fall 2015, they will allow for the management of lower than expected returns to utility service or the increase of customers to ARES. (IPA Response at 16-17)

In its Reply to Responses, the IPA states nothing offered in the Responses of ICEA, Exelon, or RESA changes the IPA's position opposing the implementation of partial full requirements procurement. The IPA claims rather than introducing critiques of the IPA's new analyses contained in the 2015 Plan or justifying full requirements procurement on evidence other than last year's NorthBridge Report, parties advocating for full requirements simply repeat each other's mutually-supported positions. (IPA Reply at 1-2)

The IPA generally agrees with the AG's comments offered in Response, particularly that the timing for a significant change to the IPA's procurement approach – whether due to recent changes in the PEA, or pending federal carbon pollution rules – is not ideal. The IPA states that while its proposed procurement strategy is based on statutory guidance and a proven risk management approach, the Commission may wish to consider how procurement modifications could create new challenges in meeting other priorities, or how data resulting from a "pilot" may be spoiled or rendered moot. In the face of impending changes and uncertainty as articulated by the AG, the IPA

believes now is a poor time to conduct an experiment in which the IPA would be locked into to a mandated procurement approach. (IPA Reply at 2)

The IPA asserts that for it, this raises a broader concern about the propriety of mandating any four-year procurement approach in a given year's procurement plan proceeding. Currently, the IPA has the flexibility to produce a plan each year that is tailored to the specific circumstances affecting the electricity markets at that time. The IPA contends that requiring that a specific approach be adopted for four years would tie its hands in this respect. The IPA claims an inability for it to adjust its risk management approach based on market conditions is troubling, and endangers the IPA's future ability to meet "the lowest total cost over time, taking into account any benefits of price stability" in developing procurement plans. (IPA Reply at 2)

The IPA also appreciates the AG's recognition of its considerate, principled approach to procurement reflected in its "deep consideration of portfolio management." The IPA agrees that unlike suppliers, the IPA does not operate with a profit motive. It seeks the procurement approach which best meets the standards outlined in the IPA Act and that is most appropriate for the current and expected market conditions. (IPA Reply at 3)

The IPA finds compelling the AG's argument that having the IPA procurement strategy reflect a distinct methodology serves to benefit customers through a "vibrant competitive market." The IPA maintains that unlike in other restructured states, bundled service in Illinois is not merely a "provider-of-last-resort" option. The IPA says it has an established, important role within a competitive market by procuring wholesale supply for a distinct product that customers may actively elect should it provide a more attractive option. The IPA emphasizes that it does not produce procurement plans to support ARES' competitive market needs; it produces procurement plans to procure standard wholesale products to maximize benefits and minimize costs for customers who choose bundled service. The IPA insists the ability to implement a procurement strategy that addresses price stability through the use of a three-year forward-looking laddered hedging approach using standard products is a unique role the IPA can play in the market, and a role expressly granted to the IPA by the General Assembly. (IPA Reply at 3)

The IPA claims ICEA flips this argument, claiming that should full requirements be adopted, customers seeking less stability could acquire a variable-rate ARES product or utility real-time pricing options. The IPA argues that in understanding why such impassioned arguments for full requirements procurement are offered, an argument from an ARES trade association that displaced customers can leave bundled service and acquire a variable-rate ARES product may be instructive. The IPA agrees with the AG that narrowing the procurement strategies to the one preferred by the suppliers represented by ICEA, RESA, and Exelon is not in consumers' interest and would represent a lost opportunity to make the competitive market work for consumers. (IPA Reply at 3-4)

The IPA says full requirements advocates continue to rely heavily on the Commission's Order in Docket No. 13-0546 and its treatment of ICEA's September 2013 NorthBridge Report. The IPA maintains that while the Commission found an analysis within the NorthBridge Report "compelling" in last year's proceeding, it did so a) without the benefit of robust critiques or competing analyses, unlike in the present docket, and b) while also determining that the NorthBridge Report alone was insufficient grounds for modifying the IPA's procurement approach. (IPA Reply at 4)

The IPA states that in the present docket, only the September 2013 NorthBridge Report supports RESA, ICEA, and Exelon's position; no new evidence supporting full requirements procurement has been introduced. The IPA contends that faced with robust evidence demonstrating more significant expected cost premiums and a limited basis for critiquing that evidence, these parties are left with a single path forward: building up the perceived importance of the NorthBridge Report. (IPA Reply at 4)

According to the IPA, the Commission should base its decision on the full record in the present docket, and assess the expected costs and potential benefits of full requirements procurement with the benefit of the multiple analyses provided by the IPA. In the IPA's view, the NorthBridge Report must be understood as merely a single reference point, one that relies on a computer simulation of market results, and which has been thoroughly critiqued by the IPA in Response, and any arguments that the Commission should be compelled by the September 2013 NorthBridge Report simply because of its role in a prior proceeding must be rejected. (IPA Reply at 4-5)

The IPA says RESA, Exelon, and ICEA continue to claim that the IPA's analysis in its Plan was "insufficient" and features "shortcomings." The IPA asserts the 2015 Plan is more comprehensive in analysis type. Unlike Docket No. 13-0546, where parties only had the benefit of a lone computer simulation, the IPA says the 2015 Plan looks at both modeled data and actual *ex post* price information, which both Staff and ICEA agree constitutes the best possible evidence. The IPA says the Plan also incorporates survey data in an attempt to identify customer benefits through customer preferences. The IPA notes no party has alleged that analysis of a different type should have been used by the IPA. (IPA Reply at 5)

The IPA claims the 2015 Plan is more substantial in volume. The IPA recognizes that no single reference point is sufficient to make an informed decision, just as the Commission recognized last year that the NorthBridge Report alone was insufficient to justify a departure in the IPA's procurement approach. The 2015 Plan features an examination of full requirements procurement in New Jersey, testimony from a proceeding in Pennsylvania, and references back to prior modeled analyses specific to Illinois. The IPA says no party has suggested that the IPA look to different jurisdictions than those examined in its Plan, that the jurisdictions subject to examination are too flawed for valid comparison, or that the IPA needed a fifth or sixth reference point to meet the Commission's Docket No. 13-0546 directive. (IPA Reply at 5)

While the positions of ICEA, RESA, and Exelon are clear, the IPA claims less clear is what these parties believe is actually missing from the IPA's analysis. The IPA believes it has demonstrated that its analysis is sufficiently thorough and comprehensive, and that this is a classic example of parties not liking the results and consequently criticizing the process. (IPA Reply at 6)

Along similar lines, the IPA notes ICEA states in Response that a Commission decision need not be made by choosing between "competing speculative models." The IPA strongly disagrees that "competing speculative models" is a fair characterization of the record. Unlike the September 2013 NorthBridge Report, which is based on a computer model, the IPA insists *ex post* data from New Jersey is not speculative and is derived from an empirical analysis of cost actual premiums paid by actual eligible retail customers. (IPA Reply at 6)

The IPA also disagrees that the balance of evidence is merely "competing." Instead, the IPA insists the balance of evidence weighs heavily in favor of a conclusion that does not support ICEA, RESA, and Exelon's position; specifically, that expected cost premiums from full requirements procurement are far more significant than those found in the September 2013 NorthBridge Report. In the IPA's view, the proposed "pilot" is merely an attempt to create yet another data point to estimate premiums, but using supply rates paid by actual Illinois customers to do so. (IPA Reply at 6)

The IPA says Exelon, RESA, and ICEA all offer some variation of an argument that because CUB has failed to introduce any "study" indicating that customers do not value price stability, CUB's arguments that these benefits are unknown or merely speculative should be rejected. The IPA disagrees. (IPA Reply at 6)

The IPA says RESA and ICEA are seeking a significant departure from the IPA's existing procurement strategy, claiming benefits can be achieved sufficient to justify an expected price premium. The IPA argues that unable to themselves substantiate such benefits, these parties seek to flip this standard, stating "there is not sufficient evidence that bundled service customers would not value" additional "insurance and stability," as though the IPA and CUB carry the burden of justifying the absence of alleged benefits. The IPA claims this is incorrect. In the IPA's view, RESA, ICEA, and Exelon must justify the presence of such benefits, especially against a record demonstrating expected cost. (IPA Reply at 7)

The IPA claims RESA even appears to agree with CUB that "benefits are unknowable," claiming that this fact justifies a departure from the IPA's existing procurement strategy to explore possible benefits through a "pilot." In the IPA's view, this is an improper rationale for the adoption of a "pilot" proposal. (IPA Reply at 7)

The IPA maintains the proposed "pilot" features no framework to define and measure benefits, let alone determine whether any such benefits are sufficient to justify costs. The IPA asserts no party has identified any variable to be analyzed through this "pilot" in determining whether benefits have been realized, how such a variable would

be measured, who would be responsible for its measurement, and how the costs for any such benefit evaluation would be allocated. (IPA Reply at 7)

The IPA believes it is important that the governing law cannot support the adoption of a more costly procurement strategy to search for benefits and help build arguments that RESA, ICEA, and Exelon cannot substantiate in this docket. The IPA claims it is incumbent on advocates for full requirements to demonstrate that their proposed approach would achieve the "lowest cost over time, taking into account any benefits of price stability" prior to a modification in the IPA's procurement approach. The IPA asserts failure to make this demonstration cannot be construed as grounds to adopt modifications in an effort to explore whether those arguments may have been correct. (IPA Reply at 7-8)

The IPA believes RESA's rationale that without a "pilot," the IPA is rejecting "out-of-hand, a potential superior alternative" must be rejected. The IPA says taken to its logical conclusion, this reasoning could justify experimentation via any procurement approach that has not yet been adopted. The IPA asserts this is inconsistent with the Commission's responsibility to determine whether the IPA's Procurement Plan accomplishes statutory objectives based on the record evidence and governing law. (IPA Reply at 8)

The IPA says ICEA, RESA, and Exelon seem to imply that because "only" CUB submitted objections supporting the IPA's position, the weighted balance of objectors provides support for adoption of their proposal. In the IPA's view, the number of parties supporting a position is inconsequential. It is not clear to the IPA why any party must "object" to something to which it offers agreement. The IPA says the AG chose not to "object" in analyzing full requirements procurement, and instead offered its perspective in Response. The IPA states nothing prohibits this approach and the plain meaning of the term "objection" may encourage it. (IPA Reply at 8)

The IPA notes that only parties with a profit motive are supportive of full requirements. The IPA suggests these parties stand to benefit financially from a problematic bundled supply rate (more expensive, too volatile), as dissatisfied customers would be driven to ARES service. The IPA claims recent experience in Illinois has demonstrated that customers will leave ARES and return to the IPA-procured utility supply rate when it constitutes a more attractive option. (IPA Reply at 8-9)

The IPA claims this "switching back" has occurred despite a statutory prohibition against utility marketing of supply rates, unlike the aggressive marketing seen from ARES. In the IPA's view, this demonstrates that such decisions are being made by informed consumers (or their agents, in the form of municipal officials in aggregated communities) cognizant of potential benefits, such as lower costs, derived from the IPA's existing procurement approach. (IPA Reply at 9)

The IPA agrees with the AG and CUB that ICEA's partial full requirements "pilot" proposal should not be adopted. However, if the Commission disagrees and finds that implementing a partial full requirements "pilot" is justified, the IPA recommends that it consider the concerns raised by the IPA in its Response about "pilot" design, implementation, and evaluation. The IPA says as advocates for this proposal have stated that its primary purpose would be for the development of new information, the IPA stresses that the Commission should adopt the principle that retail customers who would otherwise pay the incremental cost of full requirements procurement be held harmless under the approval of any "pilot" program. (IPA Reply at 9-10)

In its Brief on Exceptions, the IPA complained about the resources expended on FPFR issues. The IPA seeks direction from the Commission that it does not seek consideration of the same (or substantially similar) arguments in future dockets. The IPA asserts that absent compelling new arguments supported by quantified data on benefits to eligible retail customers, this issue should be considered closed and the Commission should not expect the IPA to provide further analysis beyond what the IPA chooses to conduct. (IPA BOE at 2-3)

The IPA states that the purpose of this proceeding is to analyze and approve the annual Procurement Plan developed by the IPA. Through this process, the IPA says the Commission considers the merits of objections presented by parties seeking to modify the Agency's Plan. The IPA believes the Commission properly framed this exercise when rejecting an earlier full requirements proposal by Constellation, stating that it has not demonstrated that its proposal is superior to the IPA's, from the perspective eligible retail customers. The IPA claims this remains the correct framework: the IPA's Plan should only be modified due to the introduction of a "superior" alternative for eligible retail customers, and the burden of demonstrating the superiority of alternatives lies with parties making such proposals. (IPA RBOE at 2)

The IPA believes that ICEA and RESA's exceptions seeking adoption of fixed price full requirements procurement based on the September 2013 NorthBridge report must be rejected. The IPA says ICEA and RESA now rationalize their proposal as an attempt to find benefits. The IPA claims this is inappropriate, unsubstantiated, and wholly unauthorized under the law. The IPA says its procurement approach must be expected to produce the lowest costs over time, taking into account any benefits of price stability and that same standard governs the Commission's review. The IPA argues that because ICEA and RESA seek to modify the IPA's procurement approach so as to increase expected costs, it is incumbent on these parties to demonstrate commensurate expected benefits through the evidentiary record in this proceeding, where this change would be approved. The IPA contends not only have full requirements proponents failed to do so, they have arguably made no attempt. (IPA RBOE at 3-6)

6. Staff's Position

Staff neither supports nor opposes ICEA's proposal. In Staff's view, the issues surrounding FPFR contracting have been thoroughly discussed and are ready to be

addressed by the Commission. However, Staff disagrees with one of CUB's arguments. While CUB is correct that a 25% pilot program "would not, in its own right, provide price stability for Illinois consumers," Staff says this CUB criticism overlooks the benefits of such a pilot. Staff believes the value of such a pilot would be to provide side-by-side comparisons between the bidding results of a fixed-price fixed-quantity (block) procurement and a FPFR procurement, conducted nearly simultaneously and for the same delivery periods. Staff claims such experiments would provide additional relevant data on the relative cost of the two procurement approaches. (Staff Response at 3)

7. The AG's Position

The AG notes that ICEA, RESA, and Exelon all object to the IPA 2015 Procurement Plan because it does not adopt ICEA's proposal to purchase 25% of the ComEd supply through a four year pilot program using "fixed price full requirements" contracts. According to the AG, these parties all represent suppliers who currently operate in the Illinois electric supply market, as suppliers to individuals, businesses or municipalities. While not stated, many of these parties primarily offer FPFR contracts to their customers. (AG Response at 2-3)

The AG states that one argument made last year for moving to FPFR procurement was that the suppliers did not have an accurate "Price-to-Compare" due to monthly adjustments the utilities make to their supply charges in their "purchased energy adjustment" riders. The AG says the Commission, the IPA and the utilities have considered improvements to the PEA, which appear to be moderating the influence of the PEA, if not reversing its effect. According to the AG, while in past years ComEd customers have mostly seen PEA charges, over the last six months the PEA charges have been credits, reducing customer bills. Given this change in the operation of the PEA, the AG believes the Commission should give suppliers and consumers time to accommodate to and assess this new PEA methodology and its effect on the "price to compare" discussed last year. The AG says ICEA, RESA and Exelon did not rely on issues related to the PEA in their objections or cite the operation of the PEA as a reason to adopt FPFR procurement. (AG Response at 3)

The AG suggests that in considering the arguments that a FPFR pilot procurement should be adopted for the next four years, the Commission should bear in mind that there are major changes being discussed in Illinois and nationally that can have major but as yet undetermined, effects on the electric supply market. The AG states that last June the United States Environmental Protection Agency ("U.S. EPA") issued rules to cut carbon emissions at power plants nationwide. The AG says Illinois is expected to reduce its carbon emissions by 1,895 to 2,189 pounds of carbon dioxide, according to the Illinois EPA. The AG expresses concern that conducting a pilot program when so much is in flux may confuse the data as it will be difficult to identify causes and effects of price and market changes. (AG Response at 3-4)

According to the AG, the U.S. EPA rules will not be final until next June, barring no additional delay. The AG suggests the new rules combined with how the Illinois

General Assembly decides to address the state and market issues raised by the rules may affect the costs of coal, nuclear, natural gas, and renewable supply in the coming years. Until then, the AG claims Illinois cannot fully anticipate its obligations or the effect of the federal rules on Illinois electricity markets. The AG alleges significant uncertainty stems from the extent that Illinois adopts carbon specific or other energy policies in the coming two years. (AG Response at 4)

The AG says the suppliers who advocate for a 20% pilot program assert that a pilot is necessary so the Commission can compare FPFR procurement with block procurement. The AG argues that in the Illinois competitive market, suppliers have had ample opportunity to provide FPFR contracts to consumers as well as municipalities. The AG says that choice is the essence of a competitive market. In the AG's view, if all supply is procured the same way (or influenced by a FPFR procurement block), the market will lose one key procurement approach. (AG Response at 4-5)

In the AG's view, the IPA's current block approach provides an independent means to determine the cost of risk. The AG claims full requirements contracts include the cost of demand volatility in the price. While the risk premium may be determined through various measures, the AG believes ultimately the risk premium is not obvious or transparent. The AG argues that by contrast, while the block approach used by the IPA does not include a risk premium, the PEA effectively shows the cost of volatility of demand by reconciling cost and revenues. The AG suggests this allows an assessment of the cost of demand risk and is a more transparent method to assess the cost of risk. (AG Response at 5)

The AG contends that consumers have the option to select supply at fixed rates from suppliers today. Regardless of analyses or surveys about consumer tolerance for price volatility, the AG believes it is prudent for the IPA to continue to use a procurement method other than the one used by most suppliers to preserve procurement options available to consumers. The AG claims prices obtained through the IPA's approach have been very consistent with market prices and with a reasonable cost for volatility as expressed in the PEA. The AG insists that moving to a different procurement method to match the one preferred by suppliers will limit the range of market options available to consumers. (AG Response at 5)

Exelon argues that suppliers are better positioned to manage risk because their business depends on it. The AG states the job of any procurement agent is to manage its portfolio. In fact, the IPA 2015 Procurement Plan reflects deep consideration of portfolio management. The AG argues the notion that the IPA procurement strategy is stagnant or rigid should be rejected as not based in fact. The AG says the IPA procurement plan reflects an approach to risk management that is an alternative to FPFR procurement. The AG states that the quality of that portfolio management should be reflected in the IPA prices and competitive suppliers' portfolio management is reflected in their prices. The AG maintains that replacing the IPA management solely with supplier management will eliminate the opportunity for IPA, not-for-profit management of supply. (AG Response at 5-6)

The AG believes the Commission should resist the argument that there is only one "best" way to obtain electric supply. Exelon argues that the IPA did not "attempt to identify or quantify the benefits of full requirements." The AG states that while the IPA did attempt to tease out the "premium for price insurance" or risk premium in various FPFR procurement, IPA 2015 Procurement Plan at 59-63, it correctly concluded that the difficult question is when risk premium is reasonable and when is it too much? The AG says the role of the IPA is to utilize the electricity supply market to obtain the best price over time, taking into account any benefits of price stability. While the suppliers assert that more stability is necessary and can be achieved by moving to full requirements procurement, the AG believes it is less than clear that FPFR procurement will also obtain the best price over time or preserve alternative purchasing strategies. In the AG's view, to date, the competing procurement strategies of the IPA and the other suppliers have resulted in a vibrant competitive market and extensive municipal aggregation. The AG maintains that narrowing the procurement strategies to the one preferred by the suppliers represented by ICEA and RESA (and Exelon) is not in consumers' interest and would represent a lost opportunity to make the competitive market work for consumers. (AG Response at 6-7)

8. Ameren's Position

The IPA states that "ICEA recommends conducting the pilot only for ComEd. While the IPA again believes any partial implementation of full requirements is not justified, the pilot may be incomplete if it does not include default service of Ameren Illinois. The differences between the PJM and MISO markets may be significant and if this type of pilot were to be conducted, it would be a lost opportunity not to include Ameren Illinois customers."

Ameren is concerned about this new development and believes it should be rejected. Ameren says the possibility of it being included in a full requirements pilot has never been discussed in this proceeding, the draft Plan, in the IPA workshop held over the summer or any previous discussions with other interested parties. Ameren indicates ICEA has made it clear that its proposed pilot pertains only to ComEd. RESA and Exelon have advocated the same position. The IPA now asserts that Ameren eligible retail customers should be considered as a potential participant in any pilot program. According to Ameren, the IPA provides no rationale other than a vague statement about potential "lost opportunities." (Ameren Reply at 10-11)

Ameren reports it has remained silent on this matter within this proceeding since proposals have never mentioned the possibility of Ameren eligible retail customers being included. Now that the IPA has proposed the possibility, Ameren says it is compelled to address concerns. (Ameren Reply at 11)

While Ameren takes no position at this time regarding the IPA analysis associated with price premiums or prior analysis associated with other interested parties, Ameren supports the IPA recommendation to omit full requirements and load

following products from this Plan as it pertains specifically to Ameren load. (Ameren Reply at 11)

The primary concern of Ameren is that considerable lead time would be required to more fully define the product so that it meets all MISO operational and tariff requirements and also to ensure that contractual and administrative responsibilities are clear. Ameren says the IPA appears to recognize this as well when it reiterates its opinion that no full requirements pilot be included in the Plan, but to the extent the Commission desires to include a full requirements pilot, it should not be included until at least 2016/2017. Ameren agrees that 2016/2017 is the earliest such a pilot could be implemented, but to the extent the Commission desires to include Ameren in a pilot for 2016/2017, such a decision is better suited for a future Plan as opposed to this Plan. (Ameren Reply at 11-12)

Ameren says it will not provide an exhaustive list of implementation concerns at this time. Ameren offers a sample of the issues that its says would need to be addressed, full requirements products specific to Ameren load could involve registration changes at MISO, system upgrades for Ameren's Meter Data Management Agent ("MDMA"), changes in forecasting protocols and how this information is shared with potential suppliers and submitted to MISO for each operating day, determination of scheduling protocols with MISO and with suppliers, development of separate settlement and invoice provisions, consideration of how to address Auction Revenue Rights ("ARRs") and many other issues. Depending on work requirements, Ameren claims it is possible Ameren could see increased systems costs and additional staff needed to accommodate incremental responsibilities associated with contract administration, settlements, forecasting, invoice preparation and check out. Ameren argues that all of this would be done for a very small portion of Ameren. Ameren states that its eligible retail load currently comprises only about 17% of delivery service load and the pilot proposes a 25% allocation to full requirements products. Ameren says any pilot proposal which would incorporate Ameren eligible retail customers would account for approximately 4% of Ameren delivery service load. (Ameren Reply at 12)

Ameren claims prior experience with full requirements associated with the 2006 Supplier Forward Contracts ("SFCs" or "Auction Contracts") suggests that numerous contractual and implementation issues would need to be addressed over a considerable time and through multiple workshops and other forms of communication between interested parties. Ameren says these numerous issues have not been fully vetted and any proposal simply could not be implemented in 2015/2016. (Ameren Reply at 12-13)

9. Commission Analysis and Conclusions

In this conclusion, the Commission will not explicitly address each of the myriad of arguments raised by the parties, as summarized above. Instead, the Commission will briefly summarize those arguments that bear most directly on the Commission's ultimate conclusion on this issue.

The issue before the Commission in this proceeding is whether to adopt ICEA's proposal to modify the Plan such that the IPA would procure FPFR products for 25% of ComEd's forecast load in each of the next four years as a pilot program. ICEA, RESA, and Exelon all believe the procurement of FPFR products will provide benefits to customers that exceed the costs and that the IPA did not adequately respond to the Commission's directive in Docket No. 13-0546 regarding this issue.

The proposal is opposed by the IPA, CUB, and the AG. Ameren opposes the secondary proposal of the IPA to procure FPFR products for Ameren in the event the Commission adopts ICEA's proposal with regard to ComEd. Among other things, these parties argue that the costs of procuring FPFR products do not exceed the benefits.

In Docket No. 13-0546, the Commission's final Order stated in part:

> 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.

As the Commission understands it, the primary new evidence presented in this proceeding is the IPA's analysis of FPFR products in New Jersey and Pennsylvania. The IPA concludes that FPFR prices typically includes a price insurance premium of several dollars per megawatt-hour. ICEA and RESA take issue with the manner in which the IPA quantifies the premium, suggesting that the premium is less than the residual compensation associated with the FPFR product. The Commission also notes that ICEA states "there will be no way to tell what the cost would have been if the 25% FPFR component in the immediate year was instead procured under block and spot approach." (ICEA Reply at 11)

The estimated cost to implement a FPFR procurement is estimated to be between $595,000 and $637,500 for ComEd and as much as $850,000 for both ComEd and Ameren. While most parties agree that the benefit of procuring a FPFR product would be reduced price risk for eligible retail customers, no party has attempted to quantify that benefit. CUB argues that any benefits of price stability associated with FPFR products are unknowable at this time.

The IPA argues that there is insufficient evidence that the benefits exceed the costs to justify adopting ICEA's proposal and deviating from its tradition block-and-spot procurement approach. ICEA and RESA argue that there is insufficient evidence that costs exceed the benefits to justify not adopting ICEA's proposal.

The information relied upon by ICEA, RESA, and Exelon as support for the ICEA proposal is the exact information relied upon in Docket No. 13-0546. The IPA's position, which was adopted in Docket No. 13-0546, is further bolstered by the additional information it provided in this proceeding. Having considered all arguments and information presented by the parties, the Commission concludes that ICEA proposal to include a FPFR procurement in the Plan is not supported by the record and it is rejected.

While the Commission was hopeful that its directive in Docket No. 13-0546 would allow the parties adequate time and information to more fully consider this issue in the current proceeding, the Commission is somewhat disappointed. The Commission notes there was limited useful information regarding the benefits of a FPFR procurement. The IPA suggests this may speak to the challenges inherent in attaining such information. While the Commission recognizes that it cannot reach a truly final disposition of this issue, the Commission wishes to make clear that it is not inclined to consider future years' full requirements procurement proposals absent new arguments supported by an analysis quantifying benefits to eligible retail customers. Nevertheless, the Commission appreciates the input of the parties.

B. Energy Efficiency as a Supply Resource

1. Staff's Position

Staff understands that the aim of the proposal is to reduce, through cost-effective energy efficiency measures and programs, energy demand during "super-peak" time periods, when energy supply is or is expected to be particularly costly. Staff notes the Proposed Plan also presents an alternative, and perhaps simpler, approach of mandating the modification of the Section 16-111.5B third-party RFP process to specifically seek out programs that would reduce demand during peak hours and provide additional incentives for those programs while remaining cost effective. Staff opposes the Proposed Plan's primary recommendation, but generally supports the IPA's alternative proposal. (Staff Objections at 3)

According to Staff, the Proposed Plan's primary approach is not authorized by statute. Staff asserts that neither the PUA nor the IPA Act refers to a supply product called "energy efficiency as a supply resource." The PUA simply refers to two supply products. The IPA, after considering the impact of demand response programs and energy efficiency programs and the supply needs offset by renewable energy resources, proposes to include in its Procurement Plan for meeting expected load requirements not met through existing contracts the following products: (1) demand-response products and (2) standard wholesale products. Staff argues that since neither the PUA nor the IPA Act refers to a supply product called "energy efficiency as a supply resource," and since "energy efficiency as a supply resource" cannot be characterized as either (1) a standard wholesale product or (2) a demand response product, there is no authority for the IPA to include such a product in its Plan. (Staff Objections at 3-4)

Staff further asserts that when the Legislature intends for the IPA to procure energy efficiency, it is very clear on that intent through the language in the law. In Staff's view, because no such authority to purchase energy efficiency as a supply resource is set forth in the PUA or the IPA Act, the Commission should order removal of the IPA's primary EEAASR proposal from its Plan. (Staff Objections at 4)

Staff says while it understands that reducing energy usage in some periods is worth more in avoided costs than reducing energy usage in other periods, reducing usage in specific blocks of time is also likely to be more costly than reducing energy over a broader time frame. Staff claims it is also likely to cost more to verify such energy savings. Even where there are opportunities for programs targeting super-peak blocks to generate relatively higher and positive net benefits (avoided costs less program costs, including any fixed costs), Staff believes the most efficient way to proceed is to exploit such programs until the marginal benefits of each program are no longer greater than the program's marginal costs. That is, the most efficient plan is one where both the programs that affect mostly super-blocks and the programs that do not affect mostly super blocks are each pursued to the point at which further pursuit costs more than it saves. In Staff's view, that is best accomplished if all programs are evaluated side-by-side as part of a portfolio, per Section 16-111.5B of the PUA. (Staff Objections at 4-5)

Staff also believes that the IPA's primary EEAASR proposal places too much emphasis on ensuring against non-delivery of energy savings during fixed blocks of time. While energy efficiency programs have many virtues, Staff contends they are not the same as fixed block energy contracts. Staff asserts that "delivery" is not so easily measured, let alone ensured. Staff says reductions in energy demand are inherently unknowable. According to Staff, that is why the State has authorized large sums to be paid to specialized consultants to estimate the energy savings produced by energy efficiency programs. In practice, Staff says such evaluations have taken months to complete; the end result is still just an estimate, as opposed to a known metered datum. With energy efficiency programs, Staff believes there is no good way to reliably "ensure against non-delivery," as the IPA wants to require of EEAASR. (Staff Objections at 5)

Staff is concerned by the IPA's "principle" that "EEAASR resources may be procured from customers throughout each utility's service territory (not merely from 'eligible retail customers' but also from competitive-class customers)," if the costs of acquiring these EEAASR resources are being recovered only from eligible retail customers through the utilities' electricity procurement cost-recovery riders. Staff states that nevertheless, this will occur if, as the IPA proposes, EEAASR is considered to be a "standard wholesale product," within the meaning of Section 16-111.5(b)(3)(iv) of the PUA. In contrast, Staff says under the IPA's alternative proposal of incorporating these programs under the umbrella of 16-111.5B, their costs would be recovered from "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 through the automatic

adjustment clause tariff established pursuant to Section 8-103 of this Act." In Staff's view, this alternative is the only just and reasonable approach, if the programs are directed toward both eligible retail customers and other customers alike. (Staff Objections at 5-6)

In Staff's view, it is important to understand that if an eligible retail customer reduces electricity consumption at a time when wholesale prices are higher than average that action directly benefits other eligible retail customers since it ultimately reduces the average electricity rate that they pay. However, if some other customer (not an eligible retail customer) reduces energy use when wholesale prices are higher than average, there is no direct benefit to any eligible retail customers. Staff asserts that in all cases, the primary beneficiary of these quantity reductions is the customer participating in the efficiency program. Staff says not only do they get paid automatically for reducing consumption (at the regular retail rate), they also receive additional incentive payments from the utility. Staff claims a reduction in use by such other customers provides no justification for reducing the quantity of supply needed to serve eligible retail customers. (Staff Objections at 6)

Staff insists EEAASR should not be deemed to be a standard wholesale product. Staff believes efficiency programs directed at all customers should not be paid for solely by eligible retail customers. Staff maintains the IPA's primary proposal for focusing energy efficiency efforts on super-peak periods should be rejected. Instead, Staff believes the Commission should generally approve the IPA's alternative proposal. The Plan should encourage DCEO and the utilities to advertise to potential third party vendors wanting to participate in the Section 16-111.5B process that the IPA, DCEO, and utilities: (1) will pay close attention to when third party vendors' programs are expected to produce energy savings; (2) will take into account intra-day and intra-year differences in expected energy prices when valuing program-induced energy savings; and (3) will take into account the relative reliability with which programs produce energy savings during specific time periods. While it is conceivable that a vendor will produce convincing evidence that its proposed program will primarily reduce energy during on-peak hours, Staff advises against the IPA, DCEO, and/or utilities expecting or requiring energy efficiency programs to produce guaranteed energy savings during specific super-peak time periods. (Staff Objections at 6-7)

According to Staff, the Commission should not approve the portion of the IPA's alternative proposal that would require utilities to "[p]rovide an additional financial incentive to these programs for demonstrated peak period kWh reductions" that "could take on the form of the difference between the estimated average energy cost and the estimated energy cost during peak periods." Staff believes it is unnecessary for the Commission to set detailed parameters of efficiency programs, such as the precise level of financial incentives. Staff says the IPA refers to this as an "additional financial incentive," when, arguably, "the difference between the estimated average energy cost and the estimated energy cost during peak periods" should be the financial incentive for such programs. Staff believes such program details can and should be addressed apart from this docket. (Staff Objections at 7-8)

In its Objections, Staff provides specific changes that it recommends be adopted to the Procurement Plan filed by the IPA. (Staff Objections at 8-14)

Staff says it does not agree with the AG's suggestion that the Commission should attempt to find the missing link in the IPA's primary EEAASR proposal. Staff says this is because there is already a competitive market of ARES and "curtailment service providers" who can aggregate the energy efficiency and demand response of non-eligible retail customers and sell negawatts to the RTOs. Presently, Staff says in the RTOs' energy markets, these parties can and do get paid up to the prevailing locational marginal price, while the curtailed retail customers also avoid their retail charges. In the capacity market, Staff states that ARES and curtailment service providers receive payments that may reach the level that generators are paid for making capacity available. Staff contends non-eligible and eligible retail customers, alike, already benefit from these activities indirectly, to the extent to which the RTOs' energy and capacity prices are lower, as a result. (Staff Reply at 4)

In Staff's view, there is no way for the IPA or utilities to compete against the RTOs in the acquisition of these demand-side resources, since the responsibility for dispatching energy and capacity resources to minimize costs and maintain reliability has completely shifted to the RTOs. At worst, Staff claims retail eligible customers would end up subsidizing non-eligible retail customers. At best, Staff asserts each utility could act as a redundant aggregator of aggregators. In such a case, Staff says the utility would sell its double-aggregated demand response to the RTOs. Staff suggests the profitability of such a scheme to eligible retail customers is bound to be elusive, since there is no obvious value added by the IPA and/or the utilities procuring already aggregated demand response of non-eligible retail customers. (Staff Reply at 4-5)

Staff suggests that alternatively, utilities could enter into complimentary financial swaps with ARES and curtailment service providers, whereby the utilities would purchase, for a fixed price, the right to receive the demand response revenues later collected by ARES and curtailment service providers. Staff says any profits could be credited to, and any losses could be recovered from, eligible retail customers. Staff adds that if energy prices or capacity prices increase, eligible retail customers' costs increase directly, but they may receive some offsetting revenue from holding demand response revenue rights. Conversely, if energy prices or capacity prices decrease, eligible retail customers' costs decrease directly, but they may sustain a loss from holding demand response revenue rights. According to Staff, in a very indirect and complicated way, eligible retail customers' net costs of electricity would be less susceptible to future changes in wholesale energy and capacity prices. Staff asserts whether or not such a scheme would constitute a hedge for ARES or their retail customers, or curtailment service providers or their retail customer partners, would depend on the nature of their contracts with one another (currently unregulated). Staff believes there is no reason for the utilities to become involved in such convoluted hedging schemes, since they already have simpler, more direct and effective means to achieve the same ends. (Staff Reply at 5)

According to Staff, the IPA rejects the fact that the IPA would still have to procure the exact same amount of supply resource for the eligible customers, and the savings would simply accrue to the non-eligible customer. Staff claims the IPA fails to see that most non-eligible retail customer load is interval metered, and that a reduction in demand by one of these customers reduces that customer's capacity obligation and peak energy supply requirements by exactly the same amount as it reduces the total zonal capacity obligation and peak energy supply requirements. Staff says the customer is the only direct beneficiary of its actions. Staff asserts that with the advent of smart meters, soon, all customers' load will be interval metered, and all customers will benefit 100% from their own peak demand reductions (or pay 100% of the increased cost associated with their own peak demand increases). Staff argues all customers have the option of taking hourly-priced service, now, if they wish to receive 100% of the benefits from their ability to control their own load. (Staff Reply at 6)

Staff maintains that taking DRIPE into account -- for purposes of determining the cost-effectiveness of energy efficiency programs (or for justifying economic policies in any market) -- is inappropriate, contrary to the goal of maximizing economic efficiency, and inconsistent with the definition of the total resource cost test found in the IPA Act. (Staff Reply at 6)

Staff says it, ComEd, and Ameren agree that EEAASR is not a "standard wholesale product" under Section 16-111.5(b) of the PUA. The IPA, AG and CUB disagree, arguing that EEAASR can meet the definition of "standard wholesale product." Staff claims there is nothing new in the record in this docket regarding the lack of authority for the Commission to approve IPA procuring EEAASR. Staff states the position of Staff, ComEd, and Ameren is consistent with the Commission's prior order in Docket No. 10-0563. In its final order in that proceeding, the Commission concluded that there is no express authority for the IPA to procure energy efficiency as a resource, noting:

> The IPA Act contains only a few references to energy efficiency, none of which expressly grant the IPA authority to procure it as part of any procurement Plan.
>
> ***
>
> Similarly, the PUA contains no express language authorizing the IPA to acquire energy efficiency through the Plan.
> (Staff Reply at 6, citing Docket No. 10-0563, Order at 42)

Staff states neither the IPA, AG nor CUB tenders any new facts or arguments in the instant case to persuade the Commission to reverse its findings in Docket No. 10-0563. Staff maintains the primary EEAASR proposal by the IPA must be rejected since there is no authority to approve it. Staff recommends the Commission approve the IPA's alternative proposal. (Staff Reply at 6)

Staff agrees with Comverge that the energy efficiency rules should apply for the EEAASR Alternative procurement. If the Commission agrees that the energy efficiency rules should apply for the EEAASR Alternative procurement, then Staff believes the Commission need not specify the hours that would define a peak period for purposes of the EEAASR Alternative because the Commission-adopted Illinois Technical Resources Manual ("IL-TRM") already specifies a peak period for use in Illinois. Staff says the IL-TRM Version 3.0 specifies that the "summer peak period is defined as 1:00-5:00 PM Central Prevailing Time on non-holiday weekdays, June through August." Staff says while the months specified for the peak period in the IL-TRM are consistent with the peak period months proposed by the IPA for the EEAASR procurement, the IPA proposed the peak period times would be from 3:00-7:00 PM (CST) on weekdays, whereas the IL-TRM specifies 1:00-5:00 PM (CPT). The summer peak periods specified in the IL-TRM are for the purpose of establishing summer peak coincidence factors demand (kW) savings for each energy efficiency measure in the IL-TRM, of which those would be used in the TRC analysis for the measures. The IL-TRM also defines load shape peak energy definitions for purposes of assigning energy savings (kWh), those are defined as 8AM - 11PM CPT, weekdays, no NERC holidays all year. (Staff Reply at 9)

Should the Commission desire the third-party vendors of the peak demand reduction programs to deviate from the IL-TRM, Staff believes the Commission should make this clear in the final Order in this proceeding. Should the Commission desire a workshop be held to determine what peak period should be used in the RFP for peak demand reduction programs, Staff also believes the Commission should make this clear in the final Order and also specify whether a consistent peak period across utilities is required in order to remove a potential issue from contention. (Staff Reply at 9-10)

The AG indicates that while it agrees with ComEd that DSMore can support hourly analysis of avoided costs, it is the AG's understanding that the DSMore TRC analyses do not full reflect hourly simulations. Staff agrees with the AG. To the best of Staff's knowledge the DSMore analysis of the Section 16-111.5B energy efficiency programs have not fully utilized the hourly avoided costs simulations feature available in DSMore. That being said, Staff is not aware of any ComEd bid submittals that emphasized they would save energy during peak periods. Staff does not believe the bids have been analyzed unfairly to date in regard to peak periods. Staff says the benefits, complexities, and costs associated with requiring such detailed TRC modeling can be addressed at the 2015 TRC workshops. (Staff Reply at 10)

The IPA states that the definition of a standard wholesale product cannot be static, but should change as the products traded in wholesale markets change. Staff agrees that the definition of a standard wholesale product should change as the products traded in wholesale markets change. Staff asserts the definition should not be so flexible as to admit products that clearly are not standardized, and energy efficiency programs are the antithesis of standardized. Staff maintains the SAG regularly debates a number of aspects of each of the unique energy efficiency programs, and the utilities

and their vendors customize them in minute detail. Staff says Even the evaluation, measurement, and verification of these programs must be customized, primarily since the actual energy reduction must be measured relative to an inherently unknowable baseline. (Staff RBOE at 4-5)

Staff opposes the IPA's proposed language changes set forth on page 7 of its Brief on Exceptions involving the IPA's alternative proposal that would require such workshops beginning in January and concluding by mid-February to allow workshops to inform the development of RFPs. Staff opposes the IPA's language changes because it adopts the IPA's alternative proposal without the Staff modification that eliminates the extra financial incentive. (Staff RBOE at 9)

Staff understands that Ameren plans to release a draft version of its Section 16-111.5B RFP by early January and issue the final RFP by the end of January. Staff suggests wrapping up the workshops by mid-February, as the IPA proposes, would be too late. Given the IPA held workshops regarding EEAASR earlier this year, and given the fact that the IPA wants workshops on this issue to conclude quickly, Staff suggests that it might be more appropriate for the IPA to host the workshops concerning the RFPs and the IPA's alternative proposal. Alternatively, Staff suggests that when ComEd and Ameren issue their draft RFPs for stakeholders review, they could include the IPA's alternative proposal, as modified by the Commission's Order in this docket, in those draft RFPs. Staff says interested parties would then be able to provide written input on those draft RFPs for the utilities' consideration. (Staff RBOE at 10)

2. ComEd's Position

According to ComEd, the Plan cites no authority for the EEAASR proposal. ComEd says the Commission has already determined that energy efficiency proposals such as this cannot be brought under Section 16-111.5 of the PUA. The General Assembly, ComEd claims, subsequently concurred in the Commission's construction of Section 16-111.5, and separately created new Section 16-111.5B as the exclusive vehicle through which incremental energy efficiency could be procured in conjunction with the annual procurement process under Section 16-111.5. In ComEd's view, the EEAASR proposal does not satisfy the mandatory criteria set forth in Section 16-111.5B. (ComEd Objections at 3)

ComEd asserts the Plan fails to demonstrate that the EEAASR proposal satisfies the required TRC Test and would unlawfully procure energy efficiency from customers that are outside of the scope of Section 16-111.5B. ComEd also contends the EEAASR proposal would unfairly and unlawfully seek to recover all of its costs from just a small subset of the customers from whom energy efficiency is being procured. (ComEd Objections at 3)

ComEd also argues that the General Assembly has not amended the original Section 16-111.5 to accommodate EEAASR. In ComEd's view, the Commission's conclusions in Docket No. 10-0563 remain undisturbed – Section 16-111.5 does not

authorize energy efficiency procurement under its terms, and, in any event, it is unclear how energy efficiency could be considered a "standard wholesale product" under Section 16.111.5. ComEd believes the EEAASR proposal also runs afoul of Section 16-111.5's directive that the procurement be limited to eligible retail customers – a subset of ComEd's customers eligible to take fixed-price bundled service from ComEd and are in fact doing so. ComEd says the proposal would permit procurement from all customers in the utility's service territory, including large industrial customers, which would do nothing to reduce the amount of supply needed to serve eligible retail customers. ComEd also complains that these eligible retail customers would be required to pay for the efficiency procured from these large customers despite receiving no benefit from it. (ComEd Objections at 4, Reply at 2-3)

ComEd states while the IPA "believes it has the authority" to implement the EEAASR proposal, the Plan also includes an EEAASR alternative proposal brought under and subject to Section 16-111.5B. (ComEd Objections at 4)

ComEd maintains that proposals to procure incremental energy efficiency in conjunction with the Plan must be brought under Section 16-111.5B. ComEd says because the IPA did not present the alternative proposal in its Draft Plan, this is the first time that stakeholders have had an opportunity to review and comment on it. ComEd generally supports the EEAASR alternative proposal and its consideration within the parameters of Section 16-111.5B. ComEd asserts, however, that the brevity of the proposal also leaves unanswered several key questions and concerns regarding its implementation. As a result, ComEd agrees with the Plan's recommendation that the workshop process to be initiated around TRC Test issues also include a discussion of how the EEAASR Alternative proposal might be incorporated into the existing Section 16-111.5B request-for-proposals process. (ComEd Objections at 5)

It is unclear to ComEd whether the alternative proposal calls for another RFP separate from the RFP already proposed for procurement of incremental energy efficiency under Section 16-111.5B. ComEd notes that the utilities' RFP timelines are already quite aggressive under the existing solicitation process, and it is difficult, if not impossible, to see how a separate RFP process could be conducted. ComEd therefore recommends that the alternative proposal be accommodated within the existing RFP simply by adding a paragraph to address the targeted programs component. (ComEd Objections at 5-6)

ComEd says it is important to understand that its proprietary cost-effectiveness tool – DSMore – already conducts cost-benefit tests using hourly values, as opposed to an average annual value. This means that a program or measure that only saves energy during certain prescribed hours is already being modeled with this tool as the alternative proposal recommends. Moreover, ComEd states that DSMore runs multiple scenarios that address varying combinations of weather and market prices, which allows ComEd to consider the impact of warmer or cooler weather, as well as higher or lower future energy prices, on TRC results. As such, ComEd believes no modifications

need to be made to ComEd's DSMore cost-effectiveness analysis to implement the alternative proposal. (ComEd Objections at 6)

ComEd states that Section 16-111.5B's third party RFP process does not prescribe incentive levels, and ComEd recommends that this framework remain unchanged. ComEd believes it is important that any program that is cost-effective under the TRC Test and provides incremental savings under Section 8-103 of the PUA would be eligible. Because DSMore properly evaluates the time-based savings of programs, ComEd says the TRC Test result will already value the peak hour savings correctly. In ComEd's view, the determination of appropriate incentive levels should remain within the purview of the third party that is making the proposal to implement the program. (ComEd Objections at 7)

ComEd maintains that Section 16-111.5B provides for procurement of cost-effective energy efficiency measures to achieve energy savings that are "incremental" to the energy savings mandated by Section 8-103. As a result, ComEd says Section 8-103 programs always serve as a baseline and reference point for the Section 16.111.5B process and procurement. ComEd asserts the recommendation that programs under the EEAASR alternative proposal be "at least three years in duration" would mean that these new Section 16-111.5B programs would involve bids and contracts for periods that extend at least two years past the programs approved in ComEd's current Section 8-103 plan. As such, ComEd says the required determination as to whether these programs under the alternative proposal are "incremental" could not be made because the Section 8-103 programs will not yet have been determined. Accordingly, ComEd recommends that the alternative proposal's programs not exceed the length of the current Section 8-103 plan programs. (ComEd Objections at 7-8)

Based on its concerns, ComEd concurs with the Plan's recommendation that issues associated with the EEAASR alternative proposal could be further explored during the workshop process convened to discuss TRC Test issues. In ComEd's view, this is especially true given that stakeholders only first heard of the alternative proposal in the September 29, 2014 Plan. ComEd believes the concerns it identified likely are not unique to it, and ComEd anticipates that Ameren, Staff and others may share these concerns or identify others. As a result, at this juncture ComEd recommends that the Commission direct that the EEAASR alternative proposal be taken up in the workshops and decline to order specific modifications to the Section 16-111.5B RFP process at this time. (ComEd Objections at 8)

According to ComEd Section 16-111.5B, its legislative history, and Commission practice mandate rejection of the Plan's original EEAASR Procurement Proposal. ComEd says the IPA first proposed EEAASR in 2010 as part of its 2011 Plan, the Commission considered the proposal, but ultimately concluded that energy efficiency could not be considered under Section 16-111.5 and, in any event, did not appear to be a "standard wholesale product" as required by that Section. (ComEd Objections at 8-9)

ComEd states that during 2011, the General Assembly subsequently enacted the Energy Infrastructure Modernization Act ("EIMA"), which amended Section 16-111.5 as well as added new Section 16-111.5B to the PUA. While the legislature's amendments to Section 16-111.5 did not address energy efficiency, ComEd claims new Section 16-111.5B establishes a specific evaluation and proposal process for the procurement of additional energy efficiency in conjunction with the annual procurement process under Section 16-111.5. According to ComEd, this energy efficiency procurement is limited to the specific customer groups and other criteria set forth in Section 16-111.5B, and must be incremental to Section 8-103's energy efficiency portfolio. (ComEd Objections at 9-10)

In ComEd's view, when the Commission practice and legislative history are duly considered, two conclusions can be reached: (i) the General Assembly has acquiesced in (or "affirmed") the Commission's interpretation of Section 16-111.5 (i.e., Section 16-111.5 does not provide for procurement of energy efficiency), and, therefore, (ii) the only means by which efficiency may be procured in conjunction with the annual procurement process is through satisfying the requirements of Section 16-111.5B. ComEd argues that the IPA's EEAASR proposal can only be approved insofar as it complies with the requirements of Section 16-111.5B. (ComEd Objections at 10-11)

ComEd maintains that Section 16-111.5B of the PUA exclusively governs the IPA's procurement of energy efficiency measures. ComEd complains that neither the IPA nor any other party offers EEAASR as one of the projects to be evaluated for inclusion in this year's Plan under Section 16-111.5B. ComEd asserts the detailed analyses required thereunder either were not performed or have not been presented. ComEd also contends no showing has been made that the EEAASR proposal passes the TRC Test, as required by Section 16-111.5B. ComEd says Section 16-111.5B sets forth a thorough set of requirements that must be satisfied prior to including incremental energy efficiency within a procurement plan. (ComEd Objections at 11)

ComEd says the "cost-effective" standard runs throughout all stages of the Section 16-111.5B process – the IPA can only include "cost-effective" programs and measures in the Plan, and programs and measures ultimately approved by the Commission must be cost-effective and otherwise satisfy the requirements of Section 8-103. ComEd also says Section 16-111.5B further clarifies that "cost-effective" has the meaning set forth in Section 8-103(a), which in turn states that "'cost-effective' means that the measures satisfy the total resource cost test" as defined in Section 1-10 of the IPA Act. 220 ILCS 5/8-103(a). (ComEd Objections at 13)

ComEd complains no showing has been made that the EEAASR proposal satisfies the TRC Test, or that any TRC Test has even been performed. ComEd says the Plan notes that "the utilities are required to provide, along with their load forecasts, an assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan" and that "[b]oth Ameren Illinois and ComEd have provided this information … ." Because Ameren's and ComEd's submissions are designed to already include all cost-effective energy efficiency measures that satisfy the

TRC Test, ComEd claims it is notable that EEAASR is not included among these measures. One conclusion ComEd draws from this evidence is that the additional energy efficiency measures procured by the IPA for super-peak blocks would likely fail to pass the TRC Test and otherwise contravene Section 16-111.5B. (ComEd Objections at 14)

According to ComEd, Section 16-111.5B limits the cost recovery for such incremental energy efficiency programs to the same group of customers who are offered the programs, yet the EEAASR proposal would presumably recover the costs of EEAASR through the supply charge applicable to only the utility's eligible retail customers. ComEd claims this not only violates the statute, but also unfairly forces eligible retail customers to pay for reductions in usage that do not impact or benefit such customers. (ComEd Objections at 15)

For example, ComEd argues that because procurement of energy efficiency from a large industrial customer would not reduce the amount of supply needed to serve eligible retail customers, the EEAASR proposal fails to qualify as an alternative means of procuring supply to serve eligible retail customers. (ComEd Objections at 17)

In ComEd's view, this "mismatch" is further heightened when cost recovery is considered. ComEd says because Section 16-111.5 limits its applicability to eligible retail customers, the cost recovery mechanism (Rider PE – Purchased Electricity) similarly limits cost recovery to eligible retail customers. To ComEd, this means that eligible retail customers would be required to pay for procurement of energy efficiency from all retail customers in a utility's service territory despite their inability to realize any reduced energy consumption or benefit from energy efficiency procured from commercial and industrial customers. ComEd says the EEAASR proposal would require that eligible retail customers subsidize energy efficiency for these larger customers. (ComEd Objections at 17)

ComEd claims the General Assembly carefully avoided these mismatch and subsidization problems altogether in Section 16-111.5B. ComEd says the legislature ensured parity between (a) the customers to whom energy efficiency would be offered, and (b) the customers who would pay for such efficiency. ComEd is not surprised that energy efficiency proposals outside of this legislatively prescribed framework (such as EEAASR) will run afoul of Section 16-111.5 and associated tariffs. ComEd claims the General Assembly never intended that such proposals be shoehorned into Section 16-111.5. (ComEd Objections at 17-18)

ComEd reports that Section 16-111.5(d)(4) of the PUA provides that "[t]he Commission shall approve the procurement plan … if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." ComEd complains the EEAASR proposal fails to make any concrete showing that it would satisfy the "lowest total cost over time" standard. While the IPA postulates that EEAASR "could potentially constitute a lower cost alternative than

comparable supply," ComEd claims there is nothing to support this contention. In ComEd's view, the IPA implicitly acknowledges that EEAASR is a high cost rather than low cost resource when it proposes to ban generation/supply side participants from competing. ComEd argues that not only is this discriminatory, it highlights the fact that the EEAASR proposal cannot meet the "lowest cost" requirement of the PUA. ComEd suggests one of the reasons for this could be that the procurement block size is very small (100 kilowatts vs. 25,000 kilowatts for the wholesale blocks the Commission has approved) resulting in the relative weight of administrative costs being more burdensome for a proposal of this type. ComEd says the legislature implicitly acknowledges this fact elsewhere in the IPA Act when it mandates a minimum aggregation of 1 megawatt capacity for procuring distributed generation, which is also small in size. ComEd also complains that no rationale is presented for why EEAASR participants will sell their product to the IPA at significantly lower prices than they would receive from the PJM markets which is the benchmark for savings that should be used. (ComEd Objections at 18-19)

ComEd argues that the EEAASR proposal is too speculative and undeveloped to be implemented. ComEd says only one page attempts to lay out any substance to the proposal, but this is too inadequate and leaves important questions unanswered. Without significantly more specificity and supporting data from the IPA, ComEd believes there can be no reasonable way to conclude that incurring additional procurement costs to buy very small amounts of energy outside of the PJM market in which ComEd operates can be expected to lower, rather than raise, costs to ComEd customers. (ComEd Objections at 19)

ComEd claims some of the same concerns identified by the Commission regarding the 2010 proposal are present in the 2014 proposal. ComEd says the proposal concedes that it remains to be determined how the proposal would avoid "overlap" with existing energy efficiency programs offered under Sections 8-103 and 16-111.5B. Given that this concern was first identified by the Commission four years ago in its Order in Docket No. 10-0563, ComEd believes it is unlikely that the issue can be resolved in the near future. ComEd claims many critical issues that would have to be resolved before moving forward including "Vendor/Program Qualification," "Product Definition," "Credit Requirements and Non-Delivery Penalties," and "Verification." In ComEd's view, the existence of so many serious and unresolved issues points to the conclusion that the EEAASR proposal, if it is to be considered at all, must be proposed under Section 16-111.5B and meet the requirements thereunder. (ComEd Objections at 19-20)

According to ComEd, another key issue involves how the EEAASR proposal would work with PJM. ComEd assumes that, like its standard wholesale product suppliers, the EEAASR supplier would deliver MWs to ComEd's PJM account, which would reduce the amount ComEd needs to purchase from the market for its supply customers. If this is not the case, however, ComEd's fixed supply customers would receive no benefit for whatever payment is made to the supplier. (ComEd Objections at 20)

If this product is truly a pure energy efficiency proposal rather than a standard wholesale product delivered to ComEd's PJM account, then ComEd says it would need to be procured from only ComEd fixed supply customers in order to provide any value to the customers paying for the EEAASR. To ComEd, this means the IPA, ComEd, or supplier would need to incur the expense of verifying that promised load reductions are delivered and that they are only from ComEd's fixed supply customers, which means constant monitoring of customer switching. In this case, ComEd says fixed supply customers would benefit directly by using less costly energy; however, the price that could be paid for this energy would be significantly less than the market price. ComEd asserts it is actually the market price less the average cost of supply otherwise being paid by ComEd's customers. It remains unclear to ComEd why the EEAASR proposal would be attractive to potential suppliers or save money for ComEd customers after all procurement and administration costs are considered. (ComEd Objections at 20-21)

ComEd states that only CUB filed Objections in support of the EEAASR proposal, but, ComEd asserts, like the Plan, cited no authority for the proposal. ComEd claims CUB's recitation of the many open issues regarding the EEAASR proposal – without any meaningful resolution of those issues – further highlights that this concept cannot be considered, much less adopted, at this time. (ComEd Response at 2)

ComEd notes that with respect to the EEAASR Alternative proposal, Staff generally joins its support for further exploration of the proposal, and agrees with ComEd that it cannot be adopted as proposed in the Plan (opposing, for example, the new requirements for an additional financial incentive). ComEd indicates Ameren ultimately concludes that too many open issues exist with the Alternative to support it at this time. While ComEd agrees with Staff and Ameren that the current Alternative proposal contains too many outstanding issues to be adopted as proposed in the Plan, ComEd is willing to further discuss the proposal through the workshop process. (ComEd Response at 2)

ComEd states although the IPA's Response glosses over this Commission practice, legislative history and case law, and instead continues to insist that EEAASR may be considered under Section 16-111.5, the IPA cites no support for its claims. While the AG claims that any demand side resources would pass the TRC Test because, by definition, they will be the lower cost alternative, ComEd believes this claim can quickly be proven untrue. ComEd says EEAASR is only concerned about the offered price of the energy efficiency as compared to a supply price benchmark, and therefore completely ignores that the TRC Test also considers the cost incurred by the implementer to install the measure. ComEd asserts one could install very expensive measures for reasons that do not involve saving energy, and then offer the energy efficiency savings in EEAASR as an additional compensation mechanism against the equipment investment. ComEd contends that not only would the measure fail to pass the TRC Test, but the energy savings could not be counted under evaluation, measure and verification procedures because the implementer is a "free rider", meaning that the measure would have been installed with or without the incentive (here, the auction

revenues). ComEd says because the savings would have occurred regardless of the auction revenues, the energy efficiency savings cannot be counted. (ComEd Reply at 3-4)

The IPA argues that its proposal can be brought under Section 16-111.5 because it is a "standard wholesale product." According to ComEd, the IPA provides no market examples or literature to support this claim, and only asserts that the absence of any express exclusion of energy efficiency under Section 16-111.5 is sufficient to support its proposal. ComEd claims nowhere in Section 16-111.5 does the Commission set forth a long list of everything that is not a standard wholesale product, but this does not mean that anything goes simply because it has not been explicitly excluded. (ComEd Reply at 4-5)

ComEd states that while the AG, on the one hand, encourages the Commission to take a broader, "21st century view" of a "standard wholesale product," it also concedes, on the other hand, "that there are very significant and potentially difficult issues to resolve, and mechanisms to be created, to make the IPA electricity procurement of 'negawatts' efficient and effective." The AG therefore concludes that it "agree[s] with the Parties that these details have not been fully worked out and articulated sufficiently by the IPA to unconditionally approve the EEAASR for 2016 procurement." ComEd says while this position is consistent with the concerns raised by Staff, Ameren, and ComEd, the AG nevertheless encourages the Commission to support the EEAASR concept. In ComEd's view, a concept shown to be unsupported and incapable of implementation under existing law cannot be "explicitly support[ed]", as the AG suggests. ComEd believes the EEAASR concept should be rejected in this docket with no provision for future consideration as a matter of law. (ComEd Reply at 5)

The IPA and CUB also claim that the procurement of energy efficiency products in venues such as PJM and ISO New England ("ISO-NE") supports energy efficiency procurement here. In ComEd's view these separate procurements highlight even more complications with the EEAASR proposal. ComEd says it already offers its energy efficiency into the PJM Capacity Market (the "Reliability Pricing Model," or "RPM"). ComEd says the EEAASR proposal does not address how to ensure that double counting does not occur, first by load-serving entities through the RPM and again through EEAASR. ComEd also says neither the IPA nor CUB resolves the many other evaluation, measurement and verification issues identified in Staff's Objections. ComEd claims CUB makes only a passing reference to "industry best practices" and "advanced metering infrastructure", but no specific literature is cited or explanation provided as to how these "practices" or technology address Staff's concerns. (ComEd Reply at 6)

ComEd finds it odd that the IPA refuses to accept the obvious point that purchasing energy efficiency from industrial customers within ComEd's service territory does not reduce the energy requirements of utility-supplied eligible retail customers. ComEd says the IPA claims, without any support, that "[p]rocuring peak demand reductions from any customer within the utility footprint – reducing demand – reduces the overall capacity obligations and peak energy supply costs for eligible retail

customers, regardless of whether that energy efficiency is actually procured from eligible retail customers." In ComEd's view, this is incorrect. ComEd says the PJM capacity obligations for eligible retail customers will not be reduced by a single kilowatt if the IPA purchases energy efficiency from industrial customers. ComEd asserts its eligible retail customer energy requirements will only be reduced if the IPA procures energy efficiency from eligible retail customers. (ComEd Reply at 6-7)

According to ComEd, contrary to the AG's optimism that some sort of "mechanism" could overcome this obstacle, no amount of creativity can or should overcome a clear statutory framework that has been in place for years – Section 16-111.5 is limited to procurement of power and energy supply for eligible retail customers. ComEd believes it is not intended as a "mechanism" to lower costs generally for all customers through the procurement of energy efficiency measures – that is the purpose of Section 8-103 and, to a lesser extent, Section 16-111.5B of the PUA. ComEd also believes the AG's claim that it should not matter from whom demand side resources are procured also runs contrary to Section 16-111.5. ComEd notes demand response resources (a "demand side resource"), which the IPA is authorized to consider and procure under Section 16-111.5, must be procured from eligible retail customers. (ComEd Reply at 7-8)

In its Objections, Staff, ComEd and Ameren identified a variety of issues that would still need to be worked through before the Alternative could be adopted. ComEd recommended that the proposal continue to be discussed and developed through workshops. (ComEd Reply at 8-9)

Comverge, consistent with Staff's Objections, proposes the requirement that financial incentives be increased would be eliminated. In ComEd's view, even with this change (which ComEd supports), outstanding questions remain. ComEd states as a practical matter it is now far too late to conduct a solicitation under Section 16-111.5B for the 2015 delivery year. With or without workshops, ComEd believes 2016 is the earliest that this proposal could be placed into effect. According to ComEd, the other issues identified by Ameren and ComEd have not yet been resolved. ComEd maintains that its TRC Test tool, DSMore, already reflects time differentiated avoided costs. ComEd says in its Response, the AG notes that it is "unsure exactly how ComEd develops and uses its avoided costs." ComEd states given that the AG, IPA and CUB are unsure how DSMore works, the parties should explore this and other issues during workshops, with the goal of presenting a more fully developed proposal in the next Plan filing. (ComEd Reply at 9)

With respect to Comverge's Response in particular and its criticism of the utility solicitation process, ComEd believes that Comverge may have misunderstood the nature of the product the IPA is proposing to purchase. ComEd says Comverge refers to EEAASR "peak demand reductions" and "targeted peak demand reduction programs", and goes on to blame ComEd for having not included a request for these demand-type programs within its solicitation for energy efficiency proposals. ComEd's understanding is that the IPA is requesting to hold an energy procurement rather than a

peak demand/capacity procurement. ComEd states that when it issued its solicitation for energy efficiency proposals, a proposal such as EEAASR could have been submitted if it were cost effective. (ComEd Reply at 9-10)

According to ComEd, EEAASR cannot be proposed under Section 16-111.5; Section 16-111.5B is the exclusive statutory provision through which incremental energy efficiency can be procured in conjunction with the Plan. (ComEd RBOE at 3-4) ComEd also claims neither CUB nor the IPA claims that the EEAASR proposal is proposed under, or complies with, Section 16-111.5B. (ComEd RBOE at 4) ComEd contends that even if EEAASR could be proposed under Section 16-111.5 (and it cannot), it is not a "standard wholesale product" and violates statutory cost-recovery provisions. (ComEd RBOE at 5-6)

ComEd believes the Proposed Order correctly concludes that the alternative EEAASR proposal should be further developed during workshops. (ComEd RBOE at 6-7)

3. Ameren's Position

Ameren believes the IPA's primary EEAASR procurement proposal leaves many key issues unexplained or unresolved and should be rejected. While Ameren appreciates the IPA's request of the interested stakeholders, including the utilities, to provide input and work towards resolution of many of these issues, Ameren believes the issues with the IPA's EEAASR proposals are too fundamental to be allowed. (Ameren Objections at 9)

Ameren is not certain what the proposed EEAASR products are or whether they meet the definition of "standard wholesale products" for which the IPA can procure under the PUA. Although the Plan appears to be seeking this determination by the Commission in a footnote on page 70, Ameren claims there is no explanation as to why the products to be procured by the proposed EEAASR procurement meet the statutory definition of "standard wholesale products." Ameren contends that approval of EEAASR procurement under Section 16-111.5 requires a full vetting of whether the products at issue meet the requirements of the PUA before the procurement event is approved, not the other way around. (Ameren Objections at 9)

Ameren complains that the Plan does not provide a detailed analysis of whether the proposal meets the IPA goal 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" nor is the total quantity of the proposed procurement defined in the Plan. Even if EEAASR were a viable product under Section 16-111.5, Ameren believes it should then be compared to a solicitation of comparable supply resources that achieve the same super peak hedge. Ameren also says that even a supply super peak product might be difficult to benchmark and procure. Ameren also complains no detail has been provided as to how the IPA can or would choose the mix of EEAASR and supply side resources that

achieve the least cost to customers. Ameren believes such details should be provided before the Commission approves a procurement event and would be consistent with the law and how the IPA and the Commission treat planned procurement of other products. (Ameren Objections at 10)

Ameren notes the Plan is already hedging July/August on peak at 106% of average load in an attempt to reduce risk across the super peak. It appears to Ameren that the EEAASR procurement proposal could result in redundant hedges in the summer. Ameren complains the Plan is silent as to how the IPA will avoid such redundancies. (Ameren Objections at 10)

According to Ameren, while the Plan acknowledges that significant design issues remain, the IPA nonetheless asks for Commission pre-approval based on the understanding that the IPA will hold workshops in the spring of 2015 to resolve any remaining issues. Ameren notes if the IPA determines that the product is not ready for solicitation by late 2015, the solicitation could be canceled after consultation with Commission Staff, Procurement Administrator and Procurement Monitor and a subsequent Commission filing requesting such cancelation that would occur no later than August 2015. In Ameren's view, this proposal raises significant concerns as to whether there is enough time for full vetting among interested parties of the many known issues that have been identified. Ameren also complains that this proposed process desires to exclude Ameren from the decision as to whether to ultimately proceed with a procurement event, even though the Plan appears to contemplate that the utilities would be the counterparty to resulting contracts. (Ameren Objections at 10-11)

Ameren says although none of its energy efficiency is currently registered at MISO as a resource, the Plan is silent as to whether its EEAASR procurement proposal would satisfy MISO requirements should energy efficiency be determined to be a supply resource and registered at MISO in the future. (Ameren Objections at 11)

Ameren notes energy efficiency is already procured pursuant to Section 16-111.5B of the PUA and it is unclear to Ameren whether the EEAASR procurement proposal comports with the existing requirements set forth in the Act for energy efficiency procurement. Ameren says if EEAASR is determined to be "cost-effective" under the PUA, it is left unexplained why energy efficiency procurement should not simply be done under Section 16-111.5B. (Ameren Objections at 11)

Ameren claims the Plan's intention to procure energy efficiency from customers throughout each utility's service territory (including from "competitive class customers") and not only from a utility's "eligible retail customers" appears to contradict the specific requirements of Section 16-111.5B, which limits energy efficiency procurement to Ameren's "eligible retail customers" and raises additional unanswered questions of how and from whom the costs would be recovered for such procurement. (Ameren Objections at 11-12)

According to Ameren, the Plan does not resolve the many complicated and technical issues that would result from the impact of the proposed EEAASR procurement on the other energy efficiency being offered to customers in accordance with the requirements of Sections 16-111.5B and Section 8-103 of the PUA. Ameren says having energy efficiency be both a demand side management resource and supply resource would require yet another planning, implementation and verification framework subject to the rules of supply, which could potentially include stricter credit requirements, non-delivery penalties, near-immediate verification of peak period savings and the use of "gross" savings instead of "net" savings. Ameren complains the Plan provides no detailed analysis as to how the EEAASR procurement would impact the planning, savings, cost-effectiveness and implementation of the currently offered energy efficiency programs, each of which is important given the requirements (including savings requirements) imposed on the utilities under Sections 8-103 and 16-111.5B of the PUA. Ameren believes resolution of these critical issues is necessary to ensure utilities can effectively deliver energy efficiency to the market subject to the requirements of the PUA. (Ameren Objections at 12)

Ameren says the Plan itself recognizes that significant and fundamental issues still need to be resolved prior to EEAASR procurement and suggests that workshops be hosted in spring of 2015 (and completed by summer of 2015) to accomplish this. Notwithstanding the ambitious schedule proposed by the IPA, Ameren is concerned that many of the unresolved issues cannot be resolved by agreement of the interested stakeholders only. Instead, Ameren believes Commission approval would be necessary to ensure compliance under the PUA (for example, whether the final "products" procured comport with the PUA). (Ameren Objections at 12-13)

Ameren notes the IPA requests that the Commission consider an alternative proposal whereby the Commission directs the utilities to modify their respective Section 16-111.5B third party RFPs. Specifically, the IPA requests that the utilities: (1) include requests for targeted programs that could identify and demonstrate reductions during peak periods; (2) perform TRC test calculations for these targeted programs using a time-specific avoided energy cost; (3) provide additional financial incentive to these programs for demonstrated peak period kWh reductions; and (4) require the programs be of at least three-years in duration. Ameren believes the second EEAASR procurement proposal should also be rejected. Ameren claims many of the issues raised by the first proposal, such as the scope of customers to be served by the EEAASR procurement and how verification of supply savings could be timely accomplished, are not remedied by the alternative. (Ameren Objections at 13)

Ameren says the utilities would need further specificity as to the types of targeted bids that should be sought (for example, what "peak periods" should be targeted) through the RFP process so that the utilities can adequately analyze the received bids for compliance with the RFP. Ameren complains the Plan is currently silent on such details. While the provision of additional financial incentives to program implementers who demonstrate reductions during peak periods is understandable, Ameren notes that it is the implementers themselves who set the incentive levels in the bids, not the utility.

Ameren also believes clarity would be needed as to which "rules" apply to EEAASR procurement: traditional supply side rules or the demand side management ("DSM") rules currently in place for energy efficiency programs. As a supply resource, Ameren says the supply rules would have to apply to EEAASR. Ameren states that applying the rules of supply would include such things as stricter credit requirements and non-delivery penalties for vendors; the comparison of the EEAASR procurement cost to other supply options; a prompt verification of gross savings, particularly for "peak periods;" and could cause confusion to customers as to whether they are eligible for such program incentives or not. In Ameren's view, the Plan does not adequately address or resolve any of these issues nor identify a need for the Commission to do so at this time. (Ameren Objections at 13-14)

In Ameren's view, the EEAASR proposals contained in the Plan are premature and give rise to too many fundamental issues that, when left unresolved, would create significant issues for procuring, implementing and verifying any achieved supply savings. Ameren recommends that the Commission reject the EEAASR proposals and remove Section 7.1 from the Plan in its entirety. (Ameren Objections at 14)

CUB's comments address the various aspects of the primary proposal, including the use of Super Peak Blocks; Multi-Year Contracts; 100 kW blocks; timing for procurement and delivery; optionality; definition of "wholesale supply product;" credit requirements and non-delivery penalties; and verification, and go on to provide general policy-based support for each. In Ameren's view, policy statements do not provide any substantive explanation or support to why the primary EEAASR procurement complies with the statute or would be feasible to implement. (Ameren Response at 5)

Ameren states that when addressing the "Product Definition" section of the Plan, CUB only provides policy statements in support of including only energy efficiency programs in any EEAASR procurement event, as opposed to behind-the-meter generation. Ameren claims the PUA only authorizes the IPA to procure "demand response products" and "standard wholesale products," not "energy efficiency as a supply resource," regardless of what that would comprise. Ameren asserts this position is consistent with the Commission's prior findings on the issue when approving the 2011 IPA Procurement Plan. Ameren contends CUB's comments provide no reason to find otherwise. (Ameren Response at 5-6)

Ameren says CUB's general support does not allay its concerns with having yet another planning, implementation and verification framework subject to the rules of supply in addition to one subject to the current rules of demand side management. Ameren also says CUB's comments do not address Staff's concern that applying the existing savings evaluation, measurement and verification framework currently used for Section 8-103 of the PUA energy efficiency programs would not be feasible given the current purpose (i.e., to determine net savings, not actual energy reduction) and timing of the reports. (Ameren Response at 6)

According to Ameren, CUB summarily states that approving the primary proposal for EEAASR procurement would be "an important step towards establishing a viable energy efficiency market in Illinois" and would serve as "an opportunity for the IPA to incorporate more clean energy into its portfolio in preparation for the carbon intensity reduction requirements of the forthcoming Clean Power Plan proposal from the U.S. Environmental Protection Agency." Ameren claims CUB provides no support or explanation as to how this is so and, in any event, these statements are beside the point. In Ameren's view, the relevant inquiry is not whether procurement events further energy efficiency markets or prepare for a future Clean Power Plan. Rather, it is whether the Plan procures power that "ensures adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." Ameren insists there has been no showing that EEAASR meets these requirements. (Ameren Response at 6-7)

Staff states that the Commission should reject the primary proposal and instead "generally approve the IPA's alternative proposal" for EEAASR. Ameren does not agree. Ameren asserts that the alternative EEAASR procurement proposal suffers from many of the same flaws as the primary proposal (including how verification of supply savings could be timely accomplished), and raises additional issues left unresolved by the Plan (including what peak periods would be targeted and which "rules" for credit requirements and non-delivery penalties would apply) to the EEAASR bidders. Ameren maintains such critical issues must be vetted and resolved prior to approval of any EEAASR procurement and not after. (Ameren Response at 7)

While CUB, ELPC, the AG, the IPA, and Comverge have all weighed in supporting EEAASR procurement, Ameren says each relies on various opinions as to why EEAASR procurement "should" be adopted as a policy matter, even though the AG acknowledges that there are significant issues that still need resolving. Ameren claims opinions are not evidence, and these parties gloss over the critical, threshold question of whether EEAASR "can" be approved under the law or "can" even be implemented in practice. Ameren claims when the Commission considers the operative law and relevant facts, it becomes clear that EEAASR procurement should not be included in the Plan in any form. (Ameren Reply at 15)

According to Ameren, EEAASR procurement is not authorized under Section 16-111.5, as neither the PUA nor the IPA Act refers to a supply product called energy efficiency as a supply resource. Ameren says the Commission recognized as much when rejecting the IPA's last attempt at EEAASR procurement in the 2011 Plan. (Ameren Reply at 15-16, citing Docket No. 10-0563, Order at 43)

The IPA argues that it has addressed the Commission's concerns by specifying quantity and term of the energy efficiency to be procured and by explicitly stating that existing Section 8-103 programs would be presumed ineligible for participation for procurement. Ameren believes the IPA's self-imposed limitations are not enough. Ameren says the Commission specifically found that, even if the quantity and term were

specified, it is difficult to see how EEAASR can be considered a standard wholesale product as required by 16-111.5(b)(3)(iv) of the PUA. (Ameren Reply at 16)

The IPA further argues in favor of EEAASR procurement by stating energy efficiency is being procured "in a number of venues…[and with] the rollout of 'smart meters' across ComEd and Ameren [Illinois'] service territory, the IPA believes the market for demand-side products will continue to grow and evolve." Ameren says these arguments are similar to CUB's unsupported belief that "energy efficiency can easily be measured through advanced metering infrastructure." Ameren states that both the IPA and CUB would like the Commission to agree with their beliefs and then find that EEAASR fits within the definition of a "standard wholesale product." Ameren argues that procurement under Section 16-111.5 cannot be approved on a mere belief that a product falls under the purview of the PUA or; approval must be done based on evidence, analysis and only if "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." (Ameren Reply at 16)

The IPA asserts that nothing in Section 16-111.5 or Section 16-111.5B precludes procurement of EEAASR, and so the Commission is unrestrained from approving it. Ameren asserts the plain language of the PUA belies IPA's position. Section 16-111.5B makes clear what products can be procured and a supply product called "energy efficiency as a supply resource" is not among them. Ameren asserts that Section 16-111.5B, which is titled "provisions relating to energy efficiency procurement" does not authorize energy efficiency as a supply resource but rather sets forth requirements for energy efficiency procurement that the utilities (consistent with Section 8-103), IPA and the Commission must follow when approving the Plan under Section 16-111.5. (Ameren Reply at 17)

Ameren insists the IPA, the Commission and the utilities are each limited by these provisions of the PUA when it comes to the "procurement of energy efficiency" and the plain language of those Sections set the provisions of Section 16-111.5B do not allow procurement of EEAASR. (Ameren Reply at 18)

In Ameren's view, CUB's, ELPC's and the AG's policy-based arguments for finding that EEAASR meets the definition of "standard wholesale product" equally fail. Ameren claims CUB effectively ignores Illinois law and looks to the PJM and MISO capacity markets, which provide for energy efficiency. Ameren asserts Illinois law does not take its definition of "standard wholesale product" from PJM, or MISO and the PUA precludes EEAASR procurement. The AG raises certain questions regarding procurement of "negawatts" but then acknowledges that those questions preclude approval of EEAASR procurement in this docket because there are "very significant and potentially difficult issues to resolve, and mechanisms to be created, to make the IPA electricity procurement of 'negawatts' efficient and effective." Ameren contends no party has provided the Commission with any specific evidence or analysis that would allow a conclusion that EEAASR procurement, should it be deemed a "standard

wholesale product," would discover cost-effective resources not previously available under traditional energy efficiency frameworks. Ameren insists there has been no showing as to why stakeholders, including utilities, should undertake the additional time and expense of developing, planning and implementing a new procurement event, nearly all of which would be passed on to consumers without any showing of additional benefits to them by doing so. (Ameren Reply at 18-19)

Ameren asserts that under the PUA, Section 16-111.5B procurement may only be procured from "eligible retail customers." Because an EEAASR procurement event cannot take place under Section 16-111.5, Ameren says the IPA's intent to procure from a wider base would run afoul of the PUA's requirements. Ameren says the AG acknowledges that there is no statutory authority for an EEAASR procurement from any Illinois electricity customer, rather than from only "eligible retail customers," but argues for one anyway on policy grounds, claiming that "under a broader 21st century view of [demand side resources], that permits distributed generation and traditional supply to compete on an equal footing outside of the Section 111.5B procurement mechanism," "where a resource is sited should not matter, so long as the negawatts are somehow made available to the electric system." Ameren claims, the AG then concedes that there is not a "mechanism to overcome [the legal restrictions of the PUA and]…the IPA proposal is not yet fully fleshed out and articulated in sufficient detail to know exactly how it might intend EEAASR to work." Ameren argues that as it remains unclear from whom the EEAASR would be procured, the Commission could remove EEAASR from the Plan on this basis, as well. (Ameren Reply at 19)

Ameren claims its practical concerns have been largely left unrebutted. Ameren claims they have sweeping implications for a range of Ameren's planning and contracting responsibilities on the supply side, as well as implementation considerations of existing energy efficiency programs in light of the unknown impact that any EEAASR procurement would have on achieved savings (e.g., customers may only choose to participate in either the EEAASR procurement or the Section 8-103 programs). Ameren asserts that also left out of the policy rhetoric in favor of approval is any discussion of how EEAASR would overlap with existing programs (even if the programs are different) in terms and how they would be timely procured, implemented, evaluated, measured or verified in any meaningful way. Ameren complains that no party has provided the Commission any counter-analysis that could overcome these concerns and provide a basis for approval. Ameren says even in the rush to get the concept approved, both the IPA and CUB acknowledge the significant issues that require resolution before a procurement event can take place. According to Ameren, the parties supporting EEAASR ask the Commission to approve EEAASR procurement now and leave it to the parties to figure out how it works later. Ameren asserts that is neither allowed under the PUA (which requires consideration of factors before approval) nor a workable approach in practice, particularly because it is doubtful that some of these issues can be resolved sufficiently to allow for EEAASR procurement, contracting, implementation, evaluation, measurement or verification to take place (Ameren Reply at 20-21)

Staff proposes its own alternative that would tweak the existing Section 16-111.5B RFP process, but Ameren believes would still leave many questions unanswered. ComEd agrees with Ameren that no EEAASR procurement should be approved in the Plan, but is open to spring workshops to discuss the various concerns raised in this docket. Ameren continues to oppose the inclusion of the alternative EEAASR procurement proposal, but notes that it would participate in any Commission-ordered workshops on the exploration of alternative proposals for future dockets. At this time Ameren does not believe those workshops should be ordered as there has been no showing by any party justifying the need to spend the considerable time and resources it will take to address the many, significant outstanding issues with EEAASR procurement. (Ameren Reply at 21-22)

Staff, and now the IPA, have expressed support for modifying the Section 16-111.5B RFP process to specifically seek out targeted energy efficiency programs that could identify and demonstrate reductions during peak periods. Responding to the concerns stated by Ameren and others, Ameren says the IPA appears to have changed its alternative proposal so that no additional, separate RFP process would be needed; no "additional" financial incentives should be employed; that the rules governing incremental energy efficiency under Section 16-111.5B would apply to the alternative proposal; and the summer "super-peak" blocks identified in its proposal would be the peaks to be pursued. The IPA's current position appears to Ameren to be similar to what Staff suggested, in that it essentially requires only an advertisement in the utilities' RFPs that they (1) will pay close attention to when third party vendors' programs are expected to produce energy savings; (2) will take into account intra-day and intra-year differences in expected energy prices when valuing program-induced energy savings; and (3) will take into account the relative reliability with which programs produce energy savings during specific time periods. (Ameren Reply at 22)

Ameren says if its understanding is correct, then both Staff's and the IPA's "alternative proposal" no longer proposes the procurement of energy efficiency as a supply resource. Instead, the IPA's alternative would merely promote the targeting of certain peak period energy savings through traditional energy efficiency channels pursuant to Section 16-111.5B. On that understanding, Ameren would be open to exploring the idea of modifying its RFPs for future Plans to target certain peak period savings, either through the SAG or in connection with a workshop process. Ameren suggests any resolved issues could be then be a part of a future proposal by the IPA in a future Plan. (Ameren Reply at 22-23)

Ameren states that the IPA appears to assert that the meaning of the statutory term "standard wholesale product" changes over time, despite no statutory basis to support its arguments. Ameren believes the language of the PUA controls the analysis and nowhere does Section 16-111.5 allow for the procurement of EEAASR. (AIC RBOE at 6)

Ameren says the IPA has proposed an exception that would substantially alter the meaning of the Proposed Order concerning the alternative proposal. The IPA seeks

to add language stating that the proposal is hereby adopted to inform the development and evaluation of the RFPs for programs submitted for consideration in the IPA's 2016 Procurement Plan. In Ameren's view, the addition is inconsistent with the present language of the Proposed Order, which directs the parties to commence workshops for the purpose of, among other things, deciding whether an additional RFP for energy efficiency programs will even be necessary before the Commission decides whether to adopt the IPA's alternative proposal. Ameren believes the Commission should not adopt this change suggested by the IPA, as it would result in the Commission endorsing a proposal without any concrete resolution of the many material issues that have been raised by the parties in this docket. (AIC RBOE at 7-8)

4. CUB's Position

CUB reports that the IPA has proposed the procurement of EEAASR. CUB says that in doing so, the IPA would procure demand-side resources which are less expensive than conventional supply during periods of high-cost electricity or high-load activity. CUB supports the inclusion of EEAASR in the IPA's resource choices for the Plan. CUB believes this is an important step towards establishing a viable energy efficiency market in Illinois, and an opportunity for the IPA to incorporate more clean energy into its portfolio in preparation for the carbon intensity reduction requirements of the forthcoming Clean Power Plan proposal from the U.S. Environmental Protection Agency. (CUB Objections at 3)

According to CUB, procurement of energy efficiency supply in summer super-peak blocks is a superior option to the proposed alternative of modifying the Section 16-111.5B RFP process because the original proposal will provide more support for the nascent Illinois energy efficiency marketplace. CUB agrees with the IPA's view that energy efficiency qualifies as a standard product, and believes the IPA is authorized to include it in its supply portfolio. (CUB Objections at 3-4)

CUB supports the guiding principles the IPA lays out for its proposed EEAASR procurement since those principles will serve to shape peak load by delivering the benefits of energy efficiency at peak times. CUB says the IPA appears to use the terms "customer-side" and "demand-side" interchangeably, referring to resources that are "behind-the-meter." For clarity, CUB suggests that the approved plan use only "demand-side." CUB asserts that to maximize the impact of the procurement, the IPA should ensure that winning bids representing energy efficiency are prioritized, not simply the replacement of utility supplied energy with behind-the-meter generation. For EEAASR to be an effective tool for fostering a robust energy efficiency market in Illinois, CUB claims procurement must prioritize true reductions in energy usage, not just reductions in load. (CUB Objections at 4)

CUB believes procuring energy efficiency in four-hour, afternoon blocks for summer, non-holiday weekdays as outlined in the Plan is an appropriate strategy. CUB says the summer months are when utilities see the largest variation between on- and off-peak load of the year, due in large part to residential and commercial air-conditioning

systems. In CUB's view, this means the summer afternoon hours are a significant driver of price risk for consumers, because it is when demand is most likely to exceed hedged supply amounts. CUB suggests procuring energy efficiency in super-peak blocks will then have the greatest possible benefit for system-wide consumers, because reducing demand in these hours will lessen the amount of energy purchased on the spot-market, which is often more expensive than hedged supply, especially when demand is at its highest. (CUB Objections at 4-5)

CUB supports the three-year contract length in the proposal as three-year contracts provide assurance to participants that they will be able to recover the capital investment required to implement energy efficiency technologies. CUB claims this will increase the likelihood of robust participation in the market. (CUB Objections at 5)

CUB supports using 100 kW block sizes for the procurement event as CUB believes 100 kW is small enough in size to allow small programs to self-organize into procurement blocks. CUB claims this will enable broad participation in the auction, which will help to foster the energy efficiency market. (CUB Objections at 5)

CUB believes this timeline is appropriate in that it provides time for potential participants to organize into bid groups, and for the IPA to further refine the procurement proposal. CUB says this timeline will also allow for the results of the auction to inform the IPA's regular procurement process. (CUB Objections at 5)

CUB says it appreciates the increased complexity of a winter energy efficiency auction, resulting from less predictable load-profiles. With this complexity in mind, CUB believes a summer-only approach for the first EEAASR procurement is reasonable. (CUB Objections at 5-6)

CUB believes the proposed energy efficiency procurement is an important step for fostering the energy efficiency market in Illinois, presents a timely opportunity to reduce Illinois' carbon intensity in advance of the EPA's forthcoming Clean Power Plan, and will yield valuable benefits for Illinois consumers in terms of price stability by avoiding potentially costly spot-market energy purchases. That said, in the event the market fails to self-organize prior to the procurement or other significant barriers arise or persist, CUB says postponement may be necessary. CUB supports the requirement in the submitted proposal that in the event cancellation or postponement is necessary, the IPA would need to request cancellation through a filing with the Commission. (CUB Objections at 6)

CUB reports that the IPA proposes to use the ISO-New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources as the starting point to developing a qualification process for EEAASR resources. CUB agrees that a "rigorous" qualification process is essential, and agrees that the manual provides an appropriate and comprehensive methodology for qualification of energy efficiency resources, and should be adopted for the procurement. (CUB Objections at 6)

CUB notes the IPA states it seeks to avoid overlap with energy savings delivered under the EEAASR procurement and those delivered under the Energy Efficiency Portfolio Savings ("EEPS") programs and the IPA's own purchase of incremental energy efficiency from the EEPS programs. CUB says the EEAASR represents an important avenue for the development of new energy efficiency resources. CUB states that if there are existing energy efficiency programs that could be incentivized to increase their supply of energy efficiency, or if there are existing programs that have benefits not yet fully compensated through existing funding sources, those programs should be able to participate in the procurement as well. CUB says incremental increases in energy efficiency from these programs could be mathematically "backed out" of their participation in Section 8-103 or Section 15-111.5B programs. CUB suggests it might be possible to take the annual savings generated by an EEPS measure and calculate the avoided energy usage at the peak times of EEAASR procurement. CUB says the value of the savings in those particular hours could be separated from the other annual savings both in terms of cost of the energy efficiency kWh at a particular time, the cost of a measure annually and the savings generated both annually and at the EEAASR times. (CUB Objections at 6-7)

CUB believes the purpose of this procurement should be a reduction in total energy usage versus a pre-existing baseline, not just a reduction in consumer load. To CUB, this means participating programs should be actual energy efficiency resources, not the replacement of utility load with behind-the-meter generation, with the possible exception of combined heat and power systems. Were customers allowed to bid in their standby generation as energy efficiency, CUB says this would simply represent a back-door method for third parties to compete with standard generation resources, which is not the intent of the procurement. CUB states given the first principle of the proposed procurement, that it be "structured to provide lower expected total customer costs than a comparable supply-side procurement," it is not likely that standby generation would be able to compete on a cost basis with actual energy efficiency, and would not be able to submit a successful bid anyway. With regard to the difference between energy efficiency and demand response resources, CUB believes both technologies should be eligible to participate on equal footing in the procurement, to ensure broad participation and create the biggest impact for the energy efficiency market. (CUB Objections at 7-8)

CUB agrees with the IPA that an EEAASR procurement should feature no more default or non-delivery risk than a standard energy supply procurement. At the same time, CUB believes that there must be penalties and structures that ensure against non-delivery. CUB believes the IPA should hold bidders strictly accountable for successfully bid energy efficiency resources, using industry best practices. (CUB Objections at 8)

CUB agrees with the IPA that the existing verification practices in the Illinois Technical Reference Manual for Section 8-103 programs is an appropriate source for evaluating energy efficiency resources in this procurement. (CUB Objections at 8)

In the event that the Commission decides not to approve the IPA's EEAASR proposal, the IPA includes an alternative in its Plan. Its proposal is a modification of the Section 16-111.5B process to "specifically seek out programs that would reduce demand during peak hours and provide additional incentives for those programs while remaining cost effective." CUB believes that while this alternative plan would accomplish some of the load reduction goals of the original EEAASR proposal, likely resulting in system wide consumer savings through avoided spot-market energy purchases, it would not go as far as the original proposal in fostering the Illinois energy efficiency market. CUB urges the Commission to approve the IPA's original EEAASR procurement proposal, as it will achieve the greatest combined impact for system-wide electric consumers as well as energy efficiency market participants. (CUB Objections at 8-9)

CUB believes the IPA has a difficult mission to fulfill. Each year, CUB says the IPA must structure a procurement plan that will ensure "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time." In CUB's view, 2015 presents an opportunity for the IPA to further incorporate new technologies and business models into its procurement process. CUB and EDF recommend the Commission adopt the primary EEAASR procurement proposal detailed in the IPA Plan. CUB and EDF also support adoption of the IPA's alternative EEAASR proposal with modifications. (CUB Response at 1)

CUB reports that in the 2015 IPA Draft Procurement Plan, the IPA proposed a separate 2015 procurement for energy efficiency resources in prescheduled, summer 2016 super-peak blocks. In the IPA Plan, CUB says the IPA included an alternative proposal, which would modify the Section 16-111.5B third-party RFP process to "specifically seek out programs that would reduce demand during peak hours," in order to achieve some of the benefits of an EEAASR procurement while avoiding some of the objections raised by parties in comments on the Draft Plan. (CUB Response at 2)

CUB indicates that several parties recommend the Commission reject the primary EEAASR proposal, on the grounds that it is not authorized as it would fall outside of the scope of Section 16-111.5B of the PUA. CUB says the primary basis of this objection is the assertion that energy efficiency does not qualify as either a standard wholesale product or a demand response product. CUB adds that parties also objected to the concept of allowing competitive class customers to participate in the procurement, as load reductions by competitive class customers would not have any impact on the load requirements of eligible retail customers. (CUB Response at 2)

CUB believes the primary EEAASR procurement proposal is authorized by statute, and merits inclusion in the IPA Plan. CUB agrees with the IPA that energy efficiency should be considered a "standard wholesale product." CUB states that energy efficiency resources are eligible to participate as wholesale products in both PJM and MISO capacity markets. CUB says both PJM and ISO-New England have established protocols for verifying performance of energy efficiency and demand response resources. CUB states that PJM's Reliability Pricing Model also has an

established auction process for energy efficiency resources, allowing for bids to be differentiated on price. CUB contends energy efficiency can be easily measured through advanced metering infrastructure and is functionally equivalent to traditional generation. CUB claims that given that 1) energy efficiency contracts are already traded in liquid markets, 2) energy efficiency resources can be differentiated by price, and 3) energy efficiency performance can be measured through existing infrastructure and methodology, it ought to be considered a "standard wholesale product," and the IPA is within its authority to procure it as a supply resource outside of the Section 16-111.5B incremental energy efficiency framework. (CUB Response at 3)

CUB does not believe measurement and verification need present an insurmountably costly or complex obstacle; as CUB asserts established industry best practices for measurement and verification of load reductions exist that could be applied to resources procured under this proposal, and advanced metering infrastructure would allow for instant measurement of energy usage versus a participant's baseline. CUB supports the inclusion of the primary EEAASR procurement proposal, with the modification that bids not be accepted from competitive class customers. (CUB Response at 4)

Should the Commission choose not to approve the primary EEAASR proposal in this year's procurement plan, CUB supports inclusion of the IPA's alternative proposal as an interim step forward, with some suggested modifications. To improve the transparency of the Section 16-111.5B procurement, CUB suggests the RFP process should be conducted through the IPA, rather than the individual utilities. CUB claims this will ensure even implementation of the procurement between the two utilities' delivery areas, and allow for easier third-party review of the decision criteria. (CUB Response at 4)

As part of this IPA-led RFP process, CUB suggests the IPA should conduct and publish a "maximum potential" study of peak hour-specific energy efficiency programs, of the same sort required for incremental energy efficiency programs already participating under Section 16-111.5B. CUB claims that by examining whether all cost effective peak reducing energy efficiency is being purchased, this potential study will ensure the IPA is maximizing the potential benefits of the underutilized energy efficiency market in Illinois. In addition to the maximum potential study, CUB suggests the IPA should work with the Commission to update the TRC test to reflect time-specific avoided energy costs, so that it better reflects the benefits of load reductions during peak time. (CUB Response at 4)

Staff also suggests that energy reductions during specific blocks of time would likely be more expensive than over a broad timeframe, but offers no evidence for this assertion. CUB says high energy costs during peak periods arise due to constraints in energy supply, which are not likely to correlate with periods of higher opportunity cost for energy efficiency providers; indeed, this time period arbitrage is a primary driver of the energy efficiency opportunity. CUB asserts a TRC test that does not account for time-specific energy costs would systematically undervalue peak-specific energy

efficiency programs. CUB claims it is not necessary for the concept of peak time energy efficiency as a category to pass the TRC, rather, CUB says the point of a TRC is for individual peak time reduction offering to be evaluated on their own relative merits. CUB believes it is important that this update of the RFP process and TRC occur under the auspices of the IPA and Commission, in collaboration with the Illinois Energy Efficiency SAG, with the goal of reaching a prompt resolution. (CUB Response at 5)

CUB agrees with Staff's assertion that it is unnecessary for the IPA Plan to set forth the incentive level for energy efficiency participants; rather, the incentive level, as well as costs of procurement administration, are reviewed as part of the TRC calculation. If the alternative plan is adopted, these costs will be evaluated alongside any other type of energy efficiency program. CUB also supports the three-year time frame proposed by the IPA for programs, as CUB claims this would provide the necessary incentive for providers to make efficiency investments, and match the IPA's normal procurement timeline. (CUB Response at 5)

CUB/EDF say the primary objection seems to be that some parties believe that energy efficiency could not be considered a standard wholesale product, which the IPA is required to purchase under the PUA. These parties appear to base this conclusion on two phrases in the Public Utilities Act: "demand response products" and "standard wholesale products." CUB agrees that these phrases refer to two specific products in the PUA. CUB does not agree that energy efficiency cannot be considered a standard wholesale product. CUB/EDF argue that energy efficiency, just like demand response and traditional generation supply, is procured through wholesale markets based in volumes which differ based on a market clearing price. If the IPA has the authority to procure standard wholesale products, then CUB/EDF believe the IPA has the authority to procure standard wholesale products which include energy efficiency and demand resources that are traded and purchased at wholesale markets. (CUB/EDF Reply at 4)

CUB and EDF agree with the AG and the IPA that energy efficiency should be considered a "standard wholesale product." CUB/EDF agree with the AG that from the perspective of the electric grid, there is no tangible difference between watt-hours and "negawatt-hours", and that they should be allowed to compete on equal footing in energy procurement events. CUB/EDF agree with the IPA that "energy efficiency products are currently being procured in a number of venues, including PJM and ISO-NE." CUB/EDF argues that since there is no language in the IPA Act, PUA, or Energy Infrastructure Modernization Act that states energy efficiency is not a "standard wholesale product", the IPA is within its authority to include it as a supply resource in its energy portfolio. (CUB/EDF Reply at 4-5)

CUB/EDF say the language that is present in the IPA Act directs the Commission to approve a procurement plan if the Commission determines that the plan will meet the IPA's objectives in ensuring adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. CUB/EDF agree with the AG that if demand side resources, such as those that would provide the EEAASR product, are both reliable and available

at a lower cost than traditional supply options, the Commission must conclude it is in the public interest to procure them. CUB/EDF assert efficiency continues to provide the least-cost energy resource option even as the amount of energy efficiency being captured has risen. CUB and EDF also agree with the AG that as a "standard wholesale product," EEAASR can be procured from all available bidders, not just eligible retail customers. (CUB/EDF Reply at 5)

CUB/EDF contend any facility or aggregation of retail customers should be allowed to bid negawatts into the procurement, so long as appropriate measurement and verification accounting can be developed. Ameren concludes that Staff is correct that the existing evaluation, measurement and verification procedures used to quantify net savings for the existing utility energy efficiency programs mean that energy reductions at peak times would be equally laborious. CUB and EDF agree that the existing EMV procedures for the utility programs do not use actual billing data but rather rely on a mix of surveys, assumed savings and adjustments for the existence of other utility programs. CUB/EDF say the methodologies for calculating these savings is annually reviewed in Commission proceedings and captured in a Technical Reference Manual updated and revised by an entire subcommittee of the SAG that works with the electric utilities to advise them on the implementation of their efficiency programs. CUB and EDF agree that this process is not aimed at capturing real energy savings or reductions in energy usage. CUB/EDF also assert that this process does not incorporate or address the real-time data which will be available from the widespread deployment of advanced metering infrastructure ("AMI") or the existing procedures used by wholesale markets such as PJM and ISO-New England which could be adopted for use here. CUB and EDF would support using procedures which incorporate those best practices and build upon the billion dollar infrastructure investment being made by ComEd and Ameren rather than the calculations of savings based on methodologies which do not look at actual energy data. (CUB/EDF Reply at 6)

ComEd and Ameren both ultimately conclude that there remain too many "open issues regarding the EEAASR proposal" for it to be adopted at this time. CUB/EDF claim the IPA has already provided a path forward for the resolution of any open issues. They say the EEAASR proposal does include an inclusive stakeholder process for resolving open issues, and ample time before the procurement would take place. CUB and EDF agree with the IPA and the AG that it is important for the Commission to provide support for this proposal even if it concludes that there are issues remaining which must be addressed before approval can be given. CUB/EDF believe the Commission should approve the primary proposal for a late-2015 procurement of energy efficiency as a supply resource, as described in the IPA Plan, and "emphatically assert that finding appropriate mechanisms and market strategies that can allow [demand side resources] to compete on an equal footing with traditional supply is not only desirable but fundamentally an obligation of the IPA in its charge to provide customers with the lowest cost, reliable electric resources." (CUB/EDF Reply at 6-7)

Should the Commission conclude that even further discussion of EEAASR is not appropriate for some reason at this time, CUB and EDF support the IPA's alternative proposal as described in the Plan and the IPA Response. (CUB/EDF Reply at 7)

5. The IPA's Position

The IPA reports ComEd, Staff, and Ameren each object to the IPA's proposed procurement of EEAASR. Through this proposal, the IPA is proposing to procure energy efficiency as a "standard wholesale product" pursuant to its authority under Section 16-111.5 of the PUA. (IPA Response at 17)

The IPA indicates ComEd and Staff object that energy efficiency cannot be considered a "standard wholesale product" as required by the PUA. The IPA disagrees. The IPA believes that whether "energy efficiency" may be proposed under its Section 16-111.5(b) authority turns on the degree to which its proposal constitutes the procurement of a "standard wholesale product." The IPA states that in Docket No. 10-0563, the Commission rightfully rejected the IPA's Energy Efficiency as a Resource ("EEAR") proposal in its 2011 Plan, noting among its concerns that the proposal did not specify the quantity and term to be proposed, how demand reductions would be balanced with identified load requirements, how energy efficiency procured would be balanced with projected load requirements, and whether energy efficiency may be double counted with programs conducted pursuant to Section 8-103 of the PUA. (IPA Response at 17-18)

With this guidance in mind, and through additional guidance gleaned from stakeholder feedback on the proposal in the 2014 Plan, a 2014 workshop, follow-up questions from that workshop, and feedback received on the proposal in its draft 2015 Plan, the IPA says it crafted its EEAASR proposal. The IPA says its proposal calls for the procurement of 100 kW block demand-side products (quantity) at a pre-specified 5 x 4 "super-peak" period in contracts for three years (term); expressly addresses how efficiency procured would impact projected load requirements (and has developed a timeline and process to address this concern); and the IPA wishes to make clear that existing Section 8-103 programs would be presumed as ineligible for participation for this procurement at this time (while recognizing that there may be opportunities to reconcile dual participation through future refinement of this procurement strategy). (IPA Response at 18)

The IPA says that although the Commission in 2010 noted that the PUA contained no "express authorization" for the procurement of energy efficiency as a supply resource, the Commission stated in Docket No. 13-0546 that such express authorization is not required for a product to be considered a "standard wholesale product" under Section 16-111.5(b)(3)(iv). (IPA Response at 18)

The IPA believes the definition of "standard wholesale product" is dynamic, changing with what products are being bought and sold at a given time. Energy efficiency products are currently being procured in a number of venues, including PJM

and ISO-NE. With the rollout of "smart meters" across ComEd and Ameren's service territory, the IPA believes the market for demand-side products will continue to grow and evolve. (IPA Response at 19)

Unable to cite to statutory language in Section 16-111.5(b)(3)(iv) limiting "standard wholesale products" to exclude energy efficiency, the IPA says ComEd and Staff object that Section 16-111.5B of the PUA operates as the exclusive mechanism through which the IPA may propose to procure energy efficiency. The IPA argues nothing in Section 16-111.5B, enacted via the Energy Infrastructure and Modernization Act, states that energy efficiency cannot be considered a "standard wholesale product" procured under Section 16-111.5(b). The IPA also contends nothing in Section 16-111.5(b) was altered by EIMA to expressly exclude the procurement of energy efficiency products. (IPA Response at 19)

The IPA says ComEd stresses that the timeline associated with the Commission's 2010 Order and the 2011 passage of the EIMA supports a reading that Section 16-111.5's authority excludes energy efficiency. According to the IPA, the plain language of Section 16-111.5B demonstrates that its passage was intended to address limitations posed by Section 8-103 of the PUA, not to solve challenges posed by the attempted procurement of energy efficiency under Section 16-111.5(b). The IPA notes Section 8-103 is referenced in seven separate subparts within Section 16-111.5B, while no reference is made to Section 16-111.5(b) or the procurement of standard wholesale products. (IPA Response at 19)

The IPA reports ComEd, Staff, and Ameren also argue that the IPA's proposal must be rejected because the IPA seeks to procure energy efficiency from customers other than "eligible retail customers," claiming that "eligible retail customers" would receive no benefit from demand reductions procured from non-eligible retail customers. The IPA believes this argument should be rejected. (IPA Response at 20)

The IPA contends capacity and supply costs for eligible retail customers are driven by a combination of system load and supply deliverable to a utility's service territory, supply and demand. The IPA states procuring peak demand reductions from any customer within the utility's footprint, reducing demand, reduces the overall capacity obligations and peak energy supply costs for eligible retail customers, regardless of whether that energy efficiency is actually procured from eligible retail customers. To this end, the IPA says it is seeking to procure "super-peak" blocks to shave peak load and reduce eligible retail customer supply costs, providing such customers with concrete benefits. (IPA Response at 20)

The IPA indicates it does recognize a challenge with Section 16-111.5(b)(3)(iv)'s obligation that the IPA's procurement plan be developed to "meet that portion of its load requirements." The IPA's "load requirements" are a function of projected eligible retail customer load; reductions procured from customers who are not eligible retail customers do not directly reduce eligible retail customer load. While the IPA believes its proposal meets this standard by including the procurement of energy efficiency from

eligible retail customers (as its proposed procurement would reduce eligible retail customer load, although not exclusively so), this highlights an important issue for Commission resolution. (IPA Response at 20-21)

The IPA says Ameren, ComEd, and Staff suggest that because the IPA has identified unresolved issues in its EEAASR procurement, it must be rejected. The IPA agrees that significant issues are identified as unresolved, but disagrees that this necessitates the proposal's rejection. The IPA believes its proposed process (the initiation of workshops after the conclusion of this docket; ability to cancel a procurement based on a determination that it may not be "cost-effective") and generous timeline (procurement to take place in late 2015, conducted for the delivery year beginning June 1, 2016) can accommodate the resolution of open issues. If the Commission believes resolution of open issues requires a compliance filing or additional steps, the IPA would be supportive. (IPA Response at 21)

The IPA reports it also includes in its Plan an alternative proposal utilizing changes to the inclusion of third-party energy efficiency programs proposed under Section 16-111.5B of the PUA. ComEd "supports further consideration of this Alternative proposal," Staff "generally supports" the alternative proposal, and Ameren has "additional concerns" with the alternative proposal and believes it should also be rejected, while CUB does not clearly state its support or opposition. While the IPA believes its original EEAASR proposal is authorized and advocates for its adoption, the IPA suggests the Commission may wish to recognize the broader consensus behind the IPA's alternative proposal. (IPA Response at 21-22)

ComEd questions whether the alternative proposal calls for another RFP separate from the RFP already proposed, claiming that it is difficult, if not impossible, to see how a separate RFP process could be conducted. To clarify, the IPA says it does not believe a separate RFP is required. (IPA Response at 22)

ComEd also states that its cost-effectiveness tool – DSMore – already conducts cost-benefit tests using hourly values. It is unclear to the IPA whether this attaches appropriate evaluative weight to peak reduction benefits, as not all benefits may be captured through modeled hourly wholesale energy prices. The IPA believes further examination of the effectiveness of this screening through a workshop process is warranted. (IPA Response at 22)

ComEd, Staff, and Ameren believe that no additional financial incentive is warranted or justified to target programs reducing peak demand. In reviewing Objections, the IPA agrees, as adjustments to the TRC will allow bidders to incorporate any additional incentives into bids with the added confidence that they can do so cost-effectively. (IPA Response at 22)

Ameren believes clarification is required as to which rules govern the IPA's alternative proposal. To clarify, the IPA believes that rules governing incremental energy efficiency under Section 16-111.5B would apply. Ameren also requests

clarification as to what "peak" would be pursued. To the extent clarification is necessary, the IPA believes that the summer "super-peak" blocks identified in its EEAASR proposal is a sufficient starting point and further refinement could be achieved through the IPA and stakeholder input process outlined in Section 16-111.5B(a)(3) of the PUA. (IPA Response at 22-23)

The IPA continues to believe that its primary EEAASR proposal is authorized under Section 16-111.5(b) of the PUA as the procurement of a "standard wholesale product." Likewise, the IPA continues to believe that its alternative EEAASR proposal is a sound, legally supported alternative. In Response, Ameren alleges that the IPA's alternative proposal "suffers from many of the same flaws as the primary proposal," considering various issues unresolved. If there are specific deficiencies which Ameren believes are lacking in this proposal, the IPA says it would be happy to provide further clarification. The IPA states as such issues go largely unidentified in filings, conclusory statements about a proposal that "suffers . . . the same flaws" fail to resolve whatever clarity or additional detail Ameren seeks. (IPA Reply at 10)

While the IPA acknowledges that it has identified primary EEAASR proposal challenges to be resolved collaboratively after this docket, it does not view the alternative proposal as nearly as ambiguous as Ameren claims. The alternative proposal is being brought under Section 16-111.5B of the PUA, and the IPA believes this makes clear that the requirements of Section 16-111.5B apply and hopes any additional open issues have been adequately addressed in its Response. (IPA Reply at 10-11)

CUB proposes that to improve transparency, the IPA's Section 16-111.5B alternative EEAASR proposal RFP process "should be conducted through the IPA, rather than the individual utilities." It is unclear to the IPA what is meant by "through the IPA" in CUB's proposal, but any RFP process conducted under Section 16-111.5B of the PUA must be conducted consistent with the statute. The IPA appreciates the need for increased transparency and a more inclusive Section 16-111.5B process. The IPA says these very concerns informed its "feedback loop" discussion in the 2014 Plan and its proposal for stakeholder input on third-party bid review in the present docket. The IPA states a more comprehensive and collaborative RFP development and review process is crucial to ensuring that Section 16-111.5B programs "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as envisioned by the law. The IPA is supportive of taking a more active role, so long as such a role is consistent with the delegation of authority outlined in the statute. (IPA Reply at 11)

CUB also suggests that the IPA should "conduct and publish a 'maximum potential' study of peak-hour specific energy efficiency programs" as part of an "IPA-led RFP process." The IPA is intrigued with this proposal, but believes it lacks sufficient detail to be fully evaluated. Additionally, it is unclear to the IPA how this study would intersect with the conventional potential studies that the utilities are statutorily required to conduct, and the IPA is concerned that any such study may not be completed in time

for development of the 2016 Plan. The IPA suggests that should the alternative proposal be approved by the Commission, CUB should provide a more detailed proposal to the IPA. (IPA Reply at 11-12)

CUB further proposes that the IPA should work with the Commission to update the TRC test to reflect time-specific energy costs. It is unclear to the IPA what is meant by "work with the ICC" (whether with Staff or the Commission itself, and whether through open collaboration or as part of this or another docketed proceeding), but the IPA supports workshops after the conclusion of this docket, through the Illinois SAG, to work through issues related to how the TRC test could be updated to better account for time-specific energy value (including energy costs). (IPA Reply at 12)

6. The AG's Position

According to the AG, ComEd, Ameren, and Staff expressed significant concerns with the IPA EEAASR proposal, and for the most part encourage the Commission to reject the IPA's proposal. The AG says some indicate some conditional support for the IPA's alternative EEAASR proposal to simply include in the Section 16-111.5B of the PUA procurement mechanism modified approaches to ensure that higher value can be paid for demand-side resources that focus on super peak savings. (AG Response at 7)

The AG claims the IPA's EEAASR proposal is fundamentally an attempt to recognize demand-side resources ("DSR") on an equal footing with supply, and to allow DSR to compete with more traditional supply resources. The AG says that unlike the current Section 16-111.5B procurement mechanism that purchases efficiency explicitly as an offset to forecasted eligible loads, this approach would view DSR as simply another form of electric energy to meet customer energy needs. (AG Response at 7)

The AG says ComEd, Ameren and Staff argue that Section 16-111.5B is the only part of the PUA that can support procurement of energy efficiency or other demand-side resources. The AG states that they argue that because other sections do not specifically declare efficiency as a potential resource, it is therefore precluded to be considered a resource. According to the AG, in essence, they argue that the PUA directs IPA to only procure "standard wholesale products" and they argue that DSR cannot meet this criterion. (AG Response at 8)

The AG encourages the Commission to take a broader, more expansive view of the term "standard wholesale product," and to allow and direct the IPA and stakeholders to further explore how an EEAASR could possibly work within existing legislative constraints. The AG states that the PUA directs the Commission to approve a procurement plan, including the forecast used in the procurement plan, if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account the benefits of price stability. The AG argues that if DSRs are available that are both reliable and lower cost than more traditional supply options, it is in the public interest to procure them, and the IPA should be encouraged to explore ways to

appropriately and equitably do so. The AG says it is part of IPA's obligation to minimize total costs of energy services, and the AG commends the IPA for creatively exploring alternative methods to do this. (AG Response at 8-9)

The AG argues that the IPA is simply purchasing watt-hours for its eligible customers. The AG says DSRs provide "negawatt-hours" that should be viewed as fundamentally no different than watt-hours, and indistinguishable to the overall electric grid. The AG states that at any given hour the electric grid is indifferent whether an additional watt-hour is generated through a traditional supply resource or simply removed from the demand-side load the grid is meeting. In the AG's view, any resource, either supply-side or demand-side, is reduced to the standard commodity of watt-hours. (AG Response at 9)

The AG says nuclear generation is different than coal, or photovoltaics, or wind generation. The AG states that these are all fundamentally different technologies, with different operating parameters and costs, lifetimes, maintenance needs, environmental impacts, etc. The AG says they are all considered "standard wholesale products" because what the IPA is really purchasing is simply watt-hours provided during specific time periods. The AG argues the product is reduced to a "standard product" measured as watts or watt-hours, and they all compete against each other in the procurement process. The AG contends that because the IPA is an aggregator and reseller of energy, any energy product it purchases must be considered a "wholesale product." The AG sees no reason procurement of any resource that meets the IPA energy need by providing watt-hours and/or negawatt hours should not be viewed as the procurement of a "standard wholesale product" so long as the IPA can show it is reasonably reliable and quantifiable. (AG Response at 9-10)

The AG argues that as distributed generation and energy storage on the customer side of the meter, as well as other energy resource opportunities such as efficiency become more prevalent, artificially drawing boundaries based only on the siting and ownership structure of technology becomes more and more problematic and diverges from the public interest. (AG Response at 10)

The AG acknowledges that there are very significant and potentially difficult issues to resolve, and mechanisms to be created, to make the IPA electricity procurement of "negawatts" efficient and effective. The AG agrees that these details have not been fully worked out and articulated sufficiently by the IPA to unconditionally approve the EEAASR for 2016 procurement. The AG encourages the Commission not to reject out of hand any possibility for an efficient and effective EEAASR to be pursued in the future if these issues can be resolved satisfactorily. The AG believes the Commission should explicitly support the EEAASR concept, and emphatically assert that finding appropriate mechanisms and market strategies that can allow DSRs to compete on an equal footing with traditional supply is not only desirable, but fundamentally an obligation of the IPA in its charge to provide customers with the lowest cost, reliable electric resources. Rather than simply reject the EEAASR proposal, the AG encourages the Commission to direct the IPA to further explore and develop an

EEAASR, in collaboration with the SAG and Staff, to see if an efficient and effective mechanism can be designed. (AG Response at 10)

According to the AG, Ameren rightly indicates that a stakeholder workshop process alone should not be sufficient for approval of an EEAASR, given how many outstanding issues are yet to be resolved. The AG agrees that any final EEAASR proposal to be developed collaboratively by the IPA and stakeholders should still be subject to future Commission approval when and if it is developed. The AG believes it is important that the Commission provide support for the concept and direct the parties to creatively address it rather than simply reject it because it is not fully and completely designed. The AG acknowledges that it seems likely this process might take longer than the IPA initially envisioned, and that a procurement solicitation for 2016 may not be possible. The AG cautions against precluding that possibility. (AG Response at 11)

The AG says a second major criticism of the EEAASR proposal is that the IPA has proposed that DSRs could come from any Illinois electricity customer, regardless of whether they are "eligible customers." The AG claims this is fundamentally consistent with the EEAASR concept of viewing negawatts as a supply resource. The AG says it acknowledges that the legal boundaries of exactly where a resource is sited should not matter, so long as the negawatts are somehow made available to the electric system. The AG says ComEd, Ameren, and Staff argue this is explicitly precluded by the Section 16-111.5B of the PUA, which limits efficiency procurement (viewed and defined in Section 16-111.5B as a reduction in load rather than a supply resource) to coming only from eligible customers. The AG argues that under a broader 21st century view of DSRs, that permits distributed generation and traditional supply to compete on an equal footing outside of the Section 16-111.5B procurement mechanism, this distinction makes no sense. The AG contends the IPA is not limited to procuring supply from only eligible customers. The AG claims that by definition, it is hard to imagine that any eligible customers could or would bid to provide supply to IPA. The AG says the independent power producers offering this resource are not eligible customers. The AG claims there should similarly be no restrictions on the facilities that can provide negawatts to the IPA, so long as that resource can be adequately monitored and verified, and in some fashion made available for the benefit of eligible customers. (AG Response at 11-12)

The AG suggests considering a battery installation at a non-eligible industrial facility, where a super peak load shaving resource is built and committed to being dispatched to reduce the IPA's super peak procurement needs. If this can effectively compete with traditional supply, the AG claims the IPA and the Commission should be indifferent whether that battery bank was owned and sited at a non-eligible customer's facility or owned and sited at an eligible customer's facility. In the AG's view, efficiency should be no different than storage or customer-sited generation, so long as the appropriate evaluation, measurement and verification ("EM&V"), accounting and regulatory mechanisms can be worked out to adequately measure the resource and ensure it benefits the eligible customers with a lower cost and reliable resource. The AG says while it is somewhat more challenging with efficiency than generation or

storage to develop this mechanism, it is not impossible. According to the AG, the well-established EM&V industry has developed methods to measure overall aggregate diversified impacts of DSRs at a sufficient level to support this. (AG Response at 12)

The AG says ComEd, Ameren, and Staff argue that if a non-eligible customer saves energy, there is no mechanism for eligible customers to benefit from this; rather, the IPA would still have to procure the exact same amount of supply resource for the eligible customers, and the savings would simply accrue to the non-eligible customer. The AG agrees that currently a mechanism to overcome this issue is not in place. The AG also agrees that the IPA proposal is not yet fully fleshed out and articulated in sufficient detail to know exactly how it might intend EEAASR to work. It seems plausible to the AG that the IPA and stakeholders could develop a mechanism to do this. The AG argues that if the DSR is a lower cost and reliable resource, than society will benefit from its procurement. The AG contends so long as society as a whole can produce net benefits from the DSR, a mechanism to keep track of the resources and redistribute some or all of these net benefits in an equitable fashion could be implemented. (AG Response at 12-13)

The AG is not proposing a specific mechanism, and it acknowledges this is a potentially difficult and challenging task. The AG also maintains that it is critical to further explore and develop appropriate mechanisms to resolve these issues if the IPA and the Commission are to ensure that the public interest is served and that least cost resources are procured. In the AG's view, to not proactively accept this challenge of developing new and innovative mechanisms to allow DSR to compete on an equal footing with supply will preclude the cost-effective development of DSRs that can provide substantial economic, environmental and reliability benefits to the people of the State of Illinois. The AG encourages the Commission to both acknowledge this new energy system reality, the continual and appropriate blurring of lines around customer versus utility ownership and siting, and to direct the IPA and stakeholders to work on development of a mechanism that can allow all appropriate and cost-effective resources to compete in Illinois. (AG Response at 13)

ComEd argues that the PUA requires that any DSRs pass the Total Resource Cost Test, and because the IPA has not explicitly required that, the EEAASR Proposal should be rejected. The AG thinks it is highly likely that any DSRs that can compete economically would pass the TRC test, since by definition they will be lower cost than the alternative. The AG does not see this as a critical obstacle to pursuing an EEAASR. (AG Response at 13-14)

ComEd argues that because Section 16-111.5B efficiency resources are screened for cost-effectiveness under the TRC Test using time differentiated avoided costs in DSMore that all DSRs are already valued appropriately, and there is no need for any additional mechanisms to focus on super peak resources. The AG is unsure exactly how ComEd develops and uses its avoided costs. The AG argues while DSMore can support hourly analysis of avoided costs, its understanding is that efficiency resources in Illinois have traditionally been screened with a limited number of

broad avoided cost periods, and do not fully reflect hourly simulations. The AG contends that even if this is the case, the current Section 16-111.5B procurement mechanism RFP process does not fully support and encourage innovative proposals that focus solely on super peak, and bidders have significant barriers to understanding whether a potential DSR bid focusing only on super peak savings would pass screening, or how to properly value and evaluate their concept to determine if it can be competitive. The AG also claims that establishing an EEAASR mechanism could open the door for a wider range of innovative proposals that bundle and aggregate combinations of supply-side and demand-side resources into a single grouping of cost-effective resources that would not be feasible under the current Section 16-111.5B RFP procurement process. The AG can imagine an innovative combination of solar, efficiency, gas generation, and energy storage sited in a distributed fashion all combining to provide the IPA with a diversified, low cost, reliable resource at a competitive price. (AG Response at 14)

7. ELPC's Position

ELPC agrees with CUB that EEAASR procurement should be included in the Plan, as procuring additional EE targeted at super-peak blocks could prove to be a cost-effective and cleaner option than procuring peak generation for Illinois and could help reduce the carbon intensity of the electricity in Illinois. Further, ELPC agrees with CUB's suggestion that for clarity the Plan use the phrase "demand-side" rather than "customer-side," to clarify that the EEAASR procurement is targeting energy efficiency that actually reduces energy usage. (ELPC Response at 3-4)

ELPC agrees with CUB that IPA procurement of EEAASR in summer super-peak blocks is superior to the alternative of modifying the 16-111.5B process. ELPC believes that the IPA will have better success at procuring summer super-peak EEAASR than a utility RFP because the IPA will be more transparent in its procurement process, the IPA will be more open to stakeholder feedback, and the IPA has already held workshops on the topic and thus is likely better prepared for such a procurement than the utilities. (ELPC Response at 4)

ELPC agrees with CUB's support for the Plan's proposals to procure EEAASR in four-hour blocks on summer non-holiday weekdays, using three-year contracts. ELPC agrees that reducing energy usage through energy efficiency on the customer side of the meter during "super peak" hours in the summer can be a cost-effective strategy to reduce reliance on conventional supply, reduce costs for ratepayers, and relieve stress on the grid. ELPC believes three years is long enough to attract suppliers who want longer-term stability to recover startup costs and administrative expenses, while it is also short enough to allow products to adapt to changes in the market that may occur over three years. (ELPC Response at 4)

8. Comverge's Position

Comverge notes Staff has proposed that the EEAASR Alternative proposed by IPA be adopted with one modification to the third bullet point on page 72 of the 2015 Procurement Plan. Comverge urges the Commission to approve the inclusion of the EEAASR Alternative, as modified by Commission Staff, in the IPA's 2015 Procurement Plan. (Comverge Response at 2-3)

In ComEd's Objections, ComEd stated that the EEAASR Alternative "warrants serious discussion" and should be included in the 2015 Procurement Plan as modified by ComEd. Comverge states that under ComEd's proposed modifications, the EEAASR Alternative would be explored by the parties during a workshop process without any Commission mandate that ComEd and Ameren modify their third party energy efficiency RFP process to specifically seek out programs that would reduce demand during peak hours. Comverge does not support ComEd's approach because it does not mandate that the utilities actually implement any modification to their third party energy efficiency RFP to solicit programs that would reduce demand during peak hours, as the IPA has proposed in its EEAASR Alternative. Since the approach proposed by ComEd would not assure that the goal of IPA's EEAASR Alternative peak demand reductions would actually be achieved even if the peak demand reductions are cost-effective, Comverge urges the Commission to reject ComEd's proposed modifications to the EEAASR Alternative. (Comverge Response at 3)

ComEd complains that the IPA has provided no analysis to the Commission to support EEAASR procurement as is required by Section 16-111.5B of the PUA. Comverge says what is left unspoken by ComEd is that the analysis of EEAASR procurement could not be provided by the IPA because ComEd did not provide an analysis of peak demand reduction programs in its assessment of energy efficiency programs required to be provided by the utilities to the IPA under Section 16-111.5B(a)(3) of the PUA. (Comerge Response at 3-4)

Comverge states that, pursuant to Section 16-111.5B(a)(3) of the PUA, ComEd is required to conduct an annual solicitation process for purposes of requesting energy efficiency proposals from third party providers for cost-effective energy efficiency measures, incremental to those included in the utilities' energy efficiency and demand response plans approved by the Commission pursuant to Section 8-103 of the PUA, and then provide its assessment of these programs to the IPA so that IPA can include cost effective energy efficiency programs in its annual procurement plan. Comverge says ComEd's Section 16-115B(a)(3) solicitation process could have targeted peak demand reduction programs if ComEd had so chosen. In Comverges' view, if no analysis of EEAASR procurement was provided to the Commission by the IPA, this was due to the fact that no analysis of EEAASR procurement was provided by ComEd to the IPA, or could be provided by ComEd to IPA, because no proposals for peak demand reduction programs were solicited by ComEd. Comverge believes the lack of such analysis should not be used to bar the inclusion of the EEAASR Alternative, as modified by Staff, in the IPA's 2015 Procurement Plan. (Comverge Response at 4)

Ameren contends that the EEAASR Alternative should not be adopted because it is “premature” and gives rise to “too many fundamental issues.” Comverge argues that contrary to Ameren’s position, the EEAASR Alternative as modified by Staff is not premature because it needs to be part of the IPA’s 2015 Procurement Plan to assure that power supply costs are reduced as soon as possible for eligible retail customers. Comverge contends any remaining issues of how the EEAASR Alternative will be included in the Section 16-111.5B(a)(3) energy efficiency third-party RFP process can be addressed in a Staff-led workshop process. (Comverge Response at 4-5)

Ameren raised the issue that the scope of customers to be served under the EEAASR Alternative proposal has not been identified by the IPA. Comverge states that under Section 16-111.5B(a)(3)(C) of the PUA, Ameren (and ComEd) must identify new or expanded cost-effective programs or measures to energy efficiency programs offered by the utilities pursuant to Section 8-103 of the PUA that would be offered to all retail customers 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 from the utility under fixed priced bundled tariffs. Comverge concludes this is the scope of customers that should be included in the RFP regarding the EEAASR Alternative to be issued to third party energy efficiency providers. (Comverge Response at 5)

Ameren also contends that the EEAASR Alternative is silent on the details regarding the types of targeted bids that should be sought, citing the example that the peak periods for which demand reduction proposals will be solicited is not specified in the EEAASR Alternative. Comverge agrees with Ameren that specificity in the definition of peak periods will be required for the utilities to solicit peak period reduction proposals through the Section 16-111.5B(a)(3) third party energy efficiency RFP process. Comverge suggests that the peak period be defined, as it is in the IPA’s original EEAASR Proposal, as the hours of 3 P.M. to 7 P.M. CST on non-NERC holiday weekdays from June 1 through August 30. Comverge also suggests the actual peak period and other aspects of the targeted bids to be sought in the third party energy efficiency RFP process can be determined in the Staff-led workshop. (Comverge Response at 5-6)

Ameren sought clarity on whether traditional supply side rules or the demand side management rules currently in place for energy efficiency programs will govern the EEAASR Alternative procurement. Since the EEAASR Alternative procurement will ultimately be a Section 16-115.B(a)(3)(C) energy efficiency procurement, Comverge believes demand side management rules will apply. (Comverge Response at 6)

Comverge states that contrary to ComEd’s position that the EEAASR Alternative should only be explored in workshops, Staff supports the EEAASR Alternative approach proposed by the IPA where the Commission would mandate that ComEd and Ameren Illinois modify their Section 16-111.5B energy efficiency third party RFPs to specifically seek out peak demand reduction programs. Comverge says with one minor

adjustment, Staff supports the four specific modifications to the Section 16-111.5B third party energy efficiency RFP process which the IPA asked the Commission to require of the utilities. (Comverge Reply at 1-2)

Comverge supports Staff's approach to the EEAASR Alternative, rather than ComEd's approach, because it requires ComEd and Ameren to actually implement specific modifications to their Section 16-111.5B third party energy efficiency RFPs to solicit programs that would reduce demand during peak hours. Comverge says the approach proposed by ComEd of merely considering the EEAASR Alternative in workshops provides no assurance that peak demand reduction programs would actually be solicited. Comverge claims the ComEd approach does not assure that the goal of IPA's EEAASR Alternative of cost effective peak demand reductions would actually be achieved. (Comverge Reply at 2-3)

Ameren reiterated its previously stated position that the EEAASR Alternative should not be adopted because certain critical issues must be vetted and resolved prior to approval of any EEAASR procurement. Comverge understands that certain issues would need to be resolved prior to the utilities' actual procurement of an EEAASR resource. Comverge believes this does not mean that the unresolved issues need to be addressed prior to the Commission requiring the utilities to modify their Section 16-111.5B energy efficiency third party RFP process in the manner recommended by Staff, i.e., to include a request for proposals for programs to reduce peak demand of at least three years duration, to update the TRC test for these targeted programs to use a time-specific avoided energy cost, and to provide financial incentives appropriate to demonstrated peak period kWh reductions when estimated energy costs are greater than average. Comverge suggests the remaining details, such as what peak periods would be targeted, can be worked out in Staff-led workshops prior to issuance of the Section 16-111.5B third party energy efficiency RFPs by Ameren and ComEd. (Comverge Reply at 3-4)

In Comverge's view, the fact that certain details of the modification to the RFP process need to be addressed does not justify the Commission not approving the EEAASR Alternative, as modified by Staff, in the Commission's final order in this case. Comverge says if the Commission does not so act, there will be no mandate to the utilities to solicit proposals to reduce peak demand and consumers would have no assurance that cost-effective peak demand reduction programs will be solicited and implemented. (Comverge Reply at 4)

Comverge supports the alternative EEAASR proposal as modified by Briefs on Exception filed by the IPA, ComEd, and Staff. Comverge supports the IPA's proposaled revisions which would require EEAASR workshops to begin in January 2015 and be completed by mid-February 2015. (Comverge RBOE at 1-2)

9. Commission Analysis and Conclusions

The IPA proposes procuring a demand-side product delivered during the hours of 3 p.m. to 7 p.m. central standard time ("CST") on summer non-NERC holiday weekdays (e.g., 4-hour blocks for 5 days a week-other than July 4th if it falls on a weekday-for the period running from June 1 through August 30). To the extent load reductions during the super-peak time result in load shifting to other times, the IPA says the cost impact of the load reductions should net out the expected increased costs incurred by eligible retail customers at those other times. The IPA proposes to procure 3-year delivery contracts of EEAASR products and 100 kW demand-side resource blocks. The IPA proposes a late 2015 procurement with June 2016 delivery.

The IPA's proposal is supported by CUB and the AG. This primary proposal is opposed by Staff, ComEd, and Ameren. Among other things, those opposed to the primary proposal argue that energy efficiency is not a standard wholesale product and the only lawful way for the IPA to procure energy efficiency is pursuant to Section 16-111.5B of the PUA. They also complain that the primary proposal seeks to obtain energy efficiency from customers other than eligible retail customers.

As the Commission noted in Docket No. 13-0546, the list enumerated in 16-111.5(b)(3)(iv) contains the phrase "including but not limited to" which expands the list rather than limits it. (citing Docket No. 13-0546, Order at 94) In addition, the Order argued that products proposed under Section 16-111.5 must be evaluated on a "case-by-case basis" (*Id.)*. The Commission agrees with the IPA that the phrase 'standard wholesale products' cannot be static and it depends on the products that may be traded in wholesale markets at a given time. (IPA Response at 19)

Whenever the Commission is confronted with a unique product, as it was in Docket No. 13-0546, there must be an examination of the attributes of the product and whether those are consistent with other commonly traded products in the wholesale market. ComEd argues that these products must be routinely traded in a liquid market and have transparent prices that allow participants a degree of assurance that they are receiving fair market prices. (ComEd Objections at 16) The Commission agrees.

The question now becomes: do the energy efficiency products proposed by the IPA meet these criteria? Although price indices exist for some demand side products, the IPA has not shown that there are visible market prices for the super peak product. Nor is the record clear that the EEAASR products will lead to the "lowest total cost over time". The Commission believes that, based on the record in this case, these products should not be procured at this time. Nevertheless, as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA.

The IPA proposes the alternative approach of mandating the modification of the Section 16-111.5B third-party RFP process to specifically seek out programs that would

reduce demand during peak hours and provide additional incentives for those programs while remaining cost effective.

To approve this alternative approach, the IPA suggests the Commission should require the utilities to modify their Section 16- 111.5B third-party RFPs in the following manner.

- Specifically include a request for proposals for targeted programs that could identify and demonstrate reductions during peak periods.
- Update the TRC test for these targeted programs to use a time-specific avoided energy cost that would account for the higher price of power that is offset. This would allow for greater flexibility in programs that could bid.
- Provide an additional financial incentive to these programs for demonstrated peak period kWh reductions. This additional incentive could take on the form of the difference between the estimated average energy cost and the estimated energy cost during peak periods.
- For the reasons described in the IPA's core EEAASR procurement principles, the IPA believes these bids should be for programs of at least three-years in duration.

The alternative proposal is generally supported by Staff, ComEd, and Comverge. Staff opposes the third bullet point above regarding additional financial incentives. Comverge concurs in Staff's recommendation and the IPA appears to concede the additional financial incentives are not necessary. Ameren opposes the alternative proposal which both it and ComEd suggest is premature. ComEd and Staff believe workshops regarding this issue would be useful.

The Commission concurs with those parties that suggest energy efficiency is a valuable tool and should be pursued as a matter of policy and appreciates the efforts of the IPA to pursue innovative ideas. The Commission believes such efforts should be pursued pursuant to Section 16-111.5B of the PUA and hereby adopts the IPA's alternative proposal to inform the development and evaluation of the RFPs for programs submitted for consideration in the IPA's 2016 Procurement Plan.

The Commission directs the parties to commence workshops, coordinated by Staff, to pursue the IPA's alternative proposal, with such workshops beginning in January and concluding by mid-February to allow the workshops to inform development of the RFPs. Among other things, those workshops should consider whether an additional RFP for energy efficiency programs will be necessary, the duration of any such programs, whether the IL-TRM should govern these types of programs, and how such programs should be evaluated. To the extent practical, the Commission directs ComEd and Ameren to propose energy efficiency programs consistent with the IPA's goals when each provides its energy efficiency proposals pursuant to Section 16-111.5B of the PUA next year.

C. Incremental Energy Efficiency

1. Ameren's Position

Ameren notes that in Section 7.2.5.1, dealing with the Ameren Bid Review Process, the Plan contains a recommendation on page 80 that "ICC Staff hold workshops in early 2015 to examine if the inputs used for the Section 16-111.5B "total resource cost" test calculations should be different from those used for the Section 8-103 programs, and to develop recommendations for use in next year's filings." Ameren says the Plan also suggests that the workshops consider whether the IPA should develop and perform an independent TRC calculation with distinct inputs and assumptions rather than relying on inputs provided by the utilities. Ameren agrees that a workshop series on the issue should be held, but suggests that the workshops be conducted through the Stakeholder Advisory Group ("SAG") process. Ameren says the SAG process is set up to address resolution of such policy issues like calculation of TRC values and would allow all interested parties, including other utilities in Illinois not participating in this docket, to participate in addressing the issue. (Ameren Objections at 14-15)

Ameren reports that the IPA posed the following question to the Commission on page 79: "should the utilities be expressly encouraged to engage stakeholders in the review of third party bids and 'duplicative' program determinations?" In response to this question, Ameren states that the current models employed by the respective utilities already include stakeholder review. Ameren does not believe any "express" encouragement is needed or warranted. (Ameren Objections at 15)

NRDC complains about the manner in which Ameren conducted its review of third-party bids. NRDC contrasts ComEd, which "engaged stakeholders by means of a collaborative bid review process, as it has done every year since the inception of this policy,, with Ameren, which allegedly "did not engage stakeholders in a comparable process." Ameren believes this criticism is unfair and unwarranted. Ameren understands that Section 16-111.5B(a) requires a utility to "develop requests for proposals consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency and interested stakeholders." Ameren insists that is exactly what it did. Ameren says it drafted its RFP, sent its RFP out to the SAG for comment, solicited comments from them, and made adjustments to the RFP based on that feedback. Ameren claims no stakeholder complained about the process at that time. (Ameren Response at 8)

Ameren also says it shared the received bids with interested SAG members and elicited feedback on them within the timeframe that accounted for the conclusion of Ameren's most recent Plan approval docket. Ameren claims it also worked with the Department of Commerce and Economic Opportunity ("DCEO") on identifying potentially duplicative and competing programs so as to ensure compliance with the

PUA. Ameren says until NRDC filed its comments, no stakeholder complained of these actions. (Ameren Response at 8)

Ameren states that it is true that it did not delegate decision-making authority on bids received to other parties, but that is for good reason. Ameren says some SAG participants also serve as consultants for bidders, or are implementers themselves. Given the diversity of potentially overlapping interests held by some SAG participants, Ameren believes it would not be good practice to concede any authority to other parties who could have an interest in the outcome of the process. Ameren asserts this is a position that both the IPA and Staff endorse. (Ameren Response at 8-9)

NRDC states that the IPA has a "statutory responsibility to independently review Ameren [Illinois'] TRC calculations" and complains that such a review should have resulted in Ameren modifying the calculation of the TRC test applied to the bids received, but did not. NRDC seeks to have the Commission order the IPA to undertake another review of Ameren's TRC calculation and then order a modification, presumably so that certain programs "pass" the test. Ameren claims NRDC's position is unfounded and no modifications are necessary. Ameren asserts the IPA did conduct an independent review of Ameren's TRC calculations and, as a result of that review, the IPA did not recommend altering those calculations at this time because Ameren performed those calculations using reasonable assumptions per the review of Section 8-103 programs. In Ameren's view, that NRDC disagrees with the IPA's assessment and conclusion, does not provide a reason to second guess it, raises a specious "concern" regarding Ameren cost assessment. Ameren recommends that NRDC's recommendations be rejected. (Ameren Response at 9)

Staff requested that Ameren "elaborate on why only one behavioral program can be adopted." According to Ameren, only one behavioral program should be adopted because the proposed budget constrains the choice. Ameren states that in the last Ameren Plan 3 approval in Docket No. 13-0498, the Commission ordered the electric behavior modification program to be "transferred" to the IPA, but still be run in conjunction with Ameren's Section 8-104 gas behavior modification program. In order to maximize benefits, Ameren says it plans to continue to run these behavioral modification programs functionally as a dual fuel program, but through this docket will get approval for the electric portion of the total budget. Ameren claims the electric portion of the budget is necessarily constrained by the gas portion and in response to the Section 16-111.5B RFP, each bidder submitted a dual fuel program that would independently use up the total budget. Ameren states that if both programs were adopted, then the respective programs would be cut in half (assuming either vendor would have an interest in contracting for half of the incentives for which it bid). Ameren believes the correct path is to not have these programs compete at half budget (with increased administrative costs), but rather to have one program (whichever program the Commission chooses) run at full capacity so that the bid savings can be achieved. (Ameren Response at 9-10)

Ameren says NRDC and ELPC have attacked Ameren's inputs into the TRC test, as well as the way in which Ameren conducted the RFP bid review process. Ameren believes neither criticism has any merit. (Ameren Reply at 23)

Ameren claims the TRC test is a statutorily prescribed mathematic formula that relies heavily on subjective inputs which can change depending on when and how they are calculated. Ameren says it is important that the PUA places the responsibility of conducting analyses, including calculating the TRC test on two parties: the utilities in their submission to the IPA, and IPA itself, when preparing its Plan. Ameren states that here, both it and IPA complied with the PUA and conducted their own respective analyses to determine whether a potential program was "cost effective" or not. Ameren asserts that parties disagree with the outcome of these independent analyses does not provide an adequate basis to go back, stack the deck in favor of cost-effectiveness, and recalculate TRC so that the "close calls" that did not pass now do. (Ameren Reply at 23)

Ameren complains that NRDC and ELPC seek to do that by artificially inflating the "benefits" to include such things as demand reduction induced price effects ("DRIPE"), overly inflated "non-energy benefits," and marginal line losses. Ameren believes these changes, if ordered, would ensure that the "close calls" made by the IPA would become "cost effective" on re-review. Ameren claims these changes would be inappropriate to order at this time. Ameren agrees with ComEd's and Staff's positions on excluding DRIPE from the TRC analysis because it is not accurately characterized as a societal benefit or a societal cost. Moreover, to the extent there are questions surrounding the TRC analysis, Ameren suggests it would be more appropriate and productive for the resolution of these questions (including the topics of non-energy benefits and the use of average line losses v. marginal line losses) to be had at the SAG or during a workshop process where all interested parties can have the time and opportunity to participate, including those utilities and other parties not participating in this docket. (Ameren Reply at 23-24)

Ameren says NRDC and ELPC also accuse it of including "an inflated administrative adder." Ameren claims these accusations have no merit. According to Ameren, what NRDC characterizes as "inflated," includes the costs of necessary and important functions like education, marketing, evaluation, measurement and verification. Ameren says it has explained to parties, like NRDC, that certain adders were applied to the costs of running the proposed programs to account for those actions needed to promote the success of the programs. Ameren says those adders comprised: Portfolio Administration 5.0%; Evaluation, Measurement & Verification 3.5%; Education 2.5%, and Marketing 2.5%, with the total rounded to 14%. Ameren claims these approximate percentages have been used for years, including in Docket No. 10-0568 (Plan 2 approval); Docket No. 13-0498 (Plan 3 approval docket); Docket No. 12-0544 (2013 IPA Procurement Plan approval); and Docket No. 13-0546 (2014 IPA Procurement Plan approval). Ameren contends they have been applied consistently, and no party, including NRDC, has ever complained until now. (Ameren Reply at 24-25)

Ameren claims it uses consistent cost categories and adders for the Section 8-103 and Section 16-111.5B programs. Ameren states that unlike Section 8-103, which looks to the portfolio level TRC value for planning purposes, for Section 16-111.5B each program is required to pass the TRC test. Ameren says costs were moved from the portfolio level when analyzing the Section 8-103 Plan, to the program level for the proposed IPA programs. Ameren also claims many of the proposed incremental energy efficiency programs could be characterized as "new," which means they will likely have significant overhead costs as the program gets up and running. Ameren says these costs could include working on trade ally networks, developing marketing materials, coordination with other programs, and development and implementation of quality control/quality assurance programs. For incremental or expanded programs, Ameren believes that administration costs would stay the same or go up as the first participants in the program are/were the "early adopters," which take the least amount of education and marketing to gain as participants. Ameren says these estimated costs categories and considerations are not made up as NRDC seems to suggest, but based on Ameren's years of experience working in its service territory delivering energy efficiency to its customers. (Ameren Reply at 25)

Ameren argues that NRDC's other criticisms of costs are overstated, suspect and should be disregarded. In Ameren view, for NRDC to suggest to the Commission that Ameren's costs to administer, educate, market and evaluate its energy efficiency programs for costs are closer to $0 suggests a fundamental misunderstanding of what it takes to run and maintain successful energy efficiency programs. Ameren claims NRDC's suggestion that it has not considered the incremental costs of running new and expanded programs is wrong. Ameren asserts that for NRDC to make accusations "on information and belief" (when NRDC was a party to the docket) that Ameren did not apply an administrative adder in its TRC analysis when it submitted its compliance filing in Docket No. 13-0498 undermines NRDC's credibility. Ameren views it as unfortunate that NRDC and ELPC appear to scoff at allowing all interested parties, including those who are not in this docket, the opportunity to address and resolve TRC related issues at the SAG or workshops, with NRDC going so far as to pre-determine them as "unproductive." Ameren believes that if NRDC and ELPC seek to force the Commission's hand on this issue, then fair consideration of the facts warrants a finding that Ameren's administrative costs need no revisiting or revising in this docket as TRC related questions and concerns should be addressed first at the SAG or in workshops. (Ameren Reply at 25-26)

Ameren says ELPC and NRDC continue to push for an expanded role for interested parties during the RFP bid review process by casting Ameren as untimely and unwilling to engage. Ameren insists these accusations are false. Ameren claims it has a longstanding history of working with stakeholders, including ELPC and NRDC, to get their input on important issues and incorporate their suggestions when appropriate. Ameren says that approach continued during the RFP bid review process for the Plan. Ameren maintains it had stakeholders review the RFP before it went out and sought stakeholder feedback on the programs it was considering for inclusion in its submission to the IPA. (Ameren Reply at 26)

Ameren states that while the whole process was delayed and a bit more streamlined because of the overlap between the Plan 3 approval docket and the RFP bid process for this docket (certain issues relating to the transfer of programs were not resolved until March 2014), at no time did Ameren ever try to preclude stakeholder review or input. Ameren claims it tried to provide as much time as it could, given the circumstances, while still complying with the requirements of the PUA. Ameren says the timing issues that arose due to the Plan 3 approval docket will not be present this upcoming year, and Ameren agrees with Staff that stakeholder input is an important part of the RFP process. Ameren also agrees with Staff that no decision making authority can or should be transferred to the stakeholders and that the Commission should make clear that, ultimately, it is the utilities that have the responsibility to compile and provide the IPA with the submission called for by the PUA. In Ameren's view, the Commission need not enter any express order directing a certain kind of engagement or a prescribed methodology for reviewing bids. Ameren says it will continue to work with stakeholders (providing more time for review and input, as circumstances allow) to ensure their valued input gets received and, when appropriate, incorporated. (Ameren Reply at 26-27)

Ameren states that throughout this proceeding, it has maintained that an IPA Procurement Plan docket is not the right venue for addressing NRDC's concerns because it progresses on a compressed schedule and because not all interested parties have the time or opportunity to participate. Ameren says NRDC has ignored the Proposed Order's practical admonishments and continues to insist that the Commission modify the TRC test to suit its preferences in this expedited docket, despite the fact that NRDC must acknowledge that doing so would exclude several interested parties. Ameren believes that to modify the Proposed Order in the manner suggested by NRDC, however, would be inappropriate, and the Commission should affirm the Proposed Order's rejection of NRDC's exceptions. Ameren argues that to go back and start from square one on the work done by the parties to date would needlessly increase costs and delay implementation. Ameren claims NRDC has made no showing justifying such a result. Ameren asserts NRDC's attempt to co-opt this procurement plan docket to obtain a compulsory "re-do" of the bid review process, in which only NRDC's unilateral objectives are served and all "near miss" programs get included, is inappropriate and violates the spirit of the statute, which calls for a timely and orderly development, submission, review and approval of the IPA Plan. (Ameren RBOE at 9-10)

Ameren says Staff now advocates for an explicit Commission directive that certain TRC issues be made the subject of a separate docketed proceeding once the workshop process draws to a close, so that the TRC methodologies can be specified in Attachment B to the Technical Reference Manual. Ameren complains that, Staff's request for a separate docketed proceeding, proposed for the first time in its Reply comments, was not raised in a timely fashion such that interested parties could respond to the proposal. (Ameren RBOE at 10)

Even if the argument were properly preserved, Ameren believes the Proposed correctly identifies the path forward—first allow the workshop process to proceed and conclude and then determine whether or not a separate proceeding is necessary if the parties are unable to make progress in the workshop forum. Ameren remains committed to the workshop process and believes the forum would work well to address the many outstanding issues, like utility differences and appropriate cost/benefit analyses. Ameren believes the Commission should not affirmatively order a separate docketed proceeding at this time when there is a chance that issues can be collaboratively resolved through workshops. (Ameren RBOE at 11)

Ameren states that despite agreeing with Proposed Order that the TRC methodology issue generally should be sent to workshops, Staff also asks the Commission for "guidance" in regards to calculating NEBs. Ameren disagrees that "guidance" in this docket would be helpful to the workshop process. Ameren suggests it would only shift the focus of the debate and leaves too much room to interpretation of what the Commission's "guidance" means on the issue. Staff is concerned that Ameren's default NEBs adder does not represent a "quantifiable societal benefit," but its solution is to ask the Commission to "direct the utilities to include in the TRC calculations only societal benefits that have been quantified through a defensible study." In Ameren's view, such vague guidance begs the question of what constitutes a "defensible study" and shifts the debate to this issue instead of the NEBs themselves. (Ameren RBOE at 11-12)

According to Ameren, Staff seeks to slip in a requirement that the utilities begin "tracking" administrative costs at the program level for IPA programs to ensure a realistic estimate thereof in future Section 16-111.5B TRC screenings. Ameren complains that Staff's proposal was first raised in its Reply Brief, giving no party the opportunity to respond or develop a record on it. For this reason alone, Ameren believes the Commission should not change the Proposed Order's rejection of the proposal. Ameren also suggests Staff's recommendation could lead to the unintended consequence of increasing costs for the IPA programs (as the utilities try to comply with a vague directive to "track" administrative costs), which could also lead to an increase in administrative costs for the other energy efficiency programs offered by utilities as well. (Ameren RBOE at 12-13)

Staff asks the Commission to (a) direct the utilities to include within bid review documents details concerning the rationale for the duplicative/competing determinations as well as the facts supporting them and (b) direct the utilities to include in their confidentiality agreements with stakeholders a clause allowing stakeholders to present confidential information to the Commission on a confidential basis. Ameren indicates it does not object to substance of Staff's suggestions, but questions the need for explicit Commission directives on them. Ameren says it already provides information to the IPA regarding its rationale for the duplicative/competing determinations as part of its submission. And as to suggestion (b), Ameren says the parties already have the tools available to them through the respective regulations to share confidential information with the IPA or the Commission. Ameren believes there is no confidentiality problem

here requiring a solution, nor is there a need for the Commission to get involved with drafting non-disclosure agreements for SAG members and Staff's exception on this issue should not be adopted. (Ameren RBOE at 14-15)

Staff asks (a) that the Commission clarify that the two programs are competing and not duplicative; (b) that the Commission direct the IPA and the utilities to coordinate with duplicative program vendors in advance of future procurement plan filings to disaggregate program components so as to allow direct comparisons; (c) that the Commission clarify that nothing in the order should be read to limit Ameren's flexibility under Section 8-104; (d) that the Commission find that past evaluation results of third party vendor programs would be helpful to present in the plan; (e) that the Commission find that considering whether a vendor is well-established is a reasonable factor to consider; and (f) that the Commission select Behavioral Energy Efficiency for implementation, based on a list of eight reasons provided at Staff. Ameren does not agree with Staff's request that the Commission "clarify" that the programs are competing and not duplicative. According to Ameren, the programs are duplicative because they, among other things, serve the same customers and have duplicative attributes. (Ameren RBOE at 15)

2. NRDC's Position

NRDC objects to the IPA's deferral of the issue of whether utilities should be expressly encouraged to engage stakeholders in the review of third party program bids. Rather, NRDC recommends that the Commission revise the Plan or otherwise expressly encourage utilities to develop requests for proposals with input from and collaboration with interested stakeholders throughout the process. (NRDC Objections at 2)

Pursuant to Section 16-111.5B(a) of the PUA, "the utility shall develop requests for proposals consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency and interested stakeholders." In NRDC's view, the IPA and Commission, therefore, have a clear mandate allowing them to not only "encourage," but require that utilities participate in a collaborative process with stakeholders. (NRED Objections at 3)

NRDC objects to the IPA decision not to seek to examine further or alter Ameren's TRC calculations for the three programs with a TRC of greater than 0.9 and less than 1.0. NRDC recommends that the calculations for these three programs be adjusted so that demand reduction induced price effects, marginal line losses, and an accurate non-energy benefits adder are included and any non-essential administrative costs are excluded. (NRDC Objections at 2-3)

NRDC says the IPA has the statutory responsibility to independently review Ameren's TRC calculations. NRDC states that pursuant to Section 16-111.5B(a)(4) of the PUA, the IPA "shall include in the procurement plan…energy efficiency programs and measures it determines are cost-effective" NRDC says in the Draft Plan, the IPA

has stated that it understands "cost-effective" to mean "a program has met basic utility RFP requirements…and passes the total resource cost test." NRDC believes drawing these principles together, the IPA should not merely defer to Ameren's TRC results, but "shall" perform its own, independent calculation as to each program. NRDC asserts the IPA should not forego this obligation especially as to Ameren's "near miss" programs that could very well qualify after benefitting from small numerical adjustments. (NRDC Objections at 3-4)

NRDC states that pursuant to Section 1-10 of the IPA Act, a TRC calculation shall account for "other quantifiable societal benefits." NRDC claims DRIPE is a widely recognized and quantifiable benefit of improved energy efficiency. NRDC states that in September of 2014, Resource Insight, Inc. produced a study demonstrating that the DRIPE benefit significantly reduced rates paid by Illinois electricity consumers. According to NRDC, this study demonstrates that the DRIPE benefit is about 20% - 40% of avoided energy costs for a measure with a 15-year life and higher percentages for measures with shorter lives. NRDC argues that as a "quantifiable societal benefit," the law necessitates that DRIPE be included as part of Ameren's TRC calculations. (NRDC Objections at 4)

NRDC contends the non-energy benefit of energy efficiency is another "quantifiable societal benefit" that should be independently calculated by the IPA and included as part of Ameren's TRC calculations. NRDC says non-energy benefits, especially for low-income customers, can be dramatic in their capacity to improve the lives, safety, health, and comfort of customers - often having more value than the associated reductions in energy costs. NRDC says Ameren has made it a practice to include a 10% non-benefits adder, which NRDC regards as insufficient. (NRDC Objections at 4)

NRDC states that pursuant to Section 1-10 of the IPA Act, a TRC calculation must account for the "avoided electric utility costs." NRDC claims it is self-evident that a utility should evaluate avoided costs by the most accurate means. NRDC believes calculating marginal line loss avoided, as opposed to average line loss, provides a far more accurate estimation of actual capacity savings. NRDC argues that line losses grow exponentially with load and are most pronounced during peak hours. NRDC asserts that marginal line loss calculations, unlike those for average loss, are able to account for line losses as a square of the load. NRDC says an energy efficiency program's savings calculated using marginal line loss is on average 1.5 times greater than average losses. To the extent that Ameren's TRC calculations used average line loss when assessing the three "near miss" programs, NRDC believes those calculations should be modified. (NRDC Objections at 4-5)

NRDC is concerned that Ameren's cost assessment that it applied as part TRC used overstated assumptions as to administrative costs. NRDC suggests these costs may not only be inflated, but illusory. NRDC also suggests the IPA should carefully assess and itemize Ameren's costs, excluding those that are not warranted. (NRDC Objections at 5)

According to NRDC, a brief recounting of the application of AIC's 2014 "model" for stakeholder review makes plain the need for "express encouragement." NRDC says a few days prior to July 7, 2014, AIC disclosed to NRDC, the AG, and the ELPC, hundreds of pages of documents related to the third party proposals submitted to AIC for potential inclusion in the IPA's procurement plan. Prior to providing access, NRDC states AIC required these stakeholders to sign a non-disclosure agreement. NRDC says on July 7, 2014, a week before it was required to submit its analysis and recommendations to the IPA, AIC met with the signors of the non-disclosure agreement to present a summary of its submission. NRDC states that the meeting lasted approximately 1½ hours and during the meeting and in subsequent emails, NRDC conveyed several concerns about AIC's analysis and requested more information. While not unresponsive, NRDC claims AIC did not fully comply with NRDC's information requests, most importantly, those regarding AIC's cost-effectiveness screening of Section 111.5B programs. NRDC says before AIC could comply, the July 15, 2014 deadline for submittal to the IPA arrived. (NRDC Response at 4)

In NRDC's view, AIC's engagement with stakeholders was insufficient in that it did not afford stakeholders sufficient time to review AIC's submission, acquire from AIC all necessary information, and, thereafter, engage with AIC in an attempt to resolve their concerns. (NRDC Response at 4)

NRDC states that by contrast, ComEd conducted the preparation of its submittal to the IPA, from beginning to end, in partnership with stakeholders. In early April of 2014, after issuing its RFP and prior to receiving proposals in response, NRDC says ComEd reached out to stakeholders interested in participating in a review of the proposals and established a schedule for a collaborative process. As soon as the proposals were received, NRDC indicates ComEd shared them with the participating stakeholders. In May of 2014, NRDC says ComEd held a series of conference calls with those stakeholders to consider their feedback and, to the extent possible, reach a consensus. NRDC asserts that well in advance of each conference call, ComEd provided participating stakeholders with all relevant documentation, including summaries of the collaborative discussions to date. NRDC claims as a result of this partnership, all questions and points of dispute were resolved and ComEd's submission to the IPA was fully endorsed by NRDC and other participating stakeholders. (NRDC Response at 4-5)

NRDC says while not overtly objecting to the IPA's suggestion that Commission Staff hold workshops in 2015 to "examine if the inputs used for the Section 16-111.B TRC calculations should differ from those used for the Section 8-103 programs and to develop recommendations for use in next year's filings," AIC believes that any such workshops should be conducted instead by the SAG. (NRDC Response at 5)

NRDC says while it is willing to engage in further dialogue with utilities, it is doubtful that a "workshop" setting, whether at the SAG or held by Commission Staff, is

the proper forum to resolve differences regarding the appropriate TRC inputs. (NRDC Response at 5)

NRDC continues to retain fundamental concerns that AIC undervalued the net benefits of several energy efficiency programs in its cost-effectiveness screening, thereby resulting in the forfeiture of significant cost-effective resources. Specifically, NRDC claims AIC's calculations may have failed to adequately account for demand reduction induced price effects, non-energy benefits ("NEBs"), and avoided line losses. NRDC says it is important to note that these proceedings are not the first time NRDC has raised these concerns. NRDC says it and others have been insisting for years at the SAG and in our direct communications with utilities that they incorporate DRIPE, NEBs, and marginal line losses into their TRC calculations for purposes of Section 8-103 and Section 111.5B programs. NRDC asserts that while the utilities have made minor adjustments in response, yawning differences remain and appear irreconcilable. (NRDC Response at 5-6)

NRDC contends it would be inadequate for the Commission to merely sign off on AIC's cost-effectiveness screening for purposes of this year and wait until next year to "talk through" issues upon which the parties are firmly divided at future "workshops." In NRDC's view, such an approach would not only result in undervalued and potentially beneficial energy efficiency programs remaining sidelined, but would be unproductive. NRDC insists the issue of whether DRIPE, NEBs, and marginal line losses should be included in a utility's TRC calculation is ripe for judgment and NRDC urges the Commission to address these issues in this proceeding. (NRDC Response at 6)

NRDC asserts that in mandating that DRIPE be included as part of this year's TRC calculations, the Commission would merely bring Illinois' cost-effectiveness screenings up to date with current industry best-practices as recognized by a number of other jurisdictions and leading voices in the field. NRDC claims DRIPE has been used in cost-effectiveness screenings in New England for years. (NRDC Response at 6)

According to NRDC, if the TRC as applied in Illinois is truly meant to incorporate all quantifiable impacts to participants, then NEBs must be accurately calculated and included. NRDC says the utility cost test ("UCT") compares a utility's system costs of a particular action to the utility's system benefits. In the case of implementing an energy efficiency program, NRDC says the UCT compares the program's spending to the avoided utility system costs. NRDC states the TRC builds upon the UCT by incorporating the impacts on program participants. When applying the TRC, NRDC says Illinois utilities carefully ensure that an efficiency program's participant costs are identified and properly included as part of the cost-effectiveness screening. According to NRDC, utilities must similarly account for all participant benefits, including NEBs, otherwise, the TRC is skewed against efficiency. (NRDC Response at 7)

NRDC claims NEBs have historically been excluded in Illinois from the TRC calculation. NRDC understands that AIC has recently begun using a 10% NEBs adder in its cost-effectiveness screening. While a step forward, NRDC believes 10% is an

overly conservative estimation, particularly for more comprehensive energy efficiency programs. NRDC suggests with respect to home weatherization retrofit programs, the evidence suggests that participants' NEBs are 100% to 400% of the value of their energy bill savings. (NRDC Response at 7-8)

NRDC requests that the Commission require that utilities, prior to using a standard adder, first reference the technical literature related to the type of program being considered in an effort to develop a more accurate estimate of actual NEBs. To the extent that such literature is unavailable, then NRDC suggests conservative 15% and 30% adders could be used for non-low income and low income programs, respectively. (NRDC Response at 8)

NRDC claims those values were adopted by the Vermont Public Service Board after extensive comment and analysis. In adopting the 15% value, NRDC says the Vermont Board stated that "15% is on the lower end of the range" and that it would be appropriate to "revisit the estimate" during each biennial review of avoided costs. (NRDC Response at 8)

According to NRDC, marginal line losses, as opposed to average loss rates, more accurately reflect the avoided energy costs derived from an energy efficiency program. NRDC says marginal energy line losses are typically equal to approximately 150% of average energy losses and marginal peak losses are typically on the order of 250-300% of average energy losses. NRDC asserts that ComEd, having conducted its own internal assessment of this issue has recently modified its own cost-effectiveness screening of programs submitted pursuant to Sections 8-103 and 16-111.5B of the PUA to use marginal line losses. NRDC complains that AIC continues to undervalue its RFPs by using average line losses. (NRDC Response at 7-8)

NRDC believes that further workshops before the SAG involving stakeholders, who are resolutely divided, to decide a binary issue that weighs decidedly in favor of using marginal line losses are unnecessary and would only inject further delay. NRDC says it and other stakeholders have been urging Ameren to adopt the use of marginal line losses for several years, both directly and at the SAG. NRDC says Ameren has thus far indicated that it does not intend to change the line loss rate it uses for screening. (NRDC Reply at 1-2)

With respect to marginal line losses, NRDC requests:

1. Formally require Ameren to incorporate marginal line losses in all future Section 16-111.5B cost-effectiveness screenings.
2. If the Commission is not going to *sua sponte* include in the Plan Ameren's Section 111.5B programs with TRC of over 0.9 and under 1.0 ("near miss" programs), require that these programs be rescreened using marginal line losses. If Ameren does not have an analysis of its own marginal line loss rates, require that Ameren assume that marginal energy losses are 150% of average energy losses (i.e. 10% rather than the current 6.7% stated in Ameren's Response to NRDC's Data Request, 1.03) and the marginal peak kW loss factor

> is 250% of its average energy loss factor (17% rather than the 7.1% to 7.8% stated in Ameren's Response to NRDC's Data Request, 1.04). If this TRC adjustment is sufficient to revive any of these Section 16-111.5B programs, include them as part of the Plan.

(NRDC Reply at 2-3)

NRDC is also concerned that AIC may have overstated the costs of the programs proposed for IPA procurement. In particular, NRDC is concerned by the apparent inclusion of an inflated administrative cost adder. NRDC says it requested and received information from the IPA regarding its review of AIC's adder included as part of AIC's cost-effectiveness screening of three energy efficiency program proposals with a TRC of over 0.9 and below 1.0. According to NRDC, the IPA suggested that AIC calculated the adder by dividing AIC's total Section 8-103 programs' overhead costs for administration, evaluation, education, and marketing (i.e. all administrative costs minus costs for emerging technologies) by its total Section 8-103 program costs. Employing this methodology, NRDC has calculated what it assumes to have been the adder that AIC used for screening the IPA program using figures set forth in AIC's Plan 3 Corrected Compliance Filing. NRDC states that by dividing $19.81 million (the overhead costs for AIC's Section 8-103 programs' portfolio administration, EM&V, education, and marketing) by $146 million (the three-year total for AIC's section 8-103 programs' costs), NRDC arrived at the numerical figure of approximately 0.14 or a 14% adder. (NRDC Response at 9-10)

NRDC states while the IPA purportedly confirmed that the resulting adder was based on the same model and inputs AIC used to screen its Section 8-103 programs, it did not specifically inquire about whether the adder was based on empirical information related to any actual or projected marginal program costs. (NRDC Response at 10)

NRDC claims AIC did not screen its Section 8-103 programs with an administrative adder. NRDC asserts TRC benefit-cost ratios provided in AIC's Plan 3 Compliance Filing do not include the allocation of administrative costs, rather, the administrative costs were applied only to portfolio-level screenings. In NRDC's view, the IPA appears to be incorrect in its Response when it says that the application of the adder was based on the same model and inputs AIC used to screen its Section 8-103 programs. (NRDC Response at 10)

According to NRDC, the adder appears to have been calculated using AIC's average overhead costs for its Section 8-103 programs, not an estimate of the incremental overhead costs. NRDC believes this is inappropriate in view of the fact that in that same subparagraph, the IPA quotes Section 16-111.5B, providing that the cost-effectiveness screen is used to identify "new or expanded cost-effective energy efficiency programs that are incremental to those included in…plans approved by the Commission pursuant to Section 8-103." NRDC asserts if the screening is to focus on the incremental savings the programs produce, it must also focus on the incremental (or marginal) costs that they impose. (NRDC Response at 10)

NRDC suggests the incremental administrative costs that AIC would incur managing its Section 16-111.5B programs would likely be significantly lower than the average costs incurred managing its Section 8-103 portfolio. NRDC says Section 16-111.5B programs, unlike Section 8-103 programs, are intended to be "turn-key." NRDC asserts by using Section 8-103 programs' administrative costs as a basis for the adder, AIC improperly factored in non-existent education and marketing costs. NRDC says these costs represent nearly 40% of AIC's Section 8-103 programs' overhead. NRDC contends if these "non-existent" costs are excluded, NRDC calculates that AIC's presumed adder could be reduced from 14% to 8.5%. (NRDC Response at 11)

NRDC claims the adder redundantly incorporates many of the Section 8-103 programs' fixed administrative costs. According to NRDC, administrative costs do not usually increase linearly or proportionally with budget. NRDC suggests AIC needs only one portfolio-level Energy Efficiency manager to implement Sections 8-103 and 16-111.5B programs. NRDC considers two programs that are identical except that one has twice the budget because it offers a higher incentive. NRDC claims the costs of managing, marketing, and evaluating these programs will not differ by a factor of two, rather, the costs should be nearly identical. NRDC believes the adder should not incorporate any costs that would have already been incurred as part the administration of Section 8-103 programs. (NRDC Response at 11)

NRDC contends applying a standard, "one-fits-all" adder when evaluating specific energy efficiency programs with highly variable administrative costs can, in certain situations, entirely undermine confidence in the adder as representative of actual costs. NRDC suggests the Multi-Family Major Measures Program, which was included in the Plan because it passed TRC despite the adder, has a budget of approximately $16.4 million annually. NRDC says a 14% administrative adder would be equal to approximately $2.3 million annually, which could be used by AIC to employ 12 to 15 additional full-time employees ("FTEs"), and in NRDC's view is an overstatement of the actual cost of administering this program. (NRDC Response at 11-12)

While NRDC does not object to AIC recouping administrative costs, NRDC believes these costs should be closer to $0 than the 14% apparently assumed. NRDC notes that ComEd did not assume any additional administrative costs in its screening of Section 16-111.5B programs. In NRDC's view, administrative costs should be calculated individually based on the nature and needs of each program. NRDC would expect these costs to include whatever additional staff costs AIC would incur to manage a program (given the "turn-key" nature, less than one FTE per program) as well as expenses incurred evaluating a program's performance. NRDC maintains these costs should be included in program cost-effectiveness screening only to the extent that AIC would rely on funding beyond what was is already included as part its Section 8-103 portfolio. (NRDC Response at 12)

NRDC believes that convening a "workshop" to consider AIC's administrative adders to be unnecessary. NRDC says the application of AIC's adder is neither a policy nor methodological issue that is best resolved through debate and negotiation, rather,

its application and valuation by AIC proceeds from incorrect arithmetic that demands correction, not further stakeholder deliberation. (NRDC Response at 12)

NRDC requests that the Commission immediately approve for inclusion in the Plan AIC's three proposals with a TRC of over 0.9 and under 1.0 on the grounds that these programs would be cost-effective after either a reasonable adjustment to the administrative adder and/or the proper application of DRIPE, NEBs, and/or marginal line losses; or require that AIC recalculate the TRC for those RFPs with a TRC of over 0.9 and under 1.0 so as to include DRIPE, NEBs, and marginal line losses and exclude the administrative adder. NRDC also requests that the Commission require utilities to incorporate DRIPE, NEBs, and marginal line losses into all future Section 16-111.5B cost-effectiveness screenings; and prohibit the use of a standard administrative adder in all future Section 16-111.5B cost-effectiveness screenings and set forth guidelines, consistent with the foregoing discussion, informing the calculation of administrative costs. (NRDC Response at 12-13)

Staff understands NRDC's position to be that utilities should be precluded from including in their cost-effectiveness screenings the administrative costs of implementing their Section 16-111.5B programs. With that understanding, Staff pronounces that NRDC's alleged position is inconsistent with the definition of TRC found in the IPA Act. In support, Staff observes that Section 16-111.5B programs should be screened for cost-effectiveness individually as opposed to in the aggregate (i.e. at the portfolio level) like Section 8-103 programs.

NRDC states that contrary to Staff's assessment, it does not object to Ameren including as part of its cost-effectiveness screening a reasonable estimation of the incremental costs it will incur administering Section 16-111.5B programs. Rather, NRDC objects to Ameren using what it believes is an exorbitant, boiler-plate "adder" derived from its forecast of the average cost of administering its Section 8-103 programs. (NRDC Reply at 3)

NRDC maintains that Ameren's assumption that the incremental administrative costs of a Section 16-111.5B program will be the same as the average administrative cost of a Section 8-103 program is unsubstantiated and, unreasonable. NRDC insists the actual costs of administering a Section 111.5B program should be significantly lower than the average cost of administering a Section 8-103 program. NRDC expects incremental administrative costs associated with IPA programs to have only two components: 1) evaluation costs; and 2) added labor costs to oversee the contracts. Based on NRDC's internal calculations, it suggests administrative costs would likely be no more than 8% of program costs for smaller programs, no more than 5% for medium-sized programs, and 3-4% for larger programs. (NRDC Reply at 3-4)

NRDC asserts that, if Ameren's adder were changed to the values it estimated: any small program that initially screened with a TRC of 0.95 would now pass, any medium-sized program that initially screened with a TRC of 0.92 would now pass, and any large program that initially screened with a TRC of 0.91 would now pass. NRDC

suggests it is likely that the inflated adder used by Ameren is the sole reason the "near miss" programs are wrongfully being excluded from the Plan. (NRDC Reply at 4)

With respect to Ameren's administrative adder, NRDC, therefore, requests:

1. Formally require that utility administrative cost adders included in Section 16-111.5B cost-effectiveness screening reflect forecasts of only the incremental utility costs likely to be incurred.
2. If the Commission is not going to *sua sponte* include in the Plan Ameren's three "near miss" programs, require that these programs be rescreened using 4% adder for larger programs, a 5% adder for medium-sized programs, and an 8% administrative adder for smaller programs.

NRDC maintains DRIPE is a "quantifiable" "societal benefit" that should be included in the Illinois TRC. NRDC claims numerous national and regional publications from the Regulatory Assistance Project ("RAP"), National Efficiency Screening Project, and Northeast Energy Efficiency Partnership have verified that DRIPE should be used in TRC cost-effectiveness screenings. (NRDC Reply at 6)

NRDC says in 2011, the Lawrence Berkeley Laboratory ("LBL") considered whether the proposed efficiency standard for water heaters resulting in lower natural gas prices (i.e DRIPE) represented a societal net benefit or merely a transfer of wealth. NRDC claims the LBL found that the natural gas producers make investment decisions based of profitability of a proposed project, which is influenced by factors such as expected price, demand, and cost of production. NRDC also claims the LBL found further that when producers were able to include the effects of new efficiency standards into the forecasts of demand and price used to make their investments, the introduction of the new efficiency standards should not affect the profitability of those investments. According to NRDC, once energy producers are willing to recognize DRIPE, they can take steps to avert a reduction in profits. NRDC asserts the LBL study was recently seized upon by the Vermont Public Service Board as the primary basis to reverse its prior ruling cited by Staff and include DRIPE in its cost-effectiveness screening of energy efficiency measures. (NRDC Reply at 6-7)

NRDC also cites a recent paper presented at the American Council for an Energy Efficiency Economy, which it says summarized regulatory economic thinking on the issue as follows:

> In practice, the target group of the TRC and the society of the Societal Test do not generally include everybody. For example, regulators have always valued oil at its market price, not the price of production in Texas or Saudi Arabia, excluding the benefits to the producers of increased oil use. Similarly, power purchases, whether from the competitive market, an independent power producer, or a neighboring utility, are invariably valued at the price charged, ignoring the generator's profits. By that standard, the efficiency-induced reduction of prices to consumers should be counted as

> a TRC and Societal benefit, but the reduced income to fuel suppliers and power generators should be excluded, with price suppression counted as a benefit under those tests. (NRDC Reply at 7)

NRDC claims there are a number of other energy efficiency benefits and costs that are included in the TRC that, using Staff's logic, should also be understood as merely a transfer of wealth. NRDC says the incremental costs of energy efficiency measures that, without controversy, are included in the cost-effectiveness screening in Illinois are typically based on the price that the end use consumers pay for efficient products. NRDC says those consumer costs include profits to numerous parties along the supply chain, such as contractors, retailers, distributors, manufacturers, and others. NRDC argues that using Staff's logic, the portion of incremental efficiency measure's costs that are associated with profits along the supply chain should be regarded as transfer payments and removed from the TRC. NRDC also says the third-party vendors who deliver the efficiency programs on behalf of the utilities and/or IPA are themselves earning profits for their services. NRDC contends that using Staff's logic, those profits would also need to be subtracted from program delivery costs. In NRDC's view, Staff's logic, leading it to conclude that DRIPE is a transfer of wealth, is not only fatally flawed in that it proves too much; it is inconsistent with the current application of cost-effectiveness screening in Illinois. (NRDC Reply at 8)

NRDC claim that even if the Commission finds that DRIPE is not a "societal benefit" or constitutes merely a transfer of wealth, it should still be included as part of the TRC as a benefit that "accrue[s] to the system and the participant in the delivery" of energy efficiency measures. NRDC says pursuant to Section 1-10 of the IPA Act, TRC benefits include "…avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs…" NRDC believes lower energy prices paid by a "participant" in energy efficiency programs is a "benefit." (NRDC Reply at 8)

NRDC also argues that lower energy prices produced by DRIPE and paid by consumers everywhere is also a benefit that "accrues to the system" in that the system's purposes are advanced. NRDC says pursuant to the IPA Act, the IPA is to "develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time." NRDC says the PUAs goal is to achieve "efficiency: the provision of reliable energy services at the least possible cost to the citizens of the State; in such a manner that…utilities are allowed a sufficient return on investment…" NRDC claims reading the IPA Act and PUA together, the "system" is primarily designed to: 1) ensure reliable electricity; 2) provide energy at the most "affordable"/"least possible cost;" and 3) ensure utilities are fairly compensated. NRDC repeats DRIPE is a "benefits that accrues to the system" in that it lowers energy consumer costs without reducing profits to the point of depriving the utilities of fair compensation. (NRDC Reply at 9)

NRDC does not dispute that DRIPE's benefits are temporary or subject to erosion over time. NRDC states that under the subsections "Price Elasticity," "Resource Retirements and Additions" and "DRIPE Decay Summary," the DRIPE study acknowledges that the DRIPE benefits decline over time. NRDC says the study's estimates of the benefits of DRIPE for efficiency measures with different measure lives explicitly accounts for the erosion of price effects over time. NRDC says the DRIPE study estimates that an efficiency measure with a 15 year life will produce DRIPE benefits equal to between 20% and 40% of the direct avoided energy cost after adjusting for the erosion over time of the DRIPE. In NRDC's view, Staff's observation that DRIPE is temporary does nothing to further the discussion or undermine NRDC's position. NRDC asserts Staff merely points out a factor that NRDC has acknowledged and assimilated as part of its analysis without offering a valid reason to question that analysis. (NRDC Reply at 9-10)

According to NRDC, Staff's suggestion that the DRIPE Study may confuse cause with correlation is misguided at a basic level. NRDDC claims it is well established in micro-economic theory that lower demand leads to lower prices. NRDC asserts RTOs recognize this implicitly, which is the reason they routinely graph price as a function of demand (i.e. prices against loads). (NRDC Reply at 10)

NRDC also claims Staff's assertions that the DRIPE Study confuses correlation with cause, that the model used in the DRIPE study lacks "sophistication," or that "it is very likely that there is feedback between prices and load that would cause the benefits to be overstated" are unsupported. NRDC says it is not in a position to reply to Staff's "proof by assertion" without some further statement of explanation that could be regarded as a basis. (NRDC Reply at 10)

NRDC says Staff's contention that "it is very likely that there is feedback between prices and load that would cause the benefits to be overstated" suggests that Staff believes that lower prices lead to higher demand. NRDC claims the DRIPE study specifically addressed and accounted for the potential for "feedback" by using estimates of price elasticity for ComEd's service territory to demonstrate that though prices do lead to slightly higher demand, the feedback would likely offset no more than 2% of the DRIPE effect in the short term and no more that 3% in the long term. (NRDC Reply at 10-11)

NRDC believes Staff's contention that some of the DRIPE study's results were implausible is correct, as is its observation that the DRIPE study's rejection of those results was proper. NRDC contends that Staff fails to recognize or acknowledge that the few implausible results have no bearing on the study's bottom-line result that a 1% reduction in load leads to approximately a 2% reduction in price. NRDC asserts this result was found for every model run for every combination of regions around and including ComEd and/or Ameren service territory. (NRDC Reply at 11)

NRDC avers the implausible results only occurred when the analysis attempted to determine the degree to which different sub-regions were producing the price

reduction. NRDC claims the DRIPE study found that a 1% reduction in off-peak load across the entire region of ComEd plus MISO would lead to a 2% reduction in off-peak prices for ComEd. NRDC says when the DRIPE study's analysis attempted to parse out the specific contribution of each of the four sub-regions of ComEd, MISO Central, MISO East, and MISO West to that price reduction, the regression results suggested implausible negative coefficients for some sub-regions that were more than offset by surprisingly large coefficients in others. NRDC states that the overall effect in all sub-regions remained a 2% reduction in prices. According to NRDC, while the DRIPE study's "model" cannot identify which sub-region has the greatest influence on price reduction for any given model run, it can be relied upon for the overarching conclusion that lowering loads by 1% leads to approximately a 2% reduction in prices. (NRDC Reply at 11-12)

NRDC contends the DRIPE study's results are not unique. NRDC asserts the price suppression effect estimated for efficiency programs in Illinois is consistent with the results of three other studies of price effects in New England and PJM, as well an IPA study on the effects of wind generation on prices in Illinois. According NRDC, including DRIPE in cost-effectiveness screenings would not be unique to Illinois. NRDC asserts half of the thirteen competitive wholesale energy market (i.e. restructured) jurisdictions incorporate DRIPE as part of their cost-effectiveness screenings. NRDC says that DRIPE is only a significant benefit in states that have effectively restructured such that they are relying on a truly competitive wholesale market that can react to changing demand. NRDC states that the restructured States that currently include DRIPE are Massachusetts, Rhode Island, Connecticut, Delaware, Maryland, and the District of Columbia. According to the American Council for an Energy Efficiency Economy, all but one of the remaining States that do not include DRIPE – Maine, New York, New Jersey, Pennsylvania, Ohio, and Texas - have less aggressive or sophisticated efficiency program portfolios or policies than Illinois. (NRDC Reply at 12-13)

NRDC claims Staff has offered a readily rebuttable critique of NRDC's literature and an opinion from the Vermont Public Service's Board that was recently reversed. NRDC says other than its unsuccessful attempt at undermining NRDC's technical and precedence based position, Staff provides nothing in its place substantiating that DRIPE is in practice "pecuniary externality." (NRDC Reply at 13, RBOE at 1-5)

NRDC believes it has more than overcome any presumption in favor of maintaining "past practices." NRDC understands that the Commission may not presently be in a position to determine the precise numerical value of the DRIPE input and may defer to stakeholders at a future workshop to analyze and develop the proper coefficient. NRDC suggests these workshops will likely be far more productive if the Commission formally recognized DRIPE as an appropriate TRC input so that stakeholders can move forward on determining its numerical value as opposed to persisting in maintaining their respective positions from this proceeding. (NRDC Reply at 13-14)

With respect to DRIPE, NRDC requests:

1. That the Commission formally recognize DRIPE as a benefit that should be included as part of future cost-effectiveness screenings.
2. If the Commission does not believe it has sufficient evidence to adopt a numerical value for DRIPE, defer quantifying the precise input to future stakeholder workshops.
3. If the Commission is not going to *sua sponte* include in the Plan Ameren's three "near miss" programs, require that these programs are rescreened using NRDC's proposed estimates of DRIPE.

(NRDC Reply at 14)

ComEd regards NRDC's argument in support of the inclusion of non-energy benefits as part of TRC calculations as "conclusory" and without adequate support. ComEd states further that including non-energy benefits is improper, "regardless of whether they exist," as "NRDC cannot quantify the value of 'lives, safety, health, and comfort" of customers who participate in energy efficiency programs."

NRDC claims NEB's have been successfully quantified in numerous studies. In NRDC's view, simply because it may be challenging or require a more searching effort to estimate NEBs does not mean that they should be summarily excluded from the cost-effectiveness screening. NRDC claims uncertainty in estimating NEBs would merely put them on par with other costs and benefits currently factored into the TRC that are necessarily imperfect forecasts of future monetary values. (NRDC Reply at 15)

NRDC says it is sensitive to the fact that the Commission may not presently be in a position to determine the precise numerical value of NEBs inputs, which are necessarily highly program specific, and may defer to stakeholders to analyze and develop the proper coefficient(s) at future workshops. NRDC claims that merely deferring the entire issue to future workshops uninformed by the Commission's specific findings that future cost-effectiveness screenings shall include NEBs will not work. (NRDC Reply at 15)

NRDC says it and other stakeholders have urged the utilities in the past to adopt NEBs, DRIPE, and marginal line losses. NRDC says the utilities, to various degrees, have refused and, to date, have given no indication that they are willing to reconsider. NRDC fails to discern the benefit of again imploring Ameren and ComEd to reverse course on NEBs, DRIPE, and/or marginal line losses at the SAG. (NRDC Reply at 15-16)

With respect to NEBs, NRDC, therefore, requests that the Commission:

1. Formally recognize NEBs as a benefit that should be included as part of future cost-effectiveness screenings.
2. In future proceedings require that utilities, prior to using a standard adder, reference the technical literature related to the type of program being considered in an effort to develop a more accurate estimate of actual NEBs.
3. Defer quantifying a default NEBs adder to future stakeholder workshops.

4. If the Commission is not going to *sua sponte* include in the Plan Ameren's "near miss" programs, require that these programs are rescreened using a 15% NEBs adder.

(NRDC Reply at 16)

ComEd contends that DRIPE should not be included in cost-effectiveness screenings. NRDC states that the National Action Plan for Energy Efficiency Report ("NAPEE Report") was written in 2008 at a time before DRIPE gained mainstream acceptance, well before most states that currently recognize DRIPE had included it in their cost-effectiveness screening, and predates all the research cited by NRDC that establishes DRIPE as a best practice. In NRDC's view, the NAPEE Report is outdated and no longer reflects national consensus regarding the appropriate cost-effectiveness screening inputs. (NRDC Reply at 16-17)

NRDC regards as disingenuous ComEd's suggestion that the Illinois' TRC should conform to the inputs identified in the NAPEE Report when ComEd, to date, has refused to include NEBs as part of its cost-effectiveness screening. NRDC insists NEB's are explicitly identified as a societal benefit and an appropriate TRC input by the NAPEE Report. (NRDC Reply at 17)

NRDC considers ComEd's contention that DRIPE would be a "dramatic adjustment" to current screening practices that could "artificially" result in "highly uneconomic" programs becoming cost-effective hyperbole. NRDC asserts the adjustment would not be "dramatic." NRDC says the impact on efficiency measures with a 10 year life would be the equivalent to about a 35% increase in avoided electric energy costs. NRDC says it has estimated that avoided energy costs represent, on average, a little less than two-thirds of the total value of ComEd's efficiency program's energy savings; the other one-third represents the avoided generating capacity and avoided T&D costs. NRDC believes DRIPE would increase the estimated benefits of efficiency by an average of approximately 20% to 25%. NRDC asserts that while non-trivial and enough to render Ameren's three "near miss" programs cost-effective, regarding DRIPE as a "dramatic" adjustment is a dramatic overstatement. (NRDC Reply at 18)

NRDC believes there is nothing "artificial" about DRIPE benefits. NRDC contends DRIPE causes actual reductions in energy prices and represents actual money saved by all Illinois electricity consumers. NRDC claims ComEd, in stating that DRIPE could result in "highly uneconomic" programs becoming cost-effective confuses the evil to be avoided. NRDC asserts that because DRIPE's benefits are real, excluding DRIPE benefits from cost-effectiveness screening will result in an uneconomic investment in the supply of electricity. (NRDC Reply at 18)

NRDC agrees, its advancement of DRIPE, as well as NEBs and marginal line losses, are "results oriented." NRDC argues it is not cynically exploiting these technical concepts to force feed preferred energy efficiency programs irrespective of costs. NRDC says ensuring that Illinois residents are not deprived of beneficial energy

efficiency programs by utilities that omit well-established, technical concepts is one such position or "result" NRDC will continue pursue before the Commission and elsewhere. NRDC says it has been raising the issues of marginal line losses, DRIPE, or NEBs over the course of many years, both before the SAG and in private discussions with utilities. In NRDC's view, it is unfair to accuse NRDC of only now co-opting these issues to advance a self-serving "result." (NRDC Reply at 19)

NRDC claims it is not suggesting that improvements to cost-effectiveness screening should only be applied to Ameren's "near miss" programs. NRDC asserts that these improvements in the form of marginal line losses, NEBs, and DRIPE should be applied to all energy efficiency programs, whether Sections 8-103 or Section 111.5B, of both utilities. Being mindful of time limitations, NRDC says it did not wish to elevate process over outcome by requiring both ComEd and Ameren to re-screen every Section 16-111.5B programs regardless of whether it would affect the Plan. NRDC claims it has attempted to advocate for practicality in its requests. (NRDC Reply at 19)

Ameren regards NRDC's critique of the manner in which it conducted its review of third-party bids as "unfair and unwarranted." NRDC says it is not its position that in collaborating with stakeholders, Ameren be bound by the terms of stakeholder feedback or assessments. NRDC understands that Ameren would maintain absolute control over the content of Ameren's review and submission to the IPA regarding third-party bids. NRDC requests that Ameren be "expressly encouraged" to directly communicate with interested stakeholders regarding its third-party bids reasonably in advance of the submission deadline, on multiple occasions, and for a reasonable period of time in an earnest attempt to resolve points of dispute. (NRDC Reply at 20-21)

Ameren regards as "unfounded" NRDC's purported request that the Commission order the IPA to "undertake yet another review of Ameren's TRC calculation and then order a modification, presumably so that certain programs "pass the test." NRDC says the IPA's review of Ameren's cost-effectiveness screening was more a confirmation that past practices were used than a "critical analysis." NRDC also says the IPA stated that it agrees that DRIPE, non-energy benefits, and marginal line losses meet the definition of "other quantifiable societal benefits" under the IPA Act. NRDC asserts the IPA has not complied with the mandate in Section 16-111.5B(a)(4) of the PUA. NRDC argues that if it had, Ameren would have been required by the IPA to include marginal line losses and DRIPE and the three "near miss" programs would likely be part of the Plan. (NRDC Reply at 21)

NRDC opposes Staff's proposal to significantly modify the Proposed Order to reflect its views. NRDC claims Staff provides no new technical literature, expert affidavits, or legal authority. NRDC believes the degree of specificity requested by Staff limiting the manner by which NEBs can be recognized is ill-conceived. NRDC says there is no statutory requirement that the TRC include only those benefits "that have been quantified through a defensible study and that are applicable to different program types to which they are applied." According to NRDC, the PUA solely requires that the benefits are "quantifiable." (NRDC RBOE at 1-4)

NRDC claims Staff has provided no basis for supposing that the NEBs for these programs cannot be calculated or, if calculated, would be less than the 10% assumed by Ameren. In NRDC's view, Staff has no basis concluding anything about the actual value of the NEBs of these three near miss programs or that Ameren has overstated as opposed to understated those actual benefits. (NRDC RBOE at 4-5)

3. The IPA's Position

Ameren suggests that the workshop on the total resource cost test be held under the auspices of the SAG rather than being led by Staff. The IPA states given the SAG's long and successful track record on energy efficiency issues related to the Section 8-103 programs, the IPA is supportive of this suggestion. (IPA Response at 23)

NRDC first objects that "[t]he Plan should expressly encourage utilities to develop requests for proposals with input from and collaboration with interested stakeholders throughout the process." On reflection, the IPA agrees with NRDC that the most warranted outcome is likely an express requirement of collaboration. (IPA Response at 23)

NRDC's second objection is that "[t]he IPA should amend the Plan accordingly after adjusting the calculations for Ameren's three programs with a TRC over 0.9 but less than 1.0 so that DRIPE, marginal line losses, and a non-energy benefits adder are included and any non-essential administrative cost adders are excluded." Under Section 16-111.5B(a)(4), the IPA's obligation for determining the cost-effectiveness of individual energy efficiency programs reads as follows:

> The Illinois Power Agency shall include in the procurement plan . . . energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal included in the annual solicitation process and assessment submitted pursuant to paragraph (3) of this subsection (a).

The IPA believes this raises two questions: whether the IPA should have departed (or the Commission should depart) from the TRC methodology employed in the review of programs under Section 8-103 of the IPA Act; and, if so, whether the inclusion of DRIPE and other benefits identified by NRDC would be a warranted departure. (IPA Response at 23-24)

As to the first question, the IPA says its review of these programs did not "merely defer" to Ameren's TRC results. The IPA claims it conducted a critical analysis of the inputs into the Ameren TRC analysis and raised questions about consistency with the utility's evaluation of programs under Section 8-103 of the PUA. Upon receiving confirmation from Ameren that its Section 16-111.5B TRC analysis utilized the same model and inputs as evaluation of its Section 8-103 programs, and without identifying

other errors or problems through its analysis, the IPA determined which programs to include. (IPA Response at 24)

The IPA believes any cost-effectiveness determination made by the IPA should be consistent with direction provided by Section 16-111.5B of the PUA, which calls for the utilities to develop requests for proposals consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of the PUA. The IPA says Section 16-111.5B further requires that the term "cost-effective" have the meaning set forth in subsection (a) of Section 8-103 of the PUA. The IPA states this cost-effectiveness screen is used to identify new or expanded cost-effective energy efficiency programs that are incremental to those included in energy efficiency and demand response plans approved by the Commission pursuant to Section 8-103 of the PUA. (IPA Response at 24)

The IPA notes Ameren identified two additional adjustments: 1) an emerging technologies set-aside under Section 8-103, and 2) program level assignment of administration, evaluation measurement & verification, education, and marketing costs otherwise assigned at the portfolio level for Section 8-103 programs. The IPA believes these adjustments were warranted. (IPA Response at 24)

The IPA indicates it appreciates that Section 16-111.5B(a)(4) in isolation could be understood to demand a more rigorous evaluation, even justifying the use of evaluative criteria separate from criteria used to evaluate programs under Section 8-103. By conducting a critical analysis of TRC inputs while not disturbing the utilities' established TRC methodologies, the IPA believes it properly balanced the need for consistency between Section 16-111.5B and Section 8-103 with the requirement that it shall include in the procurement plan programs and measures it determines to be cost-effective. The IPA believes that it did not fail to meet its statutory obligation. (IPA Response at 25)

On the second question, the IPA believes NRDC's Objections raise a number of interesting points regarding the inclusion of DRIPE, marginal line losses, non-energy benefits, and administrative costs as evaluative criteria in a TRC analysis. The IPA agrees that those factors likely meet the definition of "other quantifiable societal benefits" in the IPA Act that may have been overlooked in past analyses. While the IPA takes no position on whether consideration of NRDC's recommended criteria is required for the Commission to determine whether included programs and measures "fully capture the potential for all achievable cost-effective savings," the IPA cautions against rushing into the adoption of any new criteria. The IPA suggests such changes may be more effectively implemented by broader consensus developed through the state's well-established SAG process, providing more ample opportunities for feedback. (IPA Response at 25)

Staff objects to the IPA's justification for the recommendations as to which Ameren behavioral program should be included in the plan. Staff's objection has several parts: first, a request to include in the Plan an alternative expression of the total

resources cost test expressed as the difference between costs and benefits rather than as a ratio; second, a discussion of the experience of energy savings and cost effectiveness for home energy reports for Ameren and elsewhere in Illinois; and third, a discussion of whether the two Ameren behavioral programs are "competing" or "duplicative."

The IPA does not believe that changes to its Plan are warranted in response to Staff's objections. The IPA states that as outlined in the 2014 Procurement Plan and addressed in Docket No. 13-0546 filings, pragmatic decisions must be made when there are "duplicative" bids. The IPA says information will never be perfect, but a determination must be made. The IPA does not oppose selection of the Behavioral Energy Efficiency Program, but believes that the balance of relevant evidence supports including Home Energy Reports. (IPA Response at 26)

In its Objections, Staff proposes that "the Plan should present the TRC results for the programs on a net present value basis, not solely on the basis of TRC benefit-cost ratios." The IPA believes that this is unnecessary. The IPA says Section 1-10 of the IPA Act provides that for the TRC, the benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. The IPA believes this is sufficient to understand cost-effectiveness. (IPA Response at 26)

Staff objects that "it appears the IPA is requesting the Commission approve a vendor's program that provides significantly fewer net benefits than another vendor's program on the basis that the vendor has experience operating in Illinois and thus the savings estimates proposed by that vendor are more reliable," and wishes to use this added information to underscore that point. The IPA says both programs are "cost-effective" and cost-effectiveness is the baseline for consideration for inclusion in the Plan. The IPA states both programs qualify, and are thus included. In the IPA's view, adding the additional column as proposed by Staff does not materially advance the consideration of "duplicative" programs. (IPA Response at 26-27)

The IPA believes that uncertainty regarding the potential per-household savings of each program makes relative comparisons of the TRC not dispositive. Instead, it is the screen for "duplicative" programs that leads the IPA to recommend inclusion of one program over the other, in particular, a difference in "likelihood of program success." (IPA Response at 27)

Staff raises concern that not adopting the non-incumbent program with the higher TRC "will have negative implications for future utility annual solicitation processes for third-party energy efficiency providers," as "less competitive pricing may be incentivized for incumbent energy efficiency providers and potentially a reduced number of bids." The IPA suggests adopting a non-incumbent program with a higher TRC but lower likelihood of program success could also create a perverse incentive, potential manipulation of estimated savings values by weaker programs to win analyses against stronger "duplicative" programs. The IPA believes any choice between "duplicative"

programs viewed as a governing precedent may negatively impact future bidder behavior and introduce unwanted new incentives. (IPA Response at 27)

In the IPA's view, Staff's concern is a fair concern, and the IPA wishes to be clear that these analyses must be made on a case by case basis. The IPA believes incumbent providers should not presume that they will inherently be given an advantage. Instead, the IPA says its recommendation between these programs is based on a qualitative consideration of multiple factors. (IPA Response at 27)

The IPA states Staff provides an extensive discussion of the evaluated results of Home Energy Reports in other utility jurisdictions in Illinois and variation in results. The IPA believes this discussion underscores the point that there is indeed uncertainty related to the impacts of behavioral energy efficiency programs. In the IPA's view, absent a deemed value in the Technical Reference Manual, cost effectiveness consideration of the programs begins with the values provided by each vendor. (IPA Response at 28)

Staff cites an evaluation of Home Energy Reports from Peoples Gas where evaluated therm savings were higher (14.21 therms per household) than the value used by the Home Energy Reports vendor in their bid (approximately 7 therms). According to the IPA, that higher evaluated savings value for the Home Energy Reports vendor is consistent with the therm savings estimate provided by the Behavioral Energy Efficiency program vendor. The IPA says if that higher therm savings estimate were used in the Home Energy Reports bid, the difference in TRCs between the programs would be negligible. (IPA Response at 28)

While there are differences in the kWh savings used by the two vendors, the IPA asserts the two proposals' difference in values is mostly a function of the above-referenced therms per household savings estimates supplied by each vendor. The IPA claims this disconnect between vendor-supplied estimates and evaluated therm savings, along with the inherent uncertainty surrounding vendor-supplied values, underscores the weakness of choosing between the two programs on the basis of their TRCs when the input values are not based on the Technical Reference Manual. (IPA Response at 28)

Staff's final objection relates to whether the programs are "competing" or "duplicative." The IPA states as detailed in the Plan, "competing" programs can successfully coexist in the market while "duplicative" programs cannot, and therefore a selection between "duplicative" programs must be made. The IPA says it applied the seven criteria for determining "duplicative" programs and determined that the two programs are indeed "duplicative." The IPA believes the outcome should be to subjectively determine which program to approve, and not to attempt to engage in post-bid substantial modifications in program scope. (IPA Response at 28-29)

The IPA suggests legacy participants appear to be a fundamental part of the Home Energy Reports proposal. If this were the only problematic criterion, the IPA

would not oppose an adjustment in target size to allow both programs to coexist, as Staff suggests. The IPA believes there are practical implementation issues (such as how Ameren's website would direct customers to the correct vendor's website, and coordination with Section 8-104 gas energy efficiency funding) that may make this infeasible. The IPA contends it is also likely that economies of scale would be lost if each program is made smaller, thus eroding the net benefits of the entire endeavor. In the IPA's view, simply refining targeted households is a far cry from the significant program changes that would be needed to allow competing behavioral efficiency programs to run in parallel. (IPA Response at 29)

Staff suggests various ways that Ameren and the IPA could work with vendors to refine and coordinate bid responses. The IPA says it first saw vendor bid responses as part of Ameren's July 15, 2014 filing, but is not opposed to a consideration of a more active and earlier role in the bid screening and evaluation process in future years. (IPA Response at 29)

ComEd and Staff both express concerns regarding NRDC's proposal to add DRIPE, and to alter how marginal line losses, administrative costs, and non-energy benefits are used in the TRC calculation. Ameren expressed its disagreement with NRDC regarding the stakeholder input process and the level to which the IPA reviewed the TRC calculations, while ELPC shared NRDC's concerns.

The IPA says this proceeding is to approve the IPA's 2015 Procurement Plan, including the incremental energy efficiency proposals pursuant to Section 16-111.5B. The IPA believes that a proceeding of this type may not be the appropriate venue for initial consideration of fundamental policy issues such as the inputs into the TRC. The IPA claims this is acutely so when the widely divergent views of ComEd, NRDC, and Staff are considered. The IPA says these parties provide diametrically opposed viewpoints as to the appropriateness of making changes to the TRC calculations, perhaps inflected due to the adversarial nature of litigation. (IPA Reply at 12-13)

Whatever the merits of proposed TRC changes, for the instant proceeding, the IPA maintains that the calculations provided by Ameren, and carefully reviewed by the IPA, are consistent with current practice and standards as have been applied to Section 8-103 programs and that the IPA met its statutory duties under Section 16-111.5B of the PUA. (IPA Reply at 13)

The IPA believes the best path forward is to conduct workshops that would allow the proper time and process for considering if any of the proposed TRC changes should be made. NRDC is doubtful that a workshop setting, whether at the SAG, or held by Commission Staff, is the proper forum to resolve differences regarding the appropriate TRC inputs. While the IPA is sympathetic to NRDC and ELPC's desire for immediate resolution, the IPA believes the record in this proceeding is simply too limited relative to what may be accomplished through more thorough and deliberate consideration. If a workshop does not suffice, the IPA suggests another approach could be for the Commission to open a formal investigation of the TRC methodology, but the IPA does

not believe that a formal investigation would be a faster or more efficient way to proceed, and thus continues to recommend a workshop process. (IPA Reply at 13)

In Objections related to Ameren's behavioral programs, Staff proposed a novel manner of expressing the TRC as the difference between costs and benefits rather than as a ratio. ComEd in its Response disagrees with that proposal, and ComEd's concerns mirror those articulated by the IPA in its Response. The IPA continues to recommend that the Commission reject Staff's proposal. (IPA Reply at 13)

The IPA says Ameren has clarified that the budgets associated with behavior modification program proposals (Home Energy Reports/Behavioral Energy Efficiency) each include $2,224,375 from its approved Section 8-104 gas energy efficiency plan. Additionally, in response to Staff Data Request JHM 3.01, the IPA says Ameren indicated that the correct TRC for the Small Business Direct Install program should be 1.03. Based upon these clarifications, the IPA recommends that Table 7-2 of the Plan be modified as follows:

Program	Net Savings		Total Utility Cost	TRC
	Program Year 1	Program Year 2		
Moderate Income Kits	1,567	1,567	$1,666,737	1.22
Residential Lighting	48,190	53,556	$21,637,240	1.64
Rural Efficiency Kit Distribution	7,876	7,876	$2,214,245	3.09
Multi-Family Major Measures	38,943	38,943	$32,820,805	1.57
Home Energy Reports [1]	40,013	40,013	$4,555,440	1.12
Behavioral Energy Efficiency [2]	47,111	47,111	$4,488,750	1.59
Small Business Direct Install	9,588	9,788	$7,174,723	1.03
Small Business Refrigeration	17,947	17,947	$7,571,125	1.09
Demand-Controlled Ventilation	5,318	-	$1,146,840	1.20

1: The electric portion included in this Plan and to be recovered through Rider EDR is $2,331,065.
2: The electric portion included in this Plan and to be recovered through Rider EDR is $2,264,375.

The IPA states that on exceptions, NRDC proposes Ameren programs with TRC results between 0.9 and 1.0 may be summarily included in the IPA's approved Plan consistent with requested changes to TRC test review methodology. The IPA disagrees that these programs can be included without a new TRC review. Should the Commission approve changes in the TRC methodology employed for the review of programs under Section 16-111.5B, the IPA believes the PUA requires such programs must be reviewed for cost-effectiveness consistent with the approved TRC changes. The IPA contends that failure to do so would be inconsistent with Section 16-111.5B's requirement that programs and measures be "cost-effective" and could set a troubling precedent for future program approval. The IPA does believe post-Order review and approval may be feasible, but implementation requires detailed procedural guidance from the Commission with a defined process and timeline for cost-effectiveness review and program approval. (IPA RBOE at 6-7)

The IPA disagrees with Staff that the proposed inclusion of DRIPE within a TRC analysis should be rejected as inconsistent with the law and sound economic policy. Given the competing analyses and approaches employed by various other states, the IPA believes that it is far from clear in the record that DRIPE is not a "societal benefit" fit for inclusion in a total resource cost analysis and opposes Staff's proposed language making this determination through this proceeding. The IPA believes a more prudent approach may be to leave this issue open for further analysis and review. (IPA RBOE at 7)

Staff requests the inclusion of program "net benefits" for all proposed Section 16-111.5B programs in future years' plan filings. The IPA finds Staff's argument somewhat confusing. The IPA says Staff's stated rationale for including an additional column on "net benefits" appears to hinge on the role of this information in assisting the Commission with choosing between "duplicative" programs. The IPA asserts that the vast majority of programs are not "duplicative." For those that are, the IPA says "duplicative" determinations are usually made between existing programs under Section 8-103 and a proposed program under Section 16-111.5B. In such cases, should a proposed Section 16-111.5B program be determined to be "duplicative" and not "competitive," the IPA says it would not be recommended for approval and no comparison of program merits would be made (as the Section 8-103 program would have already been approved in a separate proceeding, and the proposed Section 16-111.5B program would be deemed "duplicative" and thus incompatible).

Staff seeks adoption of its preferred Ameren behavioral program through selection of the Behavioral Energy Efficiency vendor, rather than the Home Energy Reports vendor recommended by both Ameren and the IPA. The IPA disagrees with Staff that the Proposed Order does not specify which behavioral program is approved. The IPA notes the Proposed Order "rejects Staff's proposed modifications to the Plan." In so doing, the IPA says it adopts the Plan's recommendation, sufficient specification is made, and further modification is unnecessary. (IPA RBOE at 9-10)

4. Staff's Position

Staff believes in order to provide a meaningful comparison in TRC results for competing or duplicative programs, the Plan should present the TRC results for the programs on a net present value basis, not solely on the basis of TRC benefit-cost ratios. Staff says a comparison of TRC benefit-cost ratios is only one item of relevance to decisions about which of two competing or duplicative programs should be pursued. Staff recommends the Commission order the utilities to provide such information in their energy efficiency assessments submitted to the IPA and should further order the IPA to present such information in future procurement plans. (Staff Objections at 15)

It appears to Staff the IPA is requesting the Commission approve a vendor's program for Ameren that provides significantly fewer net benefits than another vendor's program on the basis that the vendor has experience operating in Illinois and thus the savings estimates proposed by that vendor are more reliable. Staff says the IPA provides no evidence showing that the other vendor's (Behavioral Energy Efficiency) savings estimates should be deemed unreliable. If the IPA disagrees with the other vendor's (Behavioral Energy Efficiency) savings estimates, then Staff claims the IPA should revise the estimates, provide support for the savings estimates it recommends,

and recalculate the TRC for the vendor's (Behavioral Energy Efficiency) program to reflect these beliefs and report the revised TRC results (TRC benefit cost ratios and net present value of TRC benefits) in Table 7-2 of its Plan. Staff asserts the IPA should demonstrate that the behavioral program it is supporting provides greater net benefits than the one it is rejecting as duplicative. According to Staff, the TRC results in the Proposed Plan indicate the IPA supports a behavioral program that provides significantly fewer net benefits (~$1,874,071) than the one it is rejecting as duplicative. (Staff Objections at 16-17)

Staff is concerned that adoption of the IPA's request on this issue will have negative implications for future utility annual solicitation processes for third-party energy efficiency providers as required by Section 16-111.5B of the PUA. Staff suggests less competitive pricing may be incentivized for incumbent energy efficiency providers and potentially a reduced number of bids. Staff asserts this will ultimately increase the cost to ratepayers of achieving savings from such programs, eroding the net benefits to ratepayers that otherwise should exist with competitively priced bids, and ultimately undermining the intent to achieve all cost-effective savings outlined in Section 16-111.5B. (Staff Objections at 17)

The Proposed Plan states the IPA believes the Home Energy Reports program team's experience to date in Ameren's service territory and established working relationship with the utility makes it slightly more likely to deliver increased savings to customers and maximize the impact of Section 16-111.5B funds. Staff complains the IPA fails to describe what the "experience to date" has been for the Home Energy Report program team operating in the Ameren service territory. It is unclear to Staff how the Commission is supposed to make an informed decision on this issue when no information is provided concerning the evaluation results of this program from experience in the Ameren service territory. (Staff Objections at 17)

Staff asserts the Home Energy Report program was not cost-effective during program year 3 ("PY3"), producing negative net benefits in the amount of $174,369 (TRC=0.79). (Staff Objections at 18)

Staff states that the actual *ex post* evaluated TRC results for ComEd's Home Energy Report program have shown negative net benefits were produced during certain program years: in PY3, the Home Energy Report program produced negative net benefits in the amount of $1,319,000 (TRC=0.39); and in PY4, the Home Energy Report program produced negative net benefits in the amount of $144,000 (TRC=0.95). Staff notes the IPA provides no ex post TRC results for either vendors' programs when it makes its recommendation that the Commission should approve the Home Energy Reports program. (Staff Objections at 18)

According to Staff, the IPA appears to argue it has more confidence in the savings per household identified in the Home Energy Reports TRC analysis than that identified in the Behavioral Energy Efficiency TRC analysis. Staff takes issue with this finding based on the past experience of the Home Energy Reports program in the

Ameren service territory. Staff states the savings per household has varied dramatically across program years, across customer groups, varied by original baseline usage, and likely by demographic characteristics, and Ameren's evaluators' note that savings assumptions for future years should be refined based upon the baseline consumption of the targeted group as well as number of years the customers have been in the program. (Staff Objections at 19-20)

Staff says the IPA states the Home Energy Reports proposal is for 14% more households, yet the IPA does not distinguish between legacy households and new households. In Staff's view, this is an important distinction because there should be virtually no start-up costs expected for the Home Energy Reports vendor for legacy households, and thus one would expect lower overall costs to the extent a larger percent of the households are legacy, all else the same. It appears to Staff that the Home Energy Reports program plans to target 200,000 legacy households, and only 60,000 new households, and the Behavioral Energy Efficiency program plans to target 90,000 legacy households and 138,769 new households, which is more than double the amount of new households the Home Energy Reports vendor plans to target. Staff believes this is an important distinction because, from a theoretical standpoint and the law of diminishing returns, the legacy customers' savings per households could be expected to level out over the next couple of years while new households have a significant amount of savings to be had. (Staff Reply at 20-21)

The IPA states that the Behavioral Energy Efficiency program bid estimates electric savings per household that are over 30% higher than the Home Energy Reports and gas savings that are nearly 100% higher. According to Staff, the Behavioral Energy Efficiency program vendor appears to assume 193 kWh savings per household and 13.53 therm savings per household. Staff says, based on the recent Peoples Gas evaluation of its Home Energy Reports program, the actual evaluation results of the Peoples Gas service territory in the first year of Home Energy Reports program operation achieved 14.09 adjusted therms per evaluated household (or 14.21 therms per household), which is greater than the assumed 13.53 therm savings per household for the Behavioral Energy Efficiency Program vendor that the IPA takes issue with. In reviewing the Ameren electric energy savings results, State notes the results range widely from 38.12 adjusted kWh savings per household (expansion group 2 in PY4 evaluation) to a high of 233.5 adjusted kWh savings per household (expansion group 1 in PY5 evaluation). Given the Behavioral Energy Efficiency program's assumed 193 kWh is within the evaluated range for Ameren's program, Staff does not believe it is reasonable for the IPA to adjust the savings with no evidence from that vendor's evaluated programs, especially given the different proportions of legacy versus treatment households the two behavioral vendors intend to target. Staff asserts any such adjustments to assumed savings per household should be accompanied by an explanation of both how the baseline consumption of the behavioral vendor's targeted group of customers and the number of years the customers have been in the program is taken into account in making the savings adjustments. In Staff's view, the IPA does not provide a sound basis to discount the Behavioral Energy Efficiency program vendors assumed savings. (Staff Objections at 21-22)

The IPA also notes that the Home Energy Reports program has been subject to more than 20 evaluations across the country. Staff claims the IPA should provide a summary of the evaluation results in terms of savings per household (and any other important factors about the customer groups and service territories) from the more than 20 evaluations available such that the variance in savings achievement for the Home Energy Reports program can actually be analyzed and compared with that assumed in the Behavioral Energy Efficiency analysis. Staff says the IPA and Ameren should request from the Behavioral Energy Efficiency program vendor that past evaluation results be produced for review in this proceeding. (Staff Objections at 22)

Staff believes the IPA and Ameren should further elaborate on why only one behavioral program can be adopted or provide the TRC results from scenarios that could be workable for both vendors to co-exist. The Proposed Plan outlines a seven-factor inquiry to be employed in making determinations concerning duplicative or competing. Staff recommends the Commission explicitly address each of these factors when it makes its duplicative determination in relation to the two behavioral programs and Ameren and the IPA should address each of these factors in their comments. (Staff Objections at 22-23)

Staff says that the claim that "the total number of residential customers eligible for the program could not support two behavior modification programs" holds true if the number of legacy households targeted per vendor is fixed at the levels currently contained in Appendix B. In making this determination, Staff considered that there are not enough previously treated households to allow for 200,000 legacy households to continue under the Home Energy Reports Program and another 90,000 legacy households to continue under the Behavioral Energy Efficiency Program because there exist only 236,789 electric legacy households receiving the reports as of quarter 3 of PY6. Staff says the vendor program templates indicate an apparent willingness of the vendors to work with Ameren to help refine the targeted households based on a variety of factors. (Staff Objections at 23-24)

Staff says the assertion that "running multiple programs would lead to significant confusion of residential customers" holds true only to the extent that each program sends reports to some of the exact same households, as each vendor coincidentally proposed in the initial submission. It is conceivable that a residential customer, upon receipt of two separate reports within the same month, may be somewhat confused. Staff does not recommend this approach. Staff believes coordination could occur whereby each vendor sends the reports to a separate set of households. (Staff Objections at 24)

Staff reports ComEd identified 9 of its 11 programs as "competing" but not "duplicative," meaning appropriate delivery conditions could be structured and customers could be targeted in a way to ensure that consumers benefit from multiple delivery channels, and thus the presence of a similar program would not be grounds for exclusion. Staff believes Ameren should do the same as ComEd in this regard and

analyze whether appropriate delivery conditions could be structured and customers could be targeted in a way to ensure that consumers benefit from multiple delivery channels. Staff is not convinced that the behavioral programs proposed for the Ameren service territory cannot be structured in a way to avoid customer overlap and confusion. Staff claims the Home Energy Reports Program description already envisions a target marketing approach to determine where to deploy the proposed program. (Staff Objections at 24-25)

Staff argues that if coordination occurred to avoid targeting the same households as the other vendor's program then both may be able to co-exist and be able to achieve greater cost-effective savings. Staff says the Behavioral Energy Efficiency Program description indicates the vendor is willing to work with Ameren to adjust the number of households targeted (i.e., treated) through their proposed program: "As with treatment group 'A', Tendril will work with Ameren Illinois to further define this segment" and will further qualify the treatment numbers. Given the apparent willingness of the vendors to work with Ameren to help refine the targeted households, Staff asserts the IPA and Ameren should work with the two behavioral program vendors to see if they are willing to develop several workable scenarios where both vendors could co-exist and such that they could be presented in comments for the Commission's consideration in order to ensure the programs "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as set forth in Section 16-111.5B. (Staff Objections at 25-26)

It seems feasible to Staff to coordinate the two behavioral programs (in lieu of choosing one vendor over another) to avoid customer confusion (i.e., by targeting different households), and the IPA and Ameren should work with the two vendors to see if they are interested in developing several workable scenarios where both programs co-exist and provide greater net benefits to customers than if only one existed. Staff says the IPA and Ameren should work with the behavioral program vendors to disaggregate program components so as to allow as direct an "apples to apples" comparison of costs, savings, and net benefits as possible. In Staff's view, the behavioral programs should at least be broken out such that the TRC results can be reviewed in the event the vendors target only legacy households, and in the event the vendors target only new households (including those households that have not received reports in two years). Staff says the TRC benefit-cost ratios, the net present value of TRC benefits, costs, start-up costs, and savings should be provided for the various scenarios and the two program components. (Staff Objections at 26)

Staff recommends the Commission require, in future situations such as this, that the IPA and the utility work with the potentially duplicative/competitive vendors to disaggregate program components so as to allow as direct an "apples to apples" comparison of costs, savings, and net benefits as possible. (Staff Objections at 26)

Staff disagrees with the statement that "running multiple programs would lead to significant confusion of residential customers, which would hamper the adoption of the Behavioral Modification program, rather than increase it." Staff says these behavioral programs are opt-out programs. Staff asserts if each of the programs target different

households with the reports then there will not be significant confusion of residential customers, and indeed adoption (i.e., customers not opting out of the program) would likely increase overall because more households would be receiving the reports. (Staff Objections at 27)

Ameren states that the post procurement plan proceeding TRC workshops recommended by the IPA should be conducted through the Illinois Energy Efficiency SAG process as this "would allow all interested parties, including other utilities in Illinois not participating in this docket, to participate in addressing the issue."

Staff has no objection to Ameren's proposed language change to the Proposed Plan that would shift responsibility from Staff to the SAG, subject to the addition of certain clarifying language. As an initial matter and as a point of clarification, Staff says meeting notices and other information concerning the Section 16-111.5B energy efficiency workshops Staff held following the Commission's Order in Docket No. 13-0546 were distributed to the entire SAG e-mail distribution list and were posted on the Commission's website and these workshops allowed for all interested parties, including those not involved with the procurement plan dockets, to actively participate in the workshops. For clarity of the record, regardless of whether Staff or the SAG hosts the TRC workshops, Staff states all interested parties, including other utilities in Illinois not participating in this docket, would be able to participate in addressing the TRC issues. (Staff Response at 16)

Staff has no objection to Ameren's proposed language change to the IPA Plan that would shift responsibility from Staff to the SAG. Staff states that in the Commission's Orders in the energy efficiency plan dockets (i.e., Docket Nos. 13-0495, 13-0498, 13-0499, 13-0549, 13-0550) that were entered earlier this year, the Commission tasked the SAG with developing an Illinois energy efficiency policy manual that could address consistency for energy efficiency program evaluation issues statewide, such as consistent TRC approaches across the utilities. Staff believes it is conceivable that synergies may exist if SAG coordinated any TRC workshops required by this docket with the Illinois energy efficiency policy manual development process as it pertains to consistent TRC approaches to be used by the various program administrators. (Staff Response at 17)

Staff states that given the lack of progress that has been made thus far in the SAG on the Illinois energy efficiency policy manual due in part to the SAG being "shut down" for over two months now, Staff requests certain additional clarifications be added to Ameren's proposed modifications to the Proposed Plan's language in order to clarify certain responsibilities. Staff provides specific language it believes the Commission should adopt to page 80 of the Proposed Plan. (Staff Response at 17-18)

Staff indicates it takes no position at this time on NRDC's proposed changes on the means by which marginal line losses are included in the TRC and believes that any benefits and costs should be accurately determined for inclusion in TRC calculations. Staff believes the marginal line loss issue should be addressed at the TRC workshops

proposed by the IPA for spring 2015, which is consistent with the IPA's proposal in its Plan. Staff says the Commission need not make a determination on the marginal line loss issue until after the TRC workshops are complete. (Staff Response at 18-19)

The accurate inclusion of costs includes costs that Staff understands NRDC to characterize as "non-essential administrative costs." Staff says these costs include items such as the cost to evaluate a program and the cost to administer the contracts associated with a program. Staff states that within the energy efficiency portfolio administered as a requirement of Section 8-103 of the PUA, these types of costs are excluded from program-level TRC analysis but are instead included within a portfolio-level TRC analysis. (Staff Response at 19)

In the context of the Section 16-111.5B EE programs, Staff asserts it is more appropriate to include these types of costs within the program-level TRC analysis. Staff says there is not a portfolio in Section 16-111.5B in the same context as there is under Section 8-103 of the PUA. Staff states that Section 8-103(f)(5) requires the overall portfolio to be cost-effective under the TRC test as a component of Commission approval of the EE plan, whereas Section 16-111.5B(a)(4)-(5) requires each program to be cost-effective under the TRC test as a component of Commission approval of the EE programs in the Procurement Plan. Under the IPA requirements, Staff claims funds are not reallocated from one program to another in order to acquire a mandated level of savings. Instead, each program is a stand-alone program that operates independently from the other programs under Section 16-111.5B. (Staff Response at 19)

Staff argues that a consequence of this difference between the Section 8-103 and Section 16-111.5B EE programs is that there is not a portfolio-level cost-effectiveness analysis to be conducted for the Section 16-111.5B programs. Staff believes exclusion of administrative costs as a cost in the TRC analysis as proposed by NRDC is inappropriate and inconsistent with the definition of the TRC test found in Section 1-10 of the IPA Act. Staff recommends that the Commission reject NRDC's proposal to remove real administrative costs from Ameren's TRC analysis of the vendors' programs bid under Section 16-111.5B as such a proposal is inconsistent with the statutory requirements of Section 16-111.5B that the programs must be cost-effective under the TRC test for them to be included in the IPA Plan. (Staff Response at 19-20)

Staff also believes the Commission should reject the inclusion of DRIPE that are mentioned in the NRDC's second objection. Staff suggests the NRDC argument for inclusion of DRIPE seems to be that reducing the demand for electricity causes price reductions in the wholesale market and that these price reductions amount to a benefit to consumers that should be included within the TRC analysis for programs. Staff believes that the inclusion of DRIPE as a societal benefit is inappropriate and inconsistent with the definition of the TRC test found in Section 1-10 of the IPA Act. Staff also claims that should the Commission determine that DRIPE is a worthwhile benefit to include, there are multiple problems with the analysis performed by the NRDC

and presented within its comments and referenced within its Objections. (Staff Response at 20-21)

Staff states that from a customer's perspective, a reduction in price is a benefit. If a customer pays $1 less for a product or service without altering the quantity of the product or service used, Staff says that customer has additional money equal to $1 times the number of units of the item that are purchased to use as desired. Staff believes referring to this as a societal benefit is incomplete as customers are only one type of economic agent in a society. Staff claims there is also the effect of the lower price on producers. In this case, Staff says each unit sold provides $1 less revenue to a producer, without any corresponding decrease in production costs, and therefore represents a loss from the perspective of the producer. According to Staff, the result is that on net, society neither benefits nor loses from the lower electric price. From a societal perspective, Staff argues DRIPE represent nothing more than a transfer of wealth towards customers and away from producers. Staff argues it is neither a societal benefit nor a societal cost. In economic parlance, Staff says DRIPE would be referred to as a "pecuniary externality," as opposed to a "real" or "technological" externality. Staff says pecuniary externalities are pervasive in markets. Staff asserts that unlike real externalities, pecuniary externalities have no impact on economic efficiency and provide no justification for government intervention on economic efficiency grounds. (Staff Response at 21)

According to Staff, the Vermont Public Service Board makes a persuasive economic argument against counting DRIPE in a TRC test. Staff also asserts that relying on much less cogent arguments, the Vermont board subsequently changed its position on DRIPE. (Staff Response at 21-22)

Staff also claims the price reductions associated with DRIPE is only temporary. Staff maintains that DRIPE not only represents a decrease in consumer bills, it also represents a decrease in revenue to producers, without any corresponding decrease in production costs. Staff asserts these are changes in "consumer surplus" and "producer surplus." Staff contends that in a regulated or competitive market for energy (where economic profits tend toward zero), producer surplus is used as a means of recovering at least some portion of fixed costs. Staff states that as producer surplus is reduced, something else must change. Staff argues that the decrease in energy prices (or an expectation of such decreases) leads to a decrease in profitability (or expected profitability), which leads to an increase in energy generating unit retirements and a decrease in investment in new energy generating units, both of which leads to an eventual increase in capacity prices and/or energy prices. (Staff Response at 22-23)

Staff suggests the particular DRIPE analysis provided by NRDC also appears to be oversimplified and logically flawed or incomplete. Thus, even if the Commission determines that DRIPE is a benefit that should be included in TRC analysis, which Staff believes the Commission should not, Staff believes the Commission should reject the numerical findings provided by NRDC in the memo attached to its Initial Comments. (Staff Response at 23)

Staff's indicates its review of the NRDC linear regression models leads it to conclude that the models are only measuring a correlation between locational marginal prices and load. In Staff's view, the models lack the sophistication to determine the direction of causality between LMPs and Load. Staff asserts it is very likely that there is feedback between prices and loads that would cause the benefits to be overstated. (Staff Response at 24)

According to Staff, the regression analysis appears to suffer from what is commonly referred to in the econometrics literature as an identification problem. Staff states such problems arise when supply and demand equations are estimated simultaneously without proper controls and/or corrections. Under such circumstances, when supply and demand curves have the same included and excluded variables, Staff says regressing price on quantity generates estimates that could be estimates of supply parameters, estimates of demand parameters, or, most likely, both. When an identification problem occurs, Staff contends regression results are not meaningful and often appear to be implausible. (Staff Response at 24)

According to Staff, DRIPE represents a deviation from the typical calculation of the TRC and the approach historically adopted by the Commission. Staff believes that consistent with the Commission's findings in the 2013 Procurement Plan, Docket No. 12-0544, the Commission should again find that "NRDC has not provided an adequate basis or rationale for deviating from the Commission's past practice" in the assessment of benefits to be included in the utilities' TRC analyses of the energy efficiency programs. (Staff Response at 24-25)

The NRDC Responses to Objections includes an attached report ("NRDC Report") in support of NEBs and continues to argue that NEBs, marginal line losses and DRIPE should be included as societal benefits. NRDC also maintains that future workshops are fruitless as these issues have persisted and instead supports the Commission deciding the issue now in this time-constrained procurement docket. The ELPC agrees with NRDC's proposal. Staff disagrees with both ELPC and NRDC that a decision must be made in this docket. Staff believes TRC workshops will not be fruitless if the Commission makes it clear these TRC issues will be resolved in a future docket after conclusion of the workshops. (Staff Reply at 11)

The IPA's Responses explain its TRC review process and disputes the notion that the IPA deferred to Ameren's TRC analysis. The IPA admits it deferred to ComEd's TRC analysis when it explains that the IPA never received ComEd's TRC calculation files for review as part of ComEd's energy efficiency assessment submittal pursuant to Section 16-111.5B of the PUA. The IPA did in fact receive some of Ameren's TRC calculation files with its energy efficiency assessment submittal pursuant to Section 16-111.5B and had an opportunity to review them. In Staff's view, it does not seem fair to criticize the IPA for failing to make adjustments to Ameren's TRC analysis when there are no formal Commission policies surrounding the appropriate TRC methodologies and approaches to use that the IPA could use as a basis to make such adjustments. Staff

notes the IPA's Responses further state that marginal line losses, DRIPE, and NEBs may be societal benefits that have been previously overlooked. The IPA concludes by cautioning the Commission not to rush to judgment on including NRDC's proposed societal benefits but to instead let further deliberations take place within the Illinois energy efficiency SAG process. (Staff Reply at 12)

Staff argued against the inclusion of DRIPE, took no position on marginal line losses or NEBs, and argued that the non-essential administrative cost argument made by NRDC was incorrect. After reading the parties' Responses to Objections, Staff continues to believe that DRIPE is not a societal benefit but is merely a transfer from suppliers to consumers. Staff now believes that NEBs as currently included in Ameren's TRC analysis may be inappropriate and that there is no justification at this time for increasing the 10% adder that Ameren included. (Staff Reply at 13)

Given NRDC's clarification of the derivation of the administrative cost amounts assumed in the TRC analyses, Staff believes that further analysis of the utilities' administrative cost assumptions compared to actual administrative expenses incurred for the Section 16-111.5B programs may be warranted. Staff also believes that in principle marginal line losses seem to be a more accurate approach than average line losses for measuring the benefits from avoided energy use; but Staff is concerned that the benefits of such a study may not outweigh the cost for Ameren to conduct such a study of marginal line losses and incorporate the results in future TRC analysis. Staff suggests the costs for Ameren to conduct a marginal line loss study can be discussed during the TRC workshops in order to ascertain whether such a study would be worthwhile. While NRDC claims that the utilities carefully ensure that participant costs are identified and properly included in the TRC, Staff notes that on the cost side of the TRC equation, no measure cost study has ever been conducted in Illinois in order to refine those critical cost assumptions impacting cost-effectiveness. To ensure fairness in the scrutiny of both sides of the TRC equation, Staff believes any workshop discussions about the value of Ameren performing a marginal line loss study should also be compared to the value of conducting a measure cost study for purposes of updating the default energy efficiency measure costs contained in the IL-TRM. Staff says the energy efficiency measure costs are generally used by all the Illinois utilities in performing their cost-effectiveness screening, and as a result are critical inputs in the analysis that determines which energy efficiency measures should be offered to customers in the energy efficiency programs in Illinois. Staff asserts measure lifetimes are also another critical input in the TRC analysis that has not been studied in Illinois and that can have a huge impact on TRC results. Staff suggests the value of such a study can also be discussed at the TRC workshops. (Staff Reply at 14-15)

A review of the NRDC Report on NEBs and ComEd's Responses to Objections leads Staff to conclude that a generalized adder may be inappropriate and that the NRDC Report in itself is not sufficient to justify increasing Ameren's adder to some value greater than 10%. It appears to Staff that Ameren's 10% adder lacks specificity and may be nothing more than an arbitrary value that serves as a placeholder recognizing that some non-energy benefits exist. Staff is skeptical whether such an

approach comports with the statutory definition for permitting the inclusion of other quantifiable societal benefits. (Staff Reply at 15)

Staff investigated the source of those adders and learned that the inclusion of a 10% NEBs adder has been a rule for many years in Iowa and there is no detailed quantitative analysis available to support it. Staff believes specificity is currently lacking in Ameren's assumed benefit adders already used in the TRC analysis of the programs in this docket. (Staff Reply at 16-17)

According to Staff, the NRDC Report also seems to support the notion that every energy efficiency program may have different appropriate NEB adder values and that arbitrarily assigning a default NEB value to a program may be incorrect. The NRDC Report includes in the assessment of NEBs, certain benefits categories that if applied to Illinois, would lead to the double counting of benefits from the perspective of the Illinois TRC and would distort the TRC results. The NRDC Report also includes benefits categories that, in Staff's view, appear to represent transfers rather than real benefits, again if applied to Illinois utility TRC analysis, it would result in distortions in the Illinois TRC test results. (Staff Reply at 17)

Staff claims a residential Lighting program is likely to have significantly different benefits for added comfort and reduced noise than a residential HVAC program. Staff says the significance of reduced arrearages is also likely to depend on program design. Staff asserts a weatherization program such as the one evaluated in the NRDC Report is more likely to target lower-income households and to achieve large percentage reduction in total electricity usage. Staff adds that a program that targets more affluent customers with lower per unit savings is less likely to result in similar arrearage reductions. Staff suggests a weatherization program is also likely to have significantly different water savings than either a Clothes Washer program, Lighting program, or an HVAC program. Staff claims the IL-TRM already quantifies water savings for purposes of Illinois TRC cost-effectiveness analysis, and thus applying the NRDC Report NEB values to Illinois programs could result in double counting of benefits and make uneconomic programs falsely appear cost-effective. (Staff Reply at 17-18)

Staff states that the inclusion of the value of reduced green-house gas ("GHG") emissions appears to be a separate item in the Illinois TRC test as the law allows for the inclusion of reasonable estimates of likely financial costs associated with future regulation of GHG emissions. Staff says Illinois utilities already include estimated costs for future carbon legislation either as an explicit adder in the TRC model or it is included in their avoided cost estimates. Staff claims adopting the NEBs from the NRDC Report would distort the TRC results by double counting benefits within the model. Staff suggests basing a judgment that Ameren's NEBs adder may be too low based on this NRDC Report again seems inappropriate. (Staff Reply at 18)

Staff says the NRDC Report categorizes increased home values as a societal benefit. This seems inappropriate to Staff because an increased sales price means that seller receives additional benefits but that the buyer pays additional costs. In the end,

this is neither a benefit nor a cost. Staff says it represents a transfer from the buyer to the seller. The inclusion of benefits from this category is likely to overstate NEBs. (Staff Reply at 18-19)

A review of NRDC's Responses to Objections leads Staff to believe that marginal line losses may more accurately reflect reduced usage than average line losses do and as such are more appropriate to value for purposes of a TRC analysis. Staff understands line losses to increase as capacity is added to a line. Staff says as a result, removing the last unit of electricity from a line results in a greater reduction in line losses than what is measured by the average value. (Staff Reply at 19)

Staff says its Responses to Objections misinterpreted NRDC's objections to Ameren's administrative costs as being an attempt to block some real administrative costs that are typically assigned to the portfolio-level of the Section 8-103 programs from being assigned to the program-level for programs administered as part of the IPA procurement process. Based on NRDC's position clarified in its Responses to Objections, NRDC was actually objecting to an administrative cost adder of 14% being used to estimate administrative costs for Ameren's programs. (Staff Reply at 19-20)

NRDC contends that Ameren improperly factored in non-existent education and marketing costs and if those costs were excluded, NRDC calculates that AIC's presumed adder could be reduced from 14% to 8.5%. Staff says it made this adjustment to the TRC analysis and found only one additional program (i.e., School Direct Install program) would pass the TRC test based on this change. Staff states given that benefits may already be overstated since it appears the 10% electric NEBs adder Ameren used in its TRC analysis may not be appropriate given the failure to satisfy the quantifiable requirement specified in the Illinois TRC test as ComEd pointed out, reductions to Ameren's administrative costs by fixed percentages across the board may only serve to further distort the TRC analysis. (Staff Reply at 20)

NRDC contends that administrative costs do not usually increase linearly or proportionally with budget. Staff agrees that in some cases the program administrative costs do not increase linearly with the program budget. Staff claims program administrative costs can be very dependent based on program type and individual program-specific estimates for administrative costs would be the preferred approach for inclusion in the TRC analysis. In Staff's view, Ameren's use of fixed percentage administrative costs may be unfairly penalizing large energy efficiency programs proposed by vendors, and continued use of such fixed percentage adder might encourage future bidders to bid in smaller sized energy efficiency programs in the future. (Staff Reply at 20)

Section 16-111.5B program administrative costs will also depend on how much Ameren is willing to be involved with the vendors to help promote the third-party energy efficiency programs. Based on past filings by ComEd, Staff understands ComEd minimizes its involvement in actively marketing many of the Section 16-111.5B third-party vendor programs. Staff says Ameren appears to be more willing to be actively

involved with marketing to help ensure the third-party program's success. NRDC argues that ComEd did not assume any additional administrative costs in its TRC screening of the Section 16-111.5B programs and thus NRDC believes Ameren's administrative costs should be closer to $0. Staff maintains the differences between each utility's role in their Section 16-111.5B third-party program marketing and management, it does not seem reasonable to expect Ameren and ComEd administrative costs to be comparable for all the Section 16-111.5B energy efficiency programs. Nevertheless, Staff believes it was improper for ComEd to exclude real administrative costs (e.g., evaluation costs, costs for contractor hired by ComEd to manage the third-party programs) in the TRC analysis for the Section 16-111.5B energy efficiency programs and believes this issue can be explored further in the 2015 TRC workshops. (Staff Reply at 21)

Staff indicates Ameren has not conducted any analysis of the administrative costs of the Section 16-111.5B programs as a percentage of total program expenditures. Staff also indicates that the basis for the adders is previous Commission approval of the procedure in Docket Nos. 10-0568, 13-0498, 12-0544, and 13-0546. For the sake of clarity, Staff says the Commission never formally addressed such procedure explicitly in the Orders in those dockets. Staff asserts the lack of analysis of Ameren's actual administrative costs incurred to run the Section 16-111.5B programs makes it difficult to determine whether a 14% assumption is reasonable. (Staff Reply at 21-22)

According to Staff, the lack of well-established stand-alone energy efficiency programs administered as part of the utilities' Section 16-111.5B energy efficiency portfolio also makes it difficult to apply historical precedence to approximating the administrative costs. Staff believes the Commission should direct further assessment of actual administrative costs to be conducted as the information becomes available during the 2015 TRC workshops. Staff says clear definitions and descriptions of administrative costs incurred under Section 8-103 versus Section 16-111.5B will also be necessary to establish during the workshops in order to ensure costs are being properly allocated to each program and portfolio. Staff believes the Commission should direct the utilities to make best efforts to track administrative costs by program in order to aid in future determinations of appropriate assumptions to use in the TRC analyses. (Staff Reply at 22)

In ComEd's Response to Objections, it argues that a Staff proposal to choose the energy efficiency program with higher net benefits among duplicative programs, would attempt to transform this simple threshold determination, a TRC benefit-cost ratio greater than 1, into a net benefits ranking test, a purpose for which it was not designed. The IPA contends that providing the Commission with the TRC net benefit information is "unnecessary."

Staff is confused by ComEd's summary and the remainder of its argument on this subject as Staff is not proposing that the threshold TRC benefit-cost ratios be excluded from the procurement plan. Staff says it is proposing additional information be included

in the plan, namely a simple modification to how the TRC results are presented in order to provide the Commission with more information to consider about duplicative programs. (Staff Reply at 23)

Staff says it is merely attempting to address which program should be included when two programs are duplicative and cannot coexist and argues that the energy efficiency program with the higher TRC net benefit should be selected. Staff asserts its recommendation does not represent a difficult or costly deviation from what the TRC ratio was envisioned. Staff says given all cost-effective programs are to be included in the IPA plan filed with the Commission; the final choice between which duplicative program should be chosen is ultimately the Commission's decision. Staff claims providing the Commission with the TRC results for the programs can provide useful information for the Commission to consider when making the determination about which duplicative program should be approved. (Staff Reply at 23-24)

Staff states that historically, the Commission has found the amount of TRC net benefits produced by energy efficiency programs to be quite useful in guiding the Commission's conclusions in energy efficiency dockets. Staff asserts the Commission has indicated in numerous dockets its desire that utilities implement energy efficiency programs in a manner that increases and maximizes net benefits for Illinois ratepayers, and found such direction consistent with the energy efficiency statute. (Staff Reply at 24-25)

Staff says the Commission has found net benefits to be of importance historically and Staff has no reason to believe such information will not continue to be of importance to the Commission. Staff finds it ironic that ComEd apparently found the amount of projected net benefits to be of some importance too in its last energy efficiency plan docket when ComEd argued that the large amount of net benefits essentially reduces the risk of the TRC to reduce to below one during implementation. Staff believes providing the TRC net benefit information can be useful to the Commission in future proceedings and as such it should be presented in future procurement plans. (Staff Objections, 15-16)

ComEd asserts that how it treats customer incentive costs in the TRC Test results in the TRC costs not including customer incentive costs, and because incentive costs can comprise 50% or more of a total program's expenditures, the absence of this cost component can result in highly distorting "net benefits" results under the TRC Test. Staff states that any distortions in the TRC net benefits would also distort the TRC ratio. Staff believes there is an appropriate remedy to remove such distortions from ComEd's TRC analysis and the details can be worked out in the TRC workshops. (Staff Reply at 26)

Staff says if all customer incentive costs were added to the cost side of the TRC test then double counting of costs would occur because the full incremental participant/customer/measure costs are already included in the TRC, net of free riders. Staff believes the distortions ComEd mentions is largely a function of how it classifies

incentive costs in the TRC analysis and how it computes the net participant/customer/measure costs. Staff says incentive costs are used to offset customer/measure costs. Staff claims incentive costs should not exceed incremental participant/customer/measure costs. (Staff Reply at 26)

Staff says given ComEd's past and inconsistent practice across time of how it treats incentive costs and participant costs in the TRC analysis of its programs, Staff believes that any distortions in the TRC net benefits is largely a function of incorrect treatment of certain costs in the TRC analysis. If ComEd's TRC analysis is distorted, as ComEd claims, then Staff says such distortions can be explained in the energy efficiency assessments submitted under Section 16-111.5B and the Commission can consider the merit of those perceived distortions when making a decision about the energy efficiency programs to approve. Staff believes the distortions raised by ComEd in its TRC analysis can be appropriately remedied by ensuring that the free riders' participant/customer/measure costs that are offset by the utility incentives are included as costs in the TRC analysis. Staff's rationale for such inclusion is that these are real costs expended by the program. Staff claims this approach is used in California and has been used in Ameren's cost-effectiveness analysis. Staff also notes that recent updates to DSMore make it very easy to incorporate this modification into the TRC analysis in order to prevent distortions in the net benefit results that ComEd mentions. (Staff Reply at 26-27)

According to Staff, all that is required is typing a single number in the spreadsheet and the analysis will treat free rider incentives as administration costs in the TRC analysis. Staff believes it would be valuable for the utilities to include the TRC results (both TRC ratio and the TRC net benefits) in their energy efficiency assessment submitted to the IPA per Section 16-111.5B under both the California approach that treats free rider incentives as administration costs and the approach where free rider incentives are excluded from the cost side of the TRC equation. Staff says this will allow for sufficient transparency in the TRC results. Staff also believes such approach is consistent with the TRC test definition found in the IPA Act that requires the costs include "the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program", and given the utility incentive cost contribution that is paid to free riders is "due to the program", it seems reasonable to Staff to interpret that as requiring that portion of incentive costs be included as a cost in the TRC calculation. (Staff Reply at 27-28)

Staff supports the IPA's proposal for the TRC workshops, including Ameren's modifications, with certain clarifications added that would ensure the TRC workshop consensus recommendations and other findings are reported to the Commission in next year's procurement docket. Staff maintains Commission adoption of the NRDC position to include DRIPE in the Illinois TRC test in this docket would be a significant and dramatic departure from past Commission practice concerning the TRC analysis for energy efficiency programs. (Staff Reply at 28)

Staff says the gas utilities and DCEO who operate energy efficiency programs in Illinois are not active parties to this docket and it would not be fair to adopt NRDC's proposals concerning the TRC methodology that dramatically deviates from past Commission practice and that could have implications on the other program administrators operating energy efficiency programs in Illinois. Staff understands that the utilities will not make certain changes to their TRC analyses unless the Commission explicitly orders it. To the extent the Commission determines that it is important for the various utilities and DCEO administering energy efficiency programs in Illinois to perform the TRC cost-effectiveness analysis using a consistent set of approved approaches, then Staff believes there would be a need for a separate docketed proceeding (not the procurement docket) at the end of the TRC workshops to have the Commission resolve the remaining outstanding TRC methodology issues where consensus cannot be reached through the workshops. (Staff Reply at 28-29)

If the Commission believes that having consistent TRC methodology approaches is not necessary for use by the various program administrators of the energy efficiency programs in Illinois under Sections 8-103, 8-104, 8-408, and 16-111.5B, and the IPA in conducting its cost-effectiveness review of the third-party program bids when determining which energy efficiency programs should be included in the procurement plan per Section 16-111.5B, then Staff believes the Commission should adopt Staff's primary recommendation to modify the IPA Plan that would simply require TRC workshops to be conducted in 2015, the results of which would be reported to the Commission in next year's procurement docket. If the Commission finds that it is desirable to have consistent TRC methodologies statewide for use in evaluating programs pursuant to Sections 8-103, 8-104, 8-408, and 16-111.5B, then Staff believes the Commission should adopt Staff's alternative recommendation. (Staff Reply at 28-29)

Staff says it would support the Commission opening a docket separate from the procurement proceeding after the 2015 TRC workshops conclude, wherein the Commission can carefully consider and formally resolve any remaining outstanding TRC methodology issues. If the Commission wishes to encourage a consensus seeking process for the establishment of Illinois TRC methodologies, then Staff believes it is critical that the TRC workshops are held first prior to litigation in a docketed proceeding in order to allow all interested parties to gain a better understanding of the different TRC methodologies currently used by the various program administrators and clearly identify areas where parties are able to reach consensus. Staff suggests to the extent consensus is able to be reached on a number of TRC methodology issues, it would be most efficient to have those consensus Illinois TRC methodologies memorialized in Attachment B to the IL-TRM. It seems reasonable to Staff to keep all the TRC-related issues together by having the TRC methodologies set forth in an attachment to the IL-TRM, a document most parties are already very familiar with in Illinois. (Staff Reply at 30-31)

Once the Commission resolves the non-consensus TRC methodology issues, Staff suggests the resolution would be incorporated into Attachment B of the IL-TRM

with the next IL-TRM Update. Staff says the time-constrained procurement plan docket that does not involve DCEO or the gas utilities is not the appropriate place to carefully consider and resolve all the complex TRC methodology issues. (Staff Reply at 31-32)

Staff notes a number of parties commented on whether the Commission should explicitly order collaboration by the utilities with various stakeholders in the third party bid review process. Staff says with the exception of perhaps Ameren, the rest of the parties commenting seemed generally supportive of the concept. Staff Reply at 32-33)

Generally, Staff thinks it would be beneficial to the IPA, the Commission, and ultimately ratepayers to have additional, independent sets of eyes providing critical qualitative reviews of the third party program bids submitted under Section 16-111.5B. Staff also supports the Commission requiring Ameren to submit a confidential bid review document with its energy efficiency assessment similar to the one submitted by ComEd. Staff notes that participants in the 2013 energy efficiency workshops reached consensus that qualitative information should be submitted with the utilities' energy efficiency assessments. It is unclear to Staff why Ameren has not submitted such bid review documents during the last two cycles despite such consensus. Staff believes the Commission should order such confidential bid review submittals to include more detail concerning the rationale for the competing and duplicative determinations as well as the facts considered by the utilities and stakeholders in making those determinations. Staff believes this will provide the Commission with more information to work from when making decisions in the time constrained procurement proceedings. (Staff Reply at 33-34)

Staff also agrees with the IPA, Ameren, and ComEd that such independent reviewers should have no decision-making authority and would recommend the Commission emphasize that the utilities are entirely responsible for preparing their annual July 15 energy efficiency assessments that get submitted to the IPA pursuant to Section 16-111.5B of the PUA when making a decision on this issue. (Staff Reply at 34)

The lack of detail provided in this proceeding in the filings of stakeholders, particularly of those who participated in the utilities' collaborative third party bid reviews, raises red flags for Staff. Staff claims such stakeholders should be aware of certain key details learned through the bid review process without having to submit data requests in this time-constrained proceeding. Staff says it requested and received copies of both the ComEd and Ameren confidentiality agreements that each required stakeholders to sign prior to the collaborative third party bid review process. Based on a review of such contracts, Staff is concerned about the Commission not receiving a full level of guidance in these procurement proceedings from stakeholders due to the fact that the stakeholders signed confidentiality agreements with the utilities. (Staff Reply at 34)

Staff says this is of concern particularly because those stakeholders have expertise in such matters and are at least somewhat familiar with the utilities' energy efficiency assessments submitted to the IPA pursuant to Section 16-111.5B, the

assessments of which consist of literally hundreds of pages (maybe even thousands). To ensure the Commission is informed of critical information of relevance to a proceeding, Staff believes the Commission should state in the final Order that Ameren and ComEd shall include the following language in their future contracts with stakeholders they engage in reviewing the Section 16-111.5B third party program bids and "duplicative" program determinations:

> *[Recipient or Recipient's Representatives or Receiving Party (i.e., stakeholder)]* shall be permitted to disclose on a confidential basis any Confidential Information subject to this Agreement in regulatory proceedings before the Illinois Commerce Commission to the Commission, Commission Staff, and parties in those proceedings. Such Confidential Information must be redacted from the public version of the filings.
> (Staff Reply at 34-35)

Staff contends that the two behavioral programs included in the Proposed Plan for implementation in the Ameren service territory are not duplicative and can successfully coexist. Staff believes the Commission should reject the IPA's contention that two opt-out (i.e., certain customers are automatically enrolled) behavioral programs sending home energy reports to customers are duplicative and cannot coexist successfully. Staff says the behavioral energy efficiency programs consisting of home energy reports approved last year by the Commission under the Section 16-111.5B energy efficiency portfolio are currently being implemented in the ComEd service territory by two different vendors. (Staff Reply at 35-37)

Staff believes that it is likely the IPA was not aware of the fact that ComEd is currently operating its home energy report behavioral programs under Section 16-111.5B with two different vendors when it made its initial recommendation on this matter. Staff says there was no Commission requirement in the last procurement proceedings to submit updates to the Commission on the Section 16-111.5B energy efficiency programs. Staff believes it is critical that the Commission explicitly approve/adopt the consensus language set forth in the Proposed Plan at pages 75-77 that includes utility notification requirements to ensure all interested parties and the IPA and the Commission are kept informed of updates and changes to the approved Section 16-111.5B energy efficiency programs.

Staff agrees in part and disagrees in part with Ameren's characterization of the Commission's directive to include the behavioral modification program in the procurement plan under Section 16-111.5B. While the Commission used the term "transfer" in discussing moving programs from the Section 8-103 portfolio to the Section 16-111.5B portfolio, the Commission also clarified that the purpose of such "transfer" is "to further expand" those successful cost-effective programs. Staff states despite the Commission's direction that the purpose of such transfers to the Section 16-111.5B IPA portfolio is to allow the energy efficiency programs to expand in size, Ameren

nonetheless has decided it would limit the size of the behavioral programs in its cost-effectiveness submittal to the IPA. (Staff Reply at 38-39)

Ameren's proposal that requires Section 8-104 gas funding to pay 50% of the total cost of any proposed behavioral program (that 50% is limited to $2,224,375 for PY8 and PY9 combined) appears to Staff inconsistent with the Commission's requirement for expansion of the behavioral programs under Section 16-111.5B. Staff claims that ComEd had no problem submitting expanded programs as directed by the Commission in its docket. (Staff Reply at 39)

While Ameren claims that its decision to "run the behavioral modification programs functionally as a dual fuel program" was an effort to "maximize benefits," Staff believes the facts do not support Ameren's claim. Staff claims significant amounts of cost-effective savings and potential benefits are being eliminated. Staff states that Ameren's constraining of the size of the behavioral programs by requiring half the funding to come from its Section 8-104 gas portfolio budget has resulted in one of the behavioral programs actually projecting it will not meet the gas savings goals associated with that budget. Staff finds ironic the one the IPA recommends the Commission adopt is the Home Energy Report program. Staff says the Commission should reject such approach. (Staff Reply at 39-40)

Staff disagrees with Ameren that the Commission explicitly required the behavioral modification program "transferred" to the Section 16-111.5B portfolio to "still be run in conjunction with Ameren Illinois' Section 8-104 gas behavior modification program." Staff claims it was actually Ameren that was insisting that the behavioral modification program is a "dual fuel" program and as such it must remain in the Section 8-103 portfolio. Staff claims this was an attempt to prevent the Commission from transferring the behavioral program to the Section 16-111.5B portfolio, which could make it more difficult for Ameren to meet its Section 8-103 goals considering it's relatively easier to achieve savings from the behavioral modification programs since customers are enrolled automatically. The Commission ultimately rejected Ameren's position and determined the behavioral programs should be transferred to Section 16-111.5B in order to expand the program and "maximize all available funding for energy efficiency programs in Illinois." (Staff Reply at 40)

Staff says rather than excluding Ameren's gas-only customers from receiving home energy reports, as Ameren's proposal in this docket would do, Staff believes it is reasonable for the Commission to approve the expanded behavioral programs in this docket pursuant to Section 16-111.5B of the PUA. Staff suggests after approval, Ameren can work with the two behavioral vendors to determine what the most cost-effective approach would be for achieving its gas savings goals under Section 8-104 as well as for expanding savings under Section 16-111.5B. Staff says such post Commission approval finalization of Section 16-111.5B program details, along with the flexibility granted to Ameren pursuant to Section 8-104 in Docket No. 13-0498, is consistent with the consensus approach recommended by the IPA in its Plan, and opposed by no party in this proceeding. Staff urges the Commission to adopt the

consensus language set forth in the Proposed Plan in order to increase certainty for all parties involved with the Section 16-111.5B energy efficiency programs. (Staff Reply at 41)

Staff states that Ameren's 50% gas funding/50% electric funding requirement that Ameren imposed on each of the two behavioral program bids has been set arbitrarily by Ameren. Staff says the Commission never explicitly ordered that split in Docket No. 13-0498; it was not a contested issue. Staff says Ameren assumes different gas/electric funding splits other than 50% gas/50% electric funding for other Ameren energy efficiency programs that provide dual fuel savings. (Staff Reply at 42)

Given Ameren's explicit deviations historically from the 50% gas funding/50% electric funding split for dual fuel programs based on the "disparate amounts of total budget available for each fuel," Staff is unsure why Ameren did not include such a proposal in this docket to expand the size of the behavioral programs as directed by the Commission's Order in Docket No. 13-0498. Staff says the Commission addressed gas and electric funding of dual fuel savings measures in the Commission's Order in Ameren's energy efficiency plan 2 docket. (Staff Reply at 42-43)

It seems to Staff that Ameren should be allowed to fund a measure resulting in both gas and electric energy savings (i.e., behavioral programs targeting Ameren's dual fuel customers), and charge the full (or even just more than 50%) incentive cost of the measure to the electric Section 16-111.5B portfolio, so long as the measure results in sufficient benefits to electric customers that it is likely to be provided by an electric-only utility. Staff says given ComEd is an electric utility operating behavioral programs that target and achieve dual fuel measure savings, Staff believes the Commission's condition has been satisfied and Ameren should be permitted to fund the behavioral programs through Section 16-111.5B. Staff is not suggesting that the entire amount must be funded through Section 16-111.5B, but believes Ameren can make the determination of the appropriate percentage funding splits based on guidance provided in past Commission Orders. Staff suggests the final splits can be submitted to the Commission in compliance filings in this docket with the rest of program modification details. (Staff Reply at 44)

Staff also believes that when Ameren works with both vendors to refine the targeted households that in addition to the dual fuel Ameren households that were included in both vendors' proposals, not only should Ameren consider sending reports to those gas-only Ameren households (funded with the Section 8-104 gas budget) as explained above, but it should also consider expanding the behavioral programs to the electric-only households who are Ameren customers (funded with the Section 16-111.5B electric funds) who have never received any home energy reports through Ameren's existing behavioral program. (Staff Reply at 44-45)

Staff is confident that if the Commission approves both behavioral program vendors then changes such as these could easily be incorporated when finalizing the program design and contracts to ensure the behavioral program is actually being

expanded per the Commission's directive in Docket No. 13-0498, consistent with the consensus approach that requires that final modifications to the programs must continue to result in a cost-effective program and the changes will be reported to the Commission in a compliance filing in the procurement proceeding. (Staff Reply at 45)

Staff says expanding the behavioral programs in this manner by targeting not only Ameren's dual fuel customers, but also Ameren's gas-only customers (under Section 8-104) and Ameren's electric-only customers that include some electric-only households, will eliminate the concerns expressed by Ameren and the IPA concerning program sizes being constrained by approving two vendors. Staff states that based on Ameren's "requirement" that it created that limits the size of the behavioral programs by requiring 50% of the funding come from Ameren's Section 8-104 portfolio (this funding amount Ameren also arbitrarily holds fixed despite the significant amount of flexibility granted to Ameren in regard to shifting funds across programs as approved in Docket No. 13-0498), both Ameren and the IPA express concerns that approving two behavioral vendors would further limit the size of the behavioral programs, because presumably the 50% gas budget amount would have to be reduced to 25% for each vendor, resulting in programs half the size of the amounts presented in Table 7-2 of the Proposed Plan. Staff says the sizes of the behavioral programs should not be constrained by the gas budgets. (Staff Reply at 45-46)

As far as dividing customers between the two programs, Staff contends that Ameren should use reasonable and prudent judgment and make that decision when it is finalizing contracts with each vendor. (Staff Reply at 46)

While Staff is not opposed *per se* to Ameren taking a similar approach as ComEd and working with its existing Home Energy Report vendor to perform the customer segmentation analysis, Staff believes a better approach would be to have Ameren make the final decision about who should take the lead in performing the analysis based in part on the costs charged by various parties for such an analysis. Ameren should obtain price estimates from Ameren's existing behavioral vendor, the other behavioral vendor, and Ameren's independent evaluator Opinion Dynamics in order to compare the various costs to perform the analysis. (Staff Reply at 47)

Staff claims the main reason identified by Ameren and the IPA that caused them to believe the two behavioral program vendors do not pass the competing and duplicative proposal test was due to their mistaken belief that "implementation of both programs would be both confusing and counterproductive, with savings from one program cannibalizing the other." The Proposed Plan goes on to claim that "running multiple programs would lead to significant confusion of residential customers, which would hamper adoption of the Behavioral Modification program, rather than increase it." Staff believes the IPA's and Ameren's concerns are not valid. Staff also notes that ComEd currently manages the largest Power Home Energy Report program in the United States. Staff claims the fact that ComEd was able to also allow another behavioral program home energy report vendor to operate within its service territory is very telling in terms of the feasibility of such approach. (Staff Reply at 49-50)

In arguing that the two behavioral programs are duplicative and could not successfully co-exist, the IPA identifies what it refers to as practical implementation issues related to how Ameren's website would direct customers to the correct website. In reply to the IPA's concerns, Staff states the behavioral programs are both structured as opt-out programs, meaning customers receiving the reports are randomly chosen to receive those reports, and thus there is no need to advertise the program through Ameren's website. Staff says a visit to Ameren's energy efficiency website to search for a link to Ameren's existing vendor's website for the Home Energy Reports Program is a dead end search, as there is no such link available on Ameren's website. Staff suggests providing a link to the Home Energy Report Program vendor's website on Ameren's website could yield customer confusion if advertised as a program since customers do not "sign up" for this opt-out program. Even if Ameren's website began providing links to both vendors' web portals, Staff says it would simply increase the wealth of information concerning energy savings tips available to customers and would not be harmful. (Staff Reply at 51)

Staff says Ameren currently provides links to a variety of energy-related resources on Ameren's website, such as the ENERGY STAR® website and the U.S. Department of Energy's website. To the extent customers in the behavioral programs should access the vendors' websites, Staff says the vendor's website information can be included on the actual report, it can be sent through e-mails to those customers, and it can be provided on inserts provided with the report. Staff claims this approach to communicating the website information to customers has already been used successfully by ComEd for its behavioral program. Staff argues that no confusion will exist because it is very unlikely that a vendor would accidentally put the other vendor's web address on the report they send to the customers they target. Staff says while the IPA's concern might be applicable for opt-in energy efficiency program types where customers might search the utility's website to learn more information about the program and how to sign up or submit rebate applications, it is not a concern for the opt-out behavioral programs at issue in this proceeding. Staff urges the Commission to reject the IPA's contention concerning websites being a practical implementation issue that prevents the two behavioral programs from coexisting. (Staff Reply at 51-52)

The IPA indicates it would not oppose an adjustment in target size to allow both behavioral programs to coexist, but the IPA contends there are practical implementation issues that may make this infeasible. Staff insists there are not practical implementation issues that would make coexisting behavioral programs infeasible. Staff urges the Commission to find the two behavioral programs are not duplicative and direct Ameren to engage the vendors after Commission approval in a manner consistent with that recommended by Staff in order to ensure the programs in the procurement plan fully capture the potential for all achievable cost-effective savings as required by Section 16-111.5B(a)(5) of the PUA. (Staff Reply at 52)

Staff says competing programs can successfully coexist in the market while duplicative programs cannot, and a selection between duplicative programs must be

made in the event the Commission determines that two cost-effective programs are duplicative. If the Commission determines the two behavioral programs are duplicative, then Staff believes the Commission should approve the Behavioral Energy Efficiency Program vendor at the level initially proposed by the vendor, which targets 570,000 households. Staff believes the Commission should approve this highly cost-effective behavioral program that is projected by Ameren to provide net benefits to ratepayers in the amount of $7,934,118. (Staff Reply at 53)

The IPA claims that it does not oppose selection of the Behavioral Energy Efficiency Program, but believes that the balance of relevant evidence supports including the Home Energy Reports Program. Staff says it has no idea what evidence the IPA relies upon to support this statement given the IPA provides virtually no evidence in this proceeding concerning the behavioral programs and their performance, despite Staff's requests that the IPA should provide such information to the Commission in this proceeding. The IPA contends that it is the difference in "likelihood of program success" that leads the IPA to recommend inclusion of the Home Energy Reports Program. Staff says it provided the *ex post* TRC results for the Home Energy Reports Program for PY3 and PY4 that showed the program was not cost-effective, in total producing --$1,637,369 in net benefits to Illinois ratepayers. Staff says it also pointed out the significant variability in the *ex post* savings estimates produced by the Home Energy Reports vendor, and thus is confused by the IPA's confidence in the Home Energy Reports vendor's savings estimates. Staff believes these facts in this case do not support the IPA's arguments. (Staff Reply at 54)

Staff contends the adoption of the Home Energy Report Program in lieu of the Behavioral Energy Efficiency Program undermines Ameren's ability to meet its Section 8-104 gas savings goals within the budget approved in Plan 3. Staff claims the Home Energy Report Program does not contemplate meeting Ameren's therm savings goals 1,887,500 therms per year within budget whereas the Behavioral Energy Efficiency Program forecasts exceeding the therm savings goals within budget. (Staff Reply at 54-55)

Staff contends if the TRC analyses are performed using the best available information and using credible inputs, then it is sound to use the amount of projected net benefits when making a determination. Staff says it adjusted the Behavioral Energy Efficiency Program vendor's savings estimates in a conservative manner and found that its initial bid that targets 570,000 Ameren households results in significantly greater net benefits to ratepayers and it should be approved. (Staff Reply at 55-56)

Staff says the IPA took issue with the Behavioral Energy Efficiency Program vendor's estimates and instead recommended approval of the Home Energy Reports vendor. Staff says it requested the IPA provide revised TRC calculations using assumptions that reflect its best estimates of the savings, but the IPA provided no revised estimates in response. Staff contends that it is not reasonable for the IPA to adjust savings with no evidence from that vendor's evaluated programs, especially given the different proportions of legacy versus new households. (Staff Reply at 56-57)

Staff claims there are legitimate reasons to think that the Behavioral Energy Efficiency Program's savings will be higher than the Home Energy Report Program's savings, and based on the filings by the IPA, it appears these factors were not considered in making their recommendation. (Staff Reply at 57-58)

If the Commission determines the two behavioral programs are duplicative, then Staff says the Commission should approve the Behavioral Energy Efficiency Program vendor at the level initially proposed by the vendor, which targets 570,000 households and that is projected by Ameren to provide net benefits to ratepayers of $7,934,118 (or net benefits to ratepayers in the amount of $1,352,414 as estimated by Staff). Staff says the Commission should approve this highly cost-effective behavioral program for inclusion in the procurement plan. (Staff Reply at 59-60)

The IPA contends that adopting a non-incumbent vendor's proposed program that is forecasted to provide greater net benefits but has lower likelihood of program success could create a perverse in incentive for future bidders of "weaker programs" to potentially manipulate estimated energy savings values to win analyses against stronger "duplicative" programs. Staff states that given the cost-effectiveness threshold that currently exists, some incentive to overstate savings claims may already exist. The IPA then clarifies that "these analyses" (presumably duplicative analyses) must be made on a case by case basis and incumbent providers should not presume that they will inherently be given an advantage. The IPA states that its recommendation between the two duplicative "programs is based on a qualitative consideration of multiple factors." In Staff's view, this statement begs the question as to whether the Commission should consider qualitative information when determining whether any energy efficiency program should be approved, or whether the IPA should only consider qualitative information when choosing between two duplicative programs. Staff supports the Commission considering qualitative information about the energy efficiency programs when determining whether any energy efficiency program should be approved, but Staff notes that it appears the IPA has only considered such qualitative information in the case of duplicative energy efficiency programs. Should the Commission desire qualitative information be used in the analysis of all Section 16-111.5B third party program bids, Staff urges the Commission to make this clear in the final Order in this docket. (Staff Reply at 60-61)

In its Brief on Exceptions, Staff says its concerns pertaining to Ameren's use of a "default" externality adder across all programs, rather than using program-specific NEBs adders that represents real "quantifiable societal benefits" relevant to particular program types is well taken. Staff claims this is one reason that the Commission does not require Ameren to re-evaluate the cost-effectiveness of the three "near miss" programs using more representative program administrative cost adders as recommended by NRDC. According to Staff, a key reason the Commission does not require Ameren to re-evaluate the cost-effectiveness of the three "near miss" programs is that essentially no evidence is provided by NRDC concerning the three "near miss" programs (e.g., program name, target market, program design, cost). Staff asserts NRDC provides no

analysis of whether the three “near miss” programs pass the competitive and duplicative program tests and thus it is not clear whether the three “near miss” programs would conflict with any of the cost-effective programs already included in the Plan or operating under Section 8-103. Staff suggests that perhaps the collaborative utility and stakeholder bid review process may be the appropriate forum to determine what impacts parties’ recommendations might have. Staff believes the lack of evidence presented on the three “near miss” programs makes it impossible for the Commission to order their inclusion in the Plan. (Staff BOE, Attachment A at 221-222)

In its Brief on Exceptions, Staff proposed significant modifications to the Proposed Order conclusions regarding incremental energy efficiency issues.

5. ComEd’s Position

Staff proposes that the legislatively-defined standard for determining whether measures are “cost effective” now be used for an entirely different purpose – calculating “net benefits.” ComEd contends the TRC Test was neither intended nor suited for the measurement of net benefits. (ComEd Response at 3)

ComEd says the General Assembly created the Illinois TRC Test in 2007 as part of Public Act 95-0481. ComEd also states that the purpose of Section 8-103 of the PUA, is to assist the utility in selecting which energy efficiency measures and programs should be included within its energy efficiency portfolio. To this end, ComEd claims the TRC Test serves as an initial (or “threshold”) indicator for whether the measure or program might be included within the portfolio by indicating, through a simple ratio, whether the benefits exceed the costs. The legislature specifically defined the components of this ratio as follows:

> "Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program for supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.

In ComEd's view, the issue with Staff's proposal is that it would attempt to transform this simple threshold determination into a net benefits "ranking" test, a purpose for which it was not designed. (ComEd Response at 3-4)

ComEd claims that the problems associated with Staff's repurposing of the TRC Test are perhaps best illustrated by highlighting how customer incentive costs are addressed. ComEd says the TRC Test compares gross benefits to costs. ComEd adds that the TRC Test benefits include avoided energy supply costs, avoided capacity costs, avoided transmission and distribution investment, avoided cost of emissions regulation, avoided natural gas costs, and other quantifiable societal benefits. ComEd says the TRC Test costs include program implementation and marketing costs, program administration costs, and participation costs (i.e., incremental measure costs). ComEd believes it is important that TRC costs do not include customer incentive costs. ComEd claims because incentive costs can comprise 50% or more of a total program's expenditures, the absence of this cost component can result in highly distorting "net benefits" results under the TRC Test. ComEd contends this distortion would be further exacerbated if NRDC's proposed adjustments were included. ComEd believes Staff's proposal to use the TRC Test beyond its statutory purpose should be rejected. (ComEd Response at 4-5)

NRDC proposes to add extra-statutory components to the Test as it is applied to Ameren's programs. Specifically, NRDC proposes to adjust the TRC Test calculations for Ameren's programs to include DRIPE, marginal line losses, and a non-energy benefits adder so that these programs will pass the TRC Test. Although ComEd does not take issue with the inclusion of marginal line losses (and already includes such losses in its TRC Test), ComEd objects to NRDC's DRIPE and non-energy benefits adder. (ComEd Response at 5)

With respect to the proposal to include DRIPE, NRDC claims that this proposal fits under "other quantifiable societal benefits" in the numerator of the TRC Test. ComEd says while the statute does not define "societal benefits," NRDC claims that "the law necessitates that DRIPE be included as part of Ameren's TRC calculations." ComEd claims a review of energy efficiency best practices and guidance at the national level strongly indicates that DRIPE should not be included as a societal benefit. ComEd says the National Action Plan for Energy Efficiency, an initiative led by the U.S. EPA, includes the Societal Cost Test ("SCT"), which evaluates the "[b]enefits and costs to all in the utility service territory, state, or nation as a whole." ComEd says specifically, societal benefits include:

- Energy-related costs avoided by the utility;
- Capacity-related costs avoided by the utility, including generation, transmission, and distribution;
- Additional resource savings (i.e., gas and water if utility is electric); and
- Non-monetized benefits such as cleaner air or health impacts.

ComEd argues that societal benefits are those that inure to society as a whole, and do not include those savings that only reflect a transfer of wealth between parties. ComEd claims tax credits (which are an applicable benefit under the TRC Test) represent a transfer of wealth between the individual taxpayer and society and therefore are not a societal benefit under the SCT. ComEd also says a reduction in the clearing price of energy that may be associated with energy efficiency also represents a transfer of wealth between power generators and energy consumers, and therefore is not a societal benefit. (ComEd Response at 5-6)

ComEd cautions that the substantial adder proposed by NRDC (comprising as much as 40% of the avoided costs for a 15-year measure life) reflects a dramatic adjustment, and certainly is not one that should be made without considerable study and diligence. ComEd contends that adding DRIPE to the avoided costs of the TRC Test equation would only serve to turn non-cost-effective programs into cost-effective ones without adding any real benefits to the utilities or their customers. ComEd says NRDC admits its proposal is results driven when it concedes that the purpose of the adjustment is to transform failing TRC Test results for three Ameren programs into passing results. ComEd states that while NRDC does not propose that this same adjustment be applied to ComEd programs that did not pass the TRC Test, ComEd notes that applying the adjustment to these programs would likely result in artificially transforming these highly uneconomic energy efficiency programs (with TRC Test results below 0.7) into programs that pass the TRC Test. ComEd insists the adjustment should be rejected. (ComEd Response at 7)

Regarding NRDC's proposed non-energy benefits adder, NRDC claims that "[t]he non-energy benefit of energy efficiency is another 'quantifiable societal benefit' that should be independently calculated by the IPA and included as part of Ameren's TRC calculations." ComEd states although Ameren's TRC Test calculations already include a 10% non-benefit adder, NRDC claims this is "insufficient" without any analysis or evidence to support its claim. ComEd says the extent of NRDC's "argument" is reflected in a single, conclusory sentence: "Non-energy benefits, especially for low-income customers, can be dramatic in their capacity to improve the lives, safety, health, and comfort of customers – often having more value than the associated reductions in energy costs." (ComEd Response at 7-8)

According to ComEd, Illinois' statutorily-defined TRC Test in Section 1-10 of the IPA Act requires that societal benefits be "quantifiable." ComEd asserts that given NRDC is unable to quantify any incremental increase to the 10% adder already used by Ameren, the proposal should be rejected. ComEd suggests "quantifiable" implies that the benefit in question not only exists, but that it can be valued or monetized with some specificity. If NRDC cannot quantify the value of "lives, safety, health, and comfort" of customers who participate in energy efficiency programs, then ComEd believes this value cannot be included within the TRC Test calculations regardless of whether they exist. (ComEd Response at 8)

NRDC proposes that the Commission "require" utilities to collaborate with stakeholders, and Ameren suggests that the existing collaborative process conducted under the SAG be used to address any concerns raised by NRDC. ComEd states that since the inception of the energy efficiency portfolio requirements under Section 8-103 of the PUA, ComEd has worked with interested stakeholders on the development of energy efficiency programs. ComEd has no objection to soliciting or considering input from stakeholders regarding Section 16-111.5B programs, and would support using the SAG as a forum for receiving this input so long as SAG resources are sufficient for accommodating this added process. ComEd says because the nature of NRDC's concerns is somewhat vague, ComEd wishes to clarify, however, that input received from stakeholders must be nonbinding, consistent with past Commission orders, and the fact that the utilities are ultimately responsible for program implementation. (ComEd Response at 8-9)

According to ComEd, it is necessary to convene all parties that have a stake in TRC Test issues given that the Test applies to Illinois electric and gas utility energy efficiency programs. ComEd believes it would be unfair to stakeholders who are not participating in this docket to adjudicate here core issues regarding the TRC Test without their participation. While NRDC complains that Ameren's outreach was not as transparent as it would have liked, ComEd claims NRDC equally fails to fully include all interested stakeholders in the consideration of its TRC Test proposals, preferring instead to quickly obtain approval of these sweeping adjustments in an electric utility-specific docket without substantial evidence or sufficient participation of all affected parties. In ComEd's view, the IPA correctly cautions against rushing into the adoption of any new criteria, and notes that such changes may be more effectively implemented by broader consensus developed through the state's well-established SAG process, providing more ample opportunities for feedback. (ComEd Reply at 11)

ComEd says Staff points out that DRIPE does not qualify as a "societal benefit" as required under Illinois' statutorily-defined TRC Test. Rather than refer to generic benefits, ComEd maintains the General Assembly articulated that only "quantifiable societal benefits" could be included within the TRC Test. ComEd asserts benefits that inure to only one group of people, rather than to all of society, cannot be reflected in the TRC Test; yet, this is precisely what NRDC proposes. (ComEd Reply at 11-12)

ComEd argues that contrary to NRDC's claims, DRIPE is rarely included in other jurisdictions' TRC tests. ComEd understands that just a few states incorporate a DRIPE adjustment and Illinois law does not permit its inclusion here. (ComEd Reply at 12)

NRDC continues to claim that Ameren's 10% adder to account for non-energy benefits is "overly conservative" and should be inflated, no additional information is provided that would justify any increase over the 10% already used by Ameren. ComEd says the Illinois TRC Test requires that benefits be "quantified." ComEd believes NRDC's references to a Maryland or Vermont study do not quantify any Illinois-specific non-energy benefits that NRDC claims are greater than the 10% already claimed by Ameren. ComEd asserts NRDC's "hunch" that non-energy benefits are greater than

10% is merely a convenient means to transform inefficient energy efficiency programs into programs that suddenly pass the TRC Test. (ComEd Reply at 12)

In its Brief on Exceptions, ComEd states that given the challenges inherent in considering unique contract modifications from different suppliers, ComEd proposes that, in the future, each supplier that seeks changes to the standard contract direct its comments to the utility, IPA and Staff, rather than just the utility, and that the utility, IPA and Staff consider the comments and, if appropriate, work out changes to the standard contract (on behalf of all suppliers). (ComEd BOE at 7-8)

ComEd believes the Proposed Order correctly declines to order that DRIPE and NEBs should be included in the TRC Test. (ComEd RBOE at 7-8) ComEd maintains that the present docket is not the correct forum to consider changes to the TRC Test methodology. (ComEd RBOE at 8-9) ComEd believes the Illinois TRC Test does not include DRIPE. (ComEd RBOE at 9-10)

ComEd indicates it does not take issue with inclusion of NEBs generally, as the statutory definition of the TRC Test permits inclusion of "other quantifiable societal benefits." ComEd says it has already incorporated water-saving impacts in measures such as low-flow showerheads, faucet aerators and efficient clothes washers. ComEd claims this was possible because ComEd was able to estimate the amount of water saved and, therefore, could place a monetary value on those savings. ComEd states that while it appreciates NRDC's desire to expand the list of benefits to be included, ComEd believes that parties should work together through the SAG to quantify additional NEBs with sufficient specificity to permit monetization. (ComEd RBOE at 11)

ComEd indicates it had some difficulty parsing through the many "sub-exceptions" set forth in Staff's BOE. Staff's Exception 2, in particular, is comprised of nine sub-points regarding the TRC Test, while Staff's Exception 3 sets forth four sub-exceptions, only one of which is described in the BOE. ComEd states that the lack of detail regarding certain of these exceptions and the short timeframe to prepare the Reply Brief on Exceptions further supports the Proposed Order's conclusion that workshops are a better forum for exploring these complicated issues – the compressed timeframes of procurement dockets do not lend themselves to exploring complicated cost-effectiveness and evaluation methodologies in a meaningful way. (ComEd RBOE at 11-12)

ComEd says while it understands Staff's desire to include administrative cost adders within programs' TRC analyses, no evidence has been presented in this docket that such a proposal is feasible given the highly compressed timeframe for soliciting proposals, undertaking their review, incorporating feedback from SAG, and integrating the findings into the Section 16-111.5B analysis. ComEd does not believe that either time or resources exist to develop useful estimates of evaluation costs for each proposed program, or even to assess the level of administrative oversight that each proposal's vendor will require. At best, ComEd says it may be able to develop a generic adder applicable to all programs, which would inevitably lead to the same contentious

comments directed at Ameren in this docket. ComEd recommends the issue be discussed further in workshops. (ComEd RBOE at 13-14)

Staff also proposes that the Commission direct the utilities to make best efforts to track administrative costs by program in order to aid in future determinations of appropriate assumptions to use in the TRC analyses. ComEd suggests this issue instead be left to the independent evaluator because early estimates of an administrative cost adder would be imprecise at best and immediately be subject to revision during contract negotiations and final program design. ComEd believes the issue could be addressed further in workshops. (ComEd RBOE at 14)

6. ELPC's Position

In the Plan, the IPA defers on the issue of whether utilities should be expressly encouraged to engage stakeholders in the review of third party program bids. NRDC objects to this and asks that that Commission "revise the Plan or do otherwise to expressly encourage utilities to develop requests for proposals with input from and collaboration with interested stakeholders throughout the process." Ameren notes that "the current models employed by the respective utilities already include stakeholder review. Accordingly, Ameren does not believe any "express" encouragement is needed or warranted."

ELPC agrees with NRDC's objection and disagrees with Ameren on this issue. ELPC asserts input from stakeholders in the RFP process and bid review can help parties reach consensus on which programs are duplicative, which fail to meet requirements, and which programs have potential to achieve additional energy savings in Illinois. As one of the stakeholders involved in the third party program review, ELPC found Ameren's willingness to engage very limited, too close to the proposal submission deadline, and generally unproductive. ELPC found, on the other hand, ComEd's willingness to engage much more proactive and productive. ELPC recommends that the Commission side with NRDC in this case and expressly direct the utilities to engage stakeholders in the review of third party program bids well in advance of the deadline to submit approval recommendations to the IPA and Commission. (ELPC Response at 2)

ELPC suggests the format of this participation should model ComEd's process. ELPC says the stakeholder review process with ComEd was run very well, with ComEd and its consultant holding multiple, thorough discussions with stakeholders over the course of three weeks. ELPC also says ComEd provided all stakeholders with bid proposals and score sheets well in advance of the IPA deadline; ComEd scheduled several calls to review stakeholder input and scores and to attempt to reach consensus; and ComEd promptly provided answers to stakeholder questions and followed up with other parties when needed. ELPC claims ComEd encouraged thorough discussion on each proposal and made it clear that it wanted third-party efficiency programs to succeed. ELPC believes the Commission should direct Ameren to utilize this approach. (ELPC Response at 2)

ELPC states that in the Plan, the IPA declines to examine or alter Ameren's TRC calculations for three third party programs that had a TRC greater than 0.9 and less than 1.0, despite ELPC and NRDC raising concerns that the TRC test may have failed to adequately account for DRIPE and non-energy benefits. ELPC says NRDC raised concerns in its comments that Ameren's administrative costs may be inaccurate. NRDC objects to the IPA's proposal to address this in a workshop in 2015, rather than examining Ameren's TRC calculations now. ELPC agrees that Ameren should have to justify the administrative cost assumptions it uses in its TRC test to the Commission. ELPC suggests if Ameren is not able to justify these costs, then the Commission should direct Ameren to adjust the cost assumptions and reevaluate third party programs that failed the TRC test. ELPC agrees with NRDC's objection and encourages the Commission to direct the IPA to evaluate Ameren's TRC inputs, and adjust the test to consider DRIPE, marginal line losses, and non-energy benefits. If this materially changes the outcome of the TRC for the failed third-party bids, ELPC believes those bids should be considered in the 2015 procurement. (ELPC Response at 2-3)

Staff states that historically, the Home Energy Reports program produced significant negative net benefits in Illinois. ELPC believes that such a statement distorts the value of the current Home Energy Reports program, and that Staff reaches the wrong conclusion that Ameren should use the Behavioral Energy Efficiency program. (ELPC RBOE at 4)

ELPC states that while the Home Energy Reports program may have shown negative net benefits in certain years, this is not an indication that the program is not cost effective. ELPC contends it is expected that any behavior modification program is likely to have startup costs and a lag time before it starts to change participant behavior and deliver energy savings. ELPC says the Home Energy Reports program is no exception, and that may be what Staff is referring to in its comments. ELPC indicates Staff notes based on preliminary results from most recent program years, the cost-effectiveness of both the Ameren and ComEd programs appears to be producing positive net benefits. ELPC asserts the most recent independent evaluation of the Home Energy Reports program found that in Year 5 the program saved 31,618 MWh and 1,576,341 Therms versus a planned impact of 21,705 MWh and 664,517 Therms. (ELPC RBOE at 4)

Staff notes that TRC results can easily change based on different input assumptions. ELPC agrees with this, and acknowledges that it is likely the input assumptions for the two competing behavior modification programs are not exactly correct. ELPC asserts because Home Energy Reports has been successfully running in Ameren's territory, while the Behavioral Energy Efficiency program is new to Illinois, ELPC believes it is more likely that the input assumptions for the Home Energy Reports program are more correct than those for the Behavioral Energy Efficiency program. ELPC says while both behavior modification programs have TRC scores greater than 1, and are therefore projected to be cost-effective, ELPC gives weight to the fact that Home Energy Reports has proven results in Illinois and is cost-effective as proposed.

ELPC supports Ameren's and the IPA's opinion that the Commission should choose Home Energy Reports to offer a behavioral program for Ameren. (ELPC RBOE at 5)

7. CUB/EDF's Position

NRDC asks the Commission to direct ComEd and Ameren to include in their TRC test analysis quantifiable values for DRIPE, NEBs, and avoided line losses. CUB and EDF agree with NRDC, and the IPA, that these values are already contemplated by the law as "other quantifiable social benefits" described in the TRC. CUB/EDF believe the Commission should recognize these benefits and direct AIC and ComEd to include quantifiable values for them in Section 8-103 of the PUA TRC calculations. (CUB/EDF Reply at 7-8)

Staff responds to NRDC's request for the inclusion of DRIPE into the TRC, asking the Commission to reject DRIPE on the grounds it is not actually a societal benefit, but rather a transfer of producer surplus to consumer surplus. CUB/EDF believe Staff's argument is incorrect in stating "each unit [of energy efficiency] sold provides $1 less revenue to a producer, without any corresponding decrease in production costs." CUB/EDF contend while some increase in consumer surplus would undoubtedly incur a loss in supplier surplus, there is zero reason to expect this to happen at a 1:1 ratio. CUB/EDF state that assuming an upward sloping supply curve, a decrease in consumption does result in a corresponding decrease in production costs, particularly when the marginal generator is a fossil-fuel peaker with a significant variable cost component. CUB/EDF suggest Staff may be correct, in part, that some portion of DRIPE is a transfer, and not a benefit, but rejecting 100% of DRIPE from the TRC would be incorrect. (CUB/EDF Reply at 8)

Staff supports its position by pointing to the actions of the Vermont Public Service Board ("PSB"), which first rejected the use of DRIPE in cost-benefit analysis of energy efficiency investment in 2011, only to partially reverse this decision in 2014. CUB/EDF say the 2014 PSB decision, which Staff dismisses as "[r]elying on much less cogent arguments," is instructive to this discussion. According to CUB/EDF, this decision relied on a 2011 report by the Lawrence Berkeley National Laboratory that estimated the effect of a proposed water heater efficiency standard on the natural gas market. CUB/EDF say the LBNL report found that over a 20-year period, the proposed standard would generate $48.9 billion ("bb") of additional consumer surplus, while only decreasing gas production revenues by $21.6 bb. CUB/EDF claim of the additional consumer surplus, only $9.8 bb, or 20% of the total, constituted a transfer from taxpayers and landowners. CUB/EDF assert this "nuanced" study of DRIPE led the Vermont PSB to reverse its previous view, and include 50% of DRIPE into the cost-benefit analysis. CUB/EDF claim while Staff may be correct in objecting to NRDC's specific calculation model for DRIPE, they are wrong in rejecting any use of DRIPE. CUB and EDF agree with NRDC and the IPA that an appropriate DRIPE calculation should be included in the TRC. (CUB/EDF Reply at 8-9)

CUB/EDF say NRDC and the IPA appear to disagree on how to move forward on how to quantify values for DRIPE, NEBs and line losses. NRDC asserts the SAG is not the appropriate forum for examining the utilities' inputs used for Section 16-111.5B TRC calculations. The IPA suggests that changes to the way the TRC is calculated may be more "effectively implemented" by the broader group consensus which might be achieved through SAG discussion. CUB and EDF agree with the IPA that the SAG would be the appropriate venue for this discussion provided the SAG be given clear direction on the objective of the discussions, namely that it is to settle on quantifiable methods for valuing all three categories of benefits, and a clear deadline by which those discussions must be completed and the resulting methods filed with the Commission and IPA. (CUB/EDF Reply at 9)

8. The AG's Position

ComEd in its Response to Objections takes issue with Staff's proposal to consider net benefits for purposes of ranking potentially competing IPA program bids ComEd argues that Section 16-111.5B only refers to the Total Resource Cost test as being a measure of the overall benefit-to-cost ratio, and that all programs with a ratio higher than 1.0 pass the TRC test. ComEd goes so far as to state that the TRC test was "never intended nor suited for the measurement of net benefits." The AG claims ComEd is simply incorrect in this view. The AG asserts it is the explicit purpose of the TRC test to quantify net benefits. The AG says while the statutory TRC definition in Section 1-10 of the IPA Act refers only to the benefit-cost ratio, this ratio is simply shorthand for determining whether net benefits are positive or negative. The AG contends any benefit-cost ratio greater than 1.0 means there are positive net benefits, while a ratio lower than 1.0 means there are negative net benefits and that the overall economy (and ratepayers) would not be improved by pursuit of that activity or program. The AG says ComEd is correct that the bar for whether a program can be presented to the IPA is that it must have a benefit-cost ratio of at least 1.0. The AG asserts, that is simply the minimum standard for presentation, and really just another way of saying the program must produce net benefits for Illinois. (AG Reply at 2-3)

In the AG's view, what really matters to society and the Illinois economy is the magnitude of the net benefits that will accrue. The AG states while a prerequisite for adopting a program is that it must have some positive net benefits, the issue in question is how competing programs should be evaluated and compared. For this secondary purpose, the AG says economic theory is unambiguous. The AG argues the larger the net benefits the better, even if the benefit-cost ratio is lower. (AG Reply at 3)

ComEd further argues that because customer incentives are not included in a TRC test that it is somehow "distorting" the calculation of net benefits. The AG claims that statement is both misleading and incorrect. The AG says because the TRC test measures cost-effectiveness and net benefits from a societal perspective, transfer payments that simply shift funds from one party to another do not affect the resulting net benefits or benefit-cost ratio. If one party loses a dollar and the other party gains a dollar, no actual net benefits or costs to society are incurred. The AG states for this

reason, the level of customer rebates does not affect the outcome of the TRC test. The AG contends it is somewhat misleading to state that the TRC test does not include incentives, thereby implying that somehow the full cost of installing efficiency measures is not accounted for and recognized. (AG Reply at 3)

The AG says in actual practice, the costs in any TRC test include the full incremental installed measure costs of the efficiency measures, which is made up of two separate components of cost: the customer rebate (paid by all ratepayers) and the customer's direct individual contribution to the measure installation. According to the AG, both these cost components are included in the TRC test. The AG claims the fact that when the former goes up the latter goes down by the same amount is not the equivalent of simply omitting a cost. The AG believes ComEd's rationale for opposing Staff's proposal should be rejected. (AG Reply at 3-4)

In their respective Responses, both ComEd and Staff argue against NRDC's proposal to include DRIPE in TRC cost-effectiveness analysis. Their primary argument is that DRIPE reflects transfer payments between energy producers and consumers, and are not related to actual societal economic impacts. The AG contends ComEd and Staff are simply wrong in their view that DRIPE is simply related to transfer payments. The AG says this view ignores the existing market-based economic structure, and is inconsistent with how Illinois quantifies all other costs and benefits in the TRC calculation. (AG Reply at 4)

According to the AG, ComEd misinterprets economic theory and the meaning of the TRC test in its stated objections to a DRIPE recognition. The AG says ComEd makes a distinction between the SCT and the TRC test. It argues that the SCT must not include transfer payments, but that the TRC does. The AG believes it is important to note that both of these tests consider benefits and costs from a societal perspective that is indifferent to issues of distributional equity (i.e., who benefits and who loses), and therefore should exclude transfer payments that do not reflect real net economic impacts. The AG finds it ironic ComEd's statement is in direct contradiction to ComEd's own previous point that customer rebates do not impact the TRC test result because they are transfer payments. More important to the AG, ComEd is omitting the fact that in some jurisdictions (including Illinois), the TRC test is focused only on the benefits and costs to ratepayers within the Commission's jurisdiction, while the SCT at times take a broader view of all of society (globally or nationally) regardless of the jurisdiction. (AG Reply at 5)

ComEd's Response further argues that federal tax credits are an applicable benefit under the TRC, but represent a transfer of wealth between taxpayers and society and are therefore ignored under the SCT test. The AG believes ComEd misses the relevant point and seems to argue for inclusion of DRIPE in the TRC, not against it. The AG says federal tax credits are treated as applicable benefits to Illinois because these transfers largely come from outside Illinois directly to Illinois ratepayers. The AG says ComEd's comments affirm that tax benefits coming from outside Illinois can and should be counted as a benefit to Illinois. The AG claims ComEd takes the opposite

approach when considering DRIPE and suggests that this is simply a transfer payment and therefore cannot be included as a benefit under the TRC. The AG asserts ComEd must acknowledge that much of the natural gas production ultimately serving Illinois, and the electric power provided by PJM and MISO, is supplied by corporations outside of Illinois. Even when an energy producer is a corporation located in Illinois, the AG claims it is likely the majority of its shareholders benefiting from excess profits reside outside the State. The AG contends even if one considered DRIPE a transfer payment, which the AG believes it is not, ComEd's own argument would support its inclusion in the TRC test. In other words, DRIPE could be viewed as similar to federal tax benefits. (AG Reply at 5-6)

Staff argues that DRIPE should be considered a transfer payment because if retail energy prices drop, the consumer benefit is simply offset by a loss of profits to suppliers. Staff goes so far as to state that this occurs "without any corresponding decrease in production costs." The AG maintains a larger share of independent gas and electric suppliers come from outside of the Commission's jurisdiction. According to the AG, even if DRIPE were a transfer payment on a national scale, ComEd's argument about federal tax benefits would result in DRIPE being included in the TRC as a benefit to Illinois ratepayers. (AG Reply at 6)

The AG argues that DRIPE does not amount to a transfer payment. Contrary to Staff's position that energy efficiency produces no decrease in production costs, the AG says it is precisely because there is a decrease in production costs on the margin that prices drop from lowered demand. The AG says free markets reach equilibrium prices by a matching of supply and demand. The AG states that as demand increases relative to supply, prices rise because society now has to increase supply by drawing on more expensive resources that would not be offered at the lower price. These are real societal costs on the margin. Conversely, when demand decreases, the AG says society no longer needs to rely on these most expensive marginal resources, which puts downward pressure on prices. The AG contends these phenomena are the reason that price effects exists in any competitive market. (AG Reply at 6)

According to the AG, it is true that a low cost energy producer that was already offering supply can make enhanced profits when the market price rises. For example, the AG says a hydro-electric plant owner who could sell power for 2 cents/kWh will sell into the market whether they earn 4 cents or 6 cents, with higher profits under the latter scenario. The AG says the reason prices rise is because society needs to use these more expensive (6 cent/kwh) resources that set the market clearing price on the margin. In market economies, profits are a necessary component of the market, and legitimate costs. In the long term, with well-functioning competitive markets, the AG asserts profits should eventually reach reasonable but not excessive levels. (AG Reply at 7)

The AG contends ComEd's and Staff's arguments turn on its head all Illinois efficiency economic analysis related to the TRC. The AG states that when gas supply boomed in recent years relative to demand, Illinois experienced significant declines in gas and electric avoided costs. The AG says these lower costs where promptly

adopted by the utilities for purposes of analyzing efficiency programs. Effectively, the AG claims ratepayers benefitted from these lower market prices, but some existing producers lost profits as the energy clearing price dropped. According to the AG, this was a direct result of supply increasing more than demand, and is based on the same fundamental mechanism that drives DRIPE. Under ComEd's and Staff's argument, the AG claims one could never adopt these lower avoided costs because they simply amounted to transfer payments from producers to energy consumers. (AG Reply at 7)

It is the AG's position that when screening efficiency measures for cost-effectiveness, evaluators use best estimates of current market prices for the measures. The AG says these prices include profit to manufacturers, distributors, and contractors, and can and do fluctuate based on supply and demand. If there is a shortage of a particular efficiency product or a sudden surge in demand, the AG says the price can be driven up and an existing low cost supplier may make greater profits. The AG asserts all Illinois cost-effectiveness economic analyses still rely on actual prevailing market prices to value resources in our economy. The AG argues reasonable profits are a cost of doing business, and prices are set based on supply and demand reaching an equilibrium. The AG says that occurs by drawing on the next most costly supply resource necessary to meet demand. In the AG's view, while it is true that in the short term, we are simply shifting some value between a "producer surplus" and "consumer surplus," this is how all other efficiency program cost-effectiveness analysis is now performed in Illinois. The AG suggests the real benefit to society is a fraction of the full DRIPE based on no longer relying on the most expensive resources, with the remaining portion a short term transfer. The AG believes that to reject DRIPE for this reason would require a complete reconsideration of how Illinois parties currently estimate avoided costs, efficiency measure costs, and efficiency program implementation contractor costs, all of which include some profit and rely on prevailing market prices for valuation. The AG claims this view is reinforced by a recent paper presented at the American Council for an Energy Efficient Economy's Summer Study. The AG recommends Illinois join in these states that have recognized DRIPE as a measureable benefit. (AG Reply at 7-8)

ComEd also seems to argue that because DRIPE can be large, "as much as 40% of the avoided costs for a 15-year measure life," the Commission should reject NRDC's proposal. The AG says ComEd also suggests that NRDC's position is "result driven" because adding DRIPE would help programs that are currently estimated to have low TRC benefit-cost ratios to pass the TRC Test. In the AG's view, it is because DRIPE is so substantial that it is critical the Commission ensure that these real benefits to Illinois ratepayers are properly recognized. The AG claims to suggest the Commission reject DRIPE because it can make a significant difference is illogical, and simply highlights the fact that Illinois is currently substantially undervaluing energy efficiency. In the AG's view, to suggest that NRDC is "result driven" seems to imply they are simply trying to get failing programs to pass. The AG argues NRDC is proposing that all real and quantifiable benefits be counted, as directed by the statute. The AG says the Commission, too, must ensure that energy efficiency programs are evaluated fairly, recognizing all measureable benefits, to ensure that all cost-effective

programs are included within the IPA's portfolio. The AG encourages the Commission to Order that a best estimate of DRIPE be included in all future analyses of both electric and gas TRC screening, and direct the SAG to resolve what that best estimate should be for Illinois based on existing literature and/or actual DRIPE studies. (AG Reply at 9)

The AG says non-energy benefits refer to benefits that result from efficiency programs beyond those that come from direct reductions in energy consumption. The AG also says many efficiency measures are also better, higher quality and more reliable equipment and as a result consumers can benefit from reduced maintenance costs. According to the AG, industrial process efficiency improvements often save customers additional money on things like reduced water or feedstock consumption, reduced waste generation, and improvements in productivity and product quality. The AG says there are also significant but difficult to quantify "intangible" non-energy benefits, such as improved health from a cleaner environment. The AG believes the issue is identifying those direct NEBS that can be directly quantified. The AG claims other intangible NEBS are often thought of as externalities, and are not being proposed for explicit inclusion in the TRC test. (AG Reply at 9-10)

ComEd takes issue with NRDC's proposal to use a quantified estimate of NEBS and to include these in the TRC test. ComEd notes that Ameren is already using a 10% adder as a default placeholder value in its TRC calculation. The AG says NRDC provides evidence that often NEBS can be substantially higher than 10% of avoided costs, and that efforts should be made to more accurately estimate a NEBS adder. The AG supports this recommendation. (AG Reply at 10)

NRDC references some NEBS estimates from other jurisdictions. The AG says its expert witness, Philip Mosenthal, has done extensive work on energy efficiency in Massachusetts, the state ranked the top in statewide energy efficiency achievements for the past four years by the American Council for an Energy Efficient Economy. As an example of how significant NEBS can be, the AG says Massachusetts estimated in 2012 that fully 26% of its electric avoided cost benefits from its entire efficiency portfolio resulted from NEBS. The AG indicates this is more than two-and-a-half-times larger on a percentage basis than the Illinois 10% default value. (AG Reply at 10)

The AG says Massachusetts recognizes and includes DRIPE in its avoided costs calculation, and in general has significantly higher electric avoided costs than either ComEd or Ameren. The AG states that removing just the DRIPE component, but still using Massachusetts' much higher electric avoided costs, NEBS accounted for 34% of avoided costs in 2012 over its entire portfolio. The AG asserts that for low income programs specifically (where NEBS can be especially significant), NEBS accounted for 119% of total electric avoided costs and 152% of electric avoided costs not including DRIPE. The AG says applying these same NEBS to Illinois' calculated avoided costs would result in significantly higher percentages. The AG claims this is because Illinois avoided costs (the denominator in the TRC calculation) are significantly lower than in Massachusetts, while the actual NEBS enjoyed by customers (the numerator in the

TRC calculation) would likely be similar. This data shows that NEBS can be very significant, and a very important component of benefits. (AG Reply at 11)

The AG supports inclusion of best estimates of NEBS in TRC screening, as they are real benefits to society, and can be quantified reasonably. The AG suggests that if desired, Illinois could engage in specific NEBS studies to estimate their value. The AG says Massachusetts and other states have done much of this research in recent years, and it believes a reasonable and credible quantification can be made based on existing literature. (AG Reply at 11)

The AG encourages the Commission to Order that a best estimate of NEBS be included in all future analyses of both electric and gas TRC screening, and direct the SAG to resolve what that best estimate for Illinois should be based on existing literature and/or actual NEBS studies and analysis. (AG Reply at 11)

NRDC proposes that marginal line losses rather than average line losses be used when screening efficiency programs under the TRC test. ComEd agrees with NRDC, and confirms that it already uses marginal values. To date Ameren has used only average line losses. Because line losses are directly related to the loading on the transmission and distribution wires and transformers, the AG says marginal line losses are significantly higher than average losses calculated based on all power delivered annually. The AG claims this fact is based on simple physics, and is not in dispute nor controversial. (AG Reply at 12)

The AG says because by definition all impacts from efficiency programs reduce hourly loads “on the margin” for any given hour, they clearly are triggering line losses commensurate with the marginal line loss rate, not the average. The AG supports use of marginal line losses in all efficiency program cost-effectiveness analyses as correct, quantifiable, and required for accurate estimates of benefits. The AG asserts that to use average line losses is simply to directly and intentionally underestimate the benefits of efficiency. The AG believes the Commission should order all Illinois cost-effectiveness efficiency analysis by any party to incorporate best estimates of marginal line losses. (AG Reply at 12)

In its Response, NRDC discusses Ameren’s objection to the Commission “expressly” encouraging utilities to engage stakeholders in review of the third party IPA bids. Ameren states that the current models employed by the respective utilities already include stakeholder review. The AG says Ameren failed to involve stakeholders in a meaningful way and to seriously consider their input. While the AG appreciated Ameren’s willingness to permit it to review the bids, it says Ameren provided a very voluminous amount of bid proposals to stakeholders only a week prior to its required submission to the IPA. The AG says Ameren then scheduled a single stakeholder conference call to discuss stakeholder comments. The AG says its consultant, Philip Mosenthal attended this conference. The AG claims he and other stakeholders raised a number of concerns with Ameren about its cost-effectiveness screening and interpretations of duplicative and competing rules, and suggested some modifications,

only to be informed that because the submittal to IPA was due in a matter of days it was too late for any changes to be considered. The AG asserts that while Ameren did discuss the bids with stakeholders, it was quite clear it was simply presenting information on what it would submit to the IPA, and not actually willing to consider and act on stakeholder input. The AG believes it is important for the Commission to make clear that appropriate stakeholder involvement is required and necessarily means providing all information and soliciting stakeholder input with adequate time for this input to actually be valuable and to influence ultimate decisions. (AG Reply at 12-13)

Staff, in its Brief on Exceptions, argues that the Commission should order the initiation of a docket for purposes of litigating the above-mentioned TRC issues. The AG states that given the Proposed Order's admonition to utilities to reconsider their prior opposition to date to these proposals, there is reason to hope that resolution might be achieved in the SAG process. The AG suggests any consensus positions could be presented to the Commission as a part of the annual presentation of Policy Manual changes – a process that is already underway as a result of Commission orders in all utility and DCEO program administrator three-year plan dockets or, as Staff suggests, as an update to the Illinois Statewide Technical Reference Manual. The AG says whether done within the context of the annual TRM update or Policy Manual process, either approach represents a revision of "policy" that ultimately would be reflected in the Policy Manual. In the AG's view, there is no need to open yet another Commission docket for consideration of issues that may be resolved informally and ultimately approved by the Commission in a final order in existing annual Policy Manual or TRM update proceedings. (AG RBOE at 3)

9. Commission Analysis and Conclusions

NRDC urges the Commission to require the inclusion of marginal line losses, DRIPE, and NEBs when Illinois utilities perform the TRC test to evaluate energy efficiency programs. Portions of this recommendation are supported by ELPC, CUB/EDF, and the AG. Portions of the recommendations are opposed by ComEd, Ameren, and Staff. ComEd, Ameren, and Staff make economic arguments against the NRDC recommendations and ComEd and Staff make legal arguments against portions of NRDC's recommendations.

The IPA believes the best path forward is to conduct workshops that would allow for the proper time and process for considering if any of the proposed TRC changes should be made. While the IPA is sympathetic to NRDC and ELPC's desire for immediate resolution, the IPA believes the record in this proceeding is simply too limited relative to what may be accomplished through more thorough and deliberate consideration. If a workshop does not suffice, the IPA suggests another approach could be for the Commission to open a formal investigation of the TRC methodology, but the IPA does not believe that a formal investigation would be a faster or more efficient way to proceed, and thus continues to recommend a workshop process.

Those parties, along with the IPA, also believe it is premature for the Commission to implement NRDC's recommendations because it could impact parties that are not participating in this proceeding. They believe the Commission should refer the issue to workshops conducted either by Staff or the SAG. NRDC and ELPC believe workshops on these issues would not be productive. They claim the issues have been previously raised in such forums and, for the most part, the utilities are not open to considering their positions.

As an initial matter the Commission notes that it has considered at least some of NRDC's recommendations in previous procurement proceedings and declined to adopt them. A significant problem with procurement proceedings is the expedited schedule combined with a relatively large number of contested issues and parties. This makes it difficult for the Commission to deal with complex economic issues, such as those raised by NRDC. As a result, and because not all potentially affected parties are participating in this proceeding, the Commission must again decline to adopt the NRDC's recommendations. Instead, the Commission finds the IPA's recommendation on these issues to be the most reasonable.

The Commission refers the three issues raised by NRDC to be addressed at workshops conducted by the SAG. In the event the SAG is unable to conduct the workshops, for whatever reason, the Commission directs the Staff to conduct the workshops. Among the broader issues to be explored in the workshops, the Commission specifically directs the parties to address why Ameren does not utilize its best estimate of marginal line losses in place of average line losses, which ComEd already utilizes. Additionally, the parties should address the possibly outdated literature relied upon by ComEd in its opposition to the inclusion of DRIPE in the TRC test. The Commission also finds the AG's arguments regarding the inclusion of DRIPE intriguing. As noted above, procurement proceedings are not the ideal forum for considering complex economic issues and the Commission urges the parties to make serious efforts to reach consensus on at least some of these issues. While the Commission does not wish to open a proceeding for the purpose of addressing possible changes to the TRC test at this time, it may be necessary if the parties are unable to make progress in the workshop forum.

NRDC also argues that Ameren is overstating its overhead or administrative costs as used in the TRC test and notes that ComEd does not use a similar percentage adder when performing the TRC test. Ameren disagrees, while Staff suggests Ameren should not be using any generic adder for all programs as administrative costs are likely to vary by program size type and size. The Commission finds the quality of evidence relating to this issue lacking. No party presented evidence regarding Ameren specific overhead or administrative costs though it is almost certain they exist. To the extent the utilities do not explicitly track this information already, the Commission hereby directs Ameren and ComEd to track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs. The Commission rejects Staff's suggestions that Ameren should use a value of zero for a cost that almost certainly

exists and could probably be estimated with reasonable certainty. As a result, while the Commission must reject NRDC's recommendations on this issue because they are not supported by the record, the Commission directs the parties to address this issue in the workshops discussed above.

According to Staff, the IPA indicates it appreciates that Section 16-111.5B(a)(4) in isolation could be understood to demand a more rigorous evaluation, even justifying the use of evaluative criteria separate from criteria used to evaluate programs under Section 8-103. Staff says the IPA suggests in the procurement plan that a workshop could also consider if the IPA should develop and perform an independent TRC calculation with distinct inputs and assumptions rather than relying on inputs provided by the utilities. (Staff BOE Attachment A at 222) The Commission agrees that this would be a reasonable topic to address in the workshops discussed above.

NRDC recommends that the Commission revise the Plan or otherwise expressly encourage utilities to develop requests for proposals with input from and collaboration with interested stakeholders throughout the process in the review of third party program bids. Ameren adamantly objects claiming such a requirement is unnecessary. In its Response, the IPA supports NRDC's recommendation. ELPC supports NRDC's recommendation and suggests the Commission should direct Ameren to follow the same collaborative bid review approach used by ComEd. Staff supports the ELPC and NRDC recommendations with certain modifications. (Staff BOE Attachment A at 225)

Staff supports the Commission requiring Ameren to submit a confidential utility and stakeholder bid review document with its energy efficiency assessment similar to the one submitted by ComEd but recommends that such utility and stakeholder bid review documents include more detail concerning the rationale for the competing and duplicative determinations as well as the facts considered by the utilities and stakeholders in making those determinations. Staff says all parties appear to agree that the stakeholder reviewers should have no decision-making authority. (Staff BOE Attachment A at 225)

The Commission notes that, to some extent, the schedule for the third party bid process is out of the utilities' control and is somewhat sympathetic to Ameren's argument that it attempts to include interested stakeholders to the extent possible. On the other hand, the complaints regarding Ameren's process and openness to input form interested stakeholders, relative to ComEd's is troubling. While the Commission does not believe it necessary to make a change to the Plan under consideration in this proceeding, the Commission directs Ameren to improve its efforts to include interested stakeholders and give their input more serious consideration when reviewing third party program bids in the future. While the Commission does not wish to initiate a formal proceeding to address this issue at this time, it may be necessary if the issue arises in future procurement proceedings.

Staff objects to the IPA's justification for the recommendations as to which Ameren behavioral program should be included in the plan. Staff's objection has

several parts: first, a request to include in the Plan an alternative expression of the total resources cost test expressed as the difference between costs and benefits rather than as a ratio; second, a discussion of the experience of energy savings and cost effectiveness for home energy reports for Ameren and elsewhere in Illinois; and third, a discussion of whether the two Ameren behavioral programs are "competing" or "duplicative."

The IPA and Ameren do not believe that changes to its Plan are warranted in response to Staff's objections. Ameren states that if both programs were adopted, then the respective programs would be cut in half, assuming either vendor would have an interest in contracting for half of the incentives for which it bid. Ameren believes the correct path is to not have these programs compete at half budget, with increased administrative costs, but rather to have one program, chosen by the Commission, run at full capacity so that the bid savings can be achieved.

The IPA believes pragmatic decisions must be made when there are "duplicative" bids and that information will never be perfect, but a determination must be made. The IPA sympathizes with Staff's concern regarding the implications of not adopting the non-incumbent program with the higher TRC. The IPA says its recommendation between these programs is based on a qualitative consideration of multiple factors. The IPA claims the disconnect between vendor-supplied estimates and evaluated therm savings, along with the inherent uncertainty surrounding vendor-supplied values, underscores the weakness of choosing between the two programs on the basis of their TRCs when the input values are not based on the Technical Reference Manual.

Staff suggests various ways that Ameren and the IPA could work with vendors to refine and coordinate bid responses. The IPA indicates it first saw vendor bid responses as part of Ameren's July 15 filing, but says it is not opposed to a consideration of a more active and earlier role in the bid screening and evaluation process in future years.

The Commission appreciates the efforts of Staff relating to incremental energy issues. Ultimately, the Commission agrees with Ameren that the best result is to not have these programs compete at half budget, with increased administrative costs, but rather to have one program run at full capacity so that the bid savings can most likely be achieved. As a result, the Commission rejects Staff's proposed modifications to the Plan.

The consensus language from the 2014 Section 16-111.5B energy efficiency workshops was submitted by Ameren to the IPA in Ameren's energy efficiency assessment required by Section 16-111.5B (now set forth in Appendix B-2 of the Plan) and the IPA filed the consensus language with its Plan with a recommendation that the Commission adopt it. Staff supports Commission adoption of the consensus language from the 2014 Section 16-111.5B energy efficiency workshops as it will increase transparency and certainty for all parties involved with the Section 16-111.5B energy efficiency programs.

The Commission appreciates the efforts of all parties that worked to reach consensus through the workshops on the complicated Section 16-111.5B energy efficiency issues raised in previous procurement dockets. The Commission hereby adopts the consensus language from the 2014 Section 16-111.5B energy efficiency workshops in order to increase certainty for all parties involved with the Section 16-111.5B energy efficiency programs.

The Commission hereby approves the cost-effective incremental energy efficiency programs recommended by the IPA, except as modified in this conclusion above.

D. Renewable Resources

1. Ameren's Position

Ameren notes that the IPA states that the REC target for total renewables and the subtarget for wind RECs are forecasted to be met during 2015/2016. But the IPA states the solar and distribution generation REC subtargets are not forecast to be met. The IPA therefore recommends conducting a procurement of Solar Renewable Energy Credits using the remaining renewable resources budget for 2015/2016. (Ameren Objections at 4)

Having reviewed the Renewable Portfolio Standard, Ameren believes there is not a clear requirement that REC subtargets must be met in a year where the total REC target has been exceeded. Ameren states that since the total REC target for 2015/2016 has been exceeded with existing contracts, the Commission should clarify whether the IPA should spend the remaining renewable budget funds for a one year SREC procurement. (Ameren Objections at 4-5)

Ameren asserts the phrase "to the extent that it is available" in Section 1-75(c)(1) of the IPA Act could be interpreted to mean "to the extent that subtarget RECs are available from the market." Ameren says it could also be interpreted to mean "to the extent that total RECs under existing contracts have not been exceeded." (Ameren Objections at 5)

Ameren claims the proposal could result in the expenditure of approximately $3.8 million which would otherwise not be spent. Based on the current forecast, Ameren says such expenditures would increase supply costs to Ameren eligible retail customers by approximately $0.50/MWh. Ameren states that in addition to the cost increase to customers, logic suggests that a one year SREC procurement would not provide an incentive for new construction of solar facilities within Illinois. Ameren suggests the more likely outcome would be a procurement that results in contracts from existing solar facilities. (Ameren Objections at 5)

Ameren says this issue was previously addressed in the 2013/14 Plan where the IPA stated: "on a total portfolio basis, there is no compelling reason to purchase additional renewable resources during the planning horizon, even though there may be dollars 'left over' to spend." (Id., citing Docket No. 12-0544, Order at 51) According to Ameren, the Commission agreed and therefore the IPA did not pursue any additional procurement of REC subtargets for 2013/2014. Ameren claims the circumstances between the two years are similar and therefore Ameren is unaware of any reason why the Commission should be of a different view. (Ameren Objections at 5-6)

Ameren indicates the IPA recommends a procurement of distributed generation RECs using renewable funds previously collected from Ameren real time pricing customers and where these funds are currently held by Ameren in a liability account. The IPA proposes a procurement term of five years with a solicitation date in September 2015. (Ameren Objections at 6)

Ameren does not in principle oppose using the previously collected ACP funds for the procurement of DG RECs; however, Ameren says there is no evidence to suggest the market is mature enough to support the desired procurement. Ameren also says the contract is not yet developed and since the Plan identifies Ameren as the contractual party, the uncertainty surrounding Ameren's administrative and operational responsibilities is also a concern, especially to the extent that such responsibilities could add additional labor and systems costs. (Ameren Objections at 6)

Ameren is of the opinion that the contract terms are critical to the proper functioning of the proposed procurement, as well as administration after execution of the contracts. Ameren says these issues are amplified given that the DG REC market is not yet well defined and many critical issues are still being discussed among interested parties. Ameren says it therefore cannot fully endorse the proposal as currently described because too many uncertainties remain. (Ameren Objections at 6)

Ameren recommends that any Commission approved DG REC procurement in the Plan should recognize that the IPA is simultaneously pursuing a supplemental solar REC procurement (including DG RECs) using up to $30 million from the RERF and where the IPA will act as the contractual counterparty with suppliers. Ameren believes that the proposed DG REC procurement associated with the Plan would benefit all interested parties by stipulating that the IPA is the contractual counterparty with suppliers and not Ameren. Ameren suggests that to compensate the IPA for DG REC expenses under its contract, the Commission would order Ameren to transfer funds to the IPA based on prior Ameren collections from real time pricing customers. Ameren says the Commission would also stipulate that the total dollar value of DG REC contracts would not exceed funds already collected by Ameren as of a certain date, as well as stipulate whether funds would be transferred on a lump sum basis to the IPA or through a contractual arrangement between Ameren and the IPA with a more systematic distribution of funds when supplier invoices are received by the IPA. Ameren proposes for the Commission to stipulate the September DG REC procurement associated with this Plan should be contingent on the June 2015 DG REC portion of the

supplemental solar REC procurement being fully subscribed. Ameren's rationale is that any shortcoming in quantities under the DG REC portion of the proposed supplement solar REC procurement would indicate the market is not fully developed and, therefore, the September 2015 DG REC procurement would not likely result in contracts. (Ameren Objections at 7)

The IPA indicates ELPC and ISEA object to the inclusion of a one year solar REC procurement, citing concerns regarding the funds being paid to existing facilities in other states which would do nothing to incentivize new construction of solar generation in Illinois. Instead, ELPC and ISEA propose the IPA pursue a DG REC procurement using contracts with a five year term. ELPC and ISEA also propose that the IPA pursue incentives such as rebates that contain claw-back provisions to protect against non-delivery and that, to the extent a five year DG REC procurement is not possible in 2015, the IPA should consider carrying forward any unspent renewable budget for use in future years. (Ameren Response at 2)

Ameren states that while it, ELPC and ISEA agree that a one year REC procurement is not justified, they differ in that ELPC and ISEA propose the remaining budget be used for a DG REC procurement in this or in future years. Besides the concern this would add additional cost to customers in a year where the total REC target has been exceeded, Ameren asserts the ELPC and ISEA proposal is not consistent with the IPA Act. (Ameren Response at 2-3)

According to Ameren, the Section 1-56(b) of the IPA Act states that the IPA is to procure DG RECs through multi-year contracts of no less than five years, and shall consist solely of RECs. Ameren says the IPA Act does not intend for renewable funds to be used as rebates based on a promise that RECs would be delivered at a later date. Ameren claims doing so would unfairly transfer risk to eligible retail customers. Ameren states that in all other Ameren contracts (energy, capacity and RECs), payment to suppliers is commensurate when delivery is confirmed. Ameren says specific to RECs, all Ameren contracts authorize payment to suppliers only after certified RECs have been retired on behalf of Ameren and its eligible retail customers. (Ameren Response at 3)

Ameren asserts that Section 1-75(c)(2) of the IPA Act does not sanction or permit the carrying forward of renewable budgets from one year to the next. Ameren says that given the dynamic nature of eligible retail load (i.e. the load will change from year to year and can do so significantly) the statute correctly envisioned that the renewables budgets (and targets) pertain to one year only; it creates a better line of sight. Ameren suggests that even if such a carryover were allowable under a false interpretation of the statute, doing so would bring forth a series of operational and administrative complexities. Ameren also suggests if customers were to be charged for unused renewable budgets in a year, they would be paying for something but getting nothing in return. Ameren says, conversely, if customers were not charged until the year of a future procurement, the accumulation of banked renewable budgets would be incurred by remaining eligible retail customers. Given the dynamic nature of competitive power

supply markets, Ameren claims these customers would not be the same customers from whom the funds were collected. Ameren also says to the extent that customers continue to migrate to ARES, remaining eligible retail customers would be saddled with the burden of incurring all the expense in the year of the procurement. Ameren believes it is unclear how this proposal would impact the methodology by which the ACP rate is calculated since the IPA procurement for eligible retail customers is directly linked to the ACP. Ameren says this would have an impact on all ARES and its customers. (Ameren Response at 3-4)

Ameren states that the statutory REC target for the 2015/2016 planning year has been satisfied with existing contacts. While dollars remain in the budget, Ameren believes a procurement of RECs (solar RECs or DG RECs) is not justified since doing so would unnecessarily increase customer costs and because no clear requirement to do so can be identified under the statute. According to Ameren, the ELPC and ISEA proposals must be evaluated under the requirements of the IPA Act and it is clear that the statute does not sanction or permit these alternatives. Ameren argues that even under an improper interpretation of the statute, considerable operational and administrative questions remain which make approval of the proposal inappropriate. (Ameren Response at 4)

The IPA continues to advocate a one-year SREC procurement which is contrary to the position of Ameren, that a procurement is unnecessary because the total REC target has been exceeded with existing contracts and, therefore, an additional and unnecessary procurement for the SREC subtarget would increase costs to eligible retail customers. Ameren states that the IPA previously recommended against a subtarget procurement in the 2013 Procurement Plan. (See Docket No. 12-0544) The IPA disagrees by stating the current Plan is different because of perceived changes in switching certainty between Docket 12-0544 and the current Plan. The IPA also states that it is confident the RRB is sufficient to support a one-year SREC procurement for 2015/2016. Finally, the IPA states it is a requirement of the statute to procure REC subtargets regardless of whether the total REC target has been exceeded. (Ameren Reply at 1-2)

ELPC echoes much of the sentiment put forth by the IPA. ELPC further states that RRB has “always” been used by the IPA to determine whether subtargets should be pursued. ISEA also reiterates many of the issues discussed by the IPA and ELPC. ISEA states, however, that the proposed one-year SREC procurement should not impact costs to “retail customers” because the RRB represents funds previously collected by Ameren. (Ameren Reply at 2)

Ameren continues to support its position that a one-year SREC procurement is not necessary given that existing contracts cause the total REC target to be exceeded. Ameren says contrary to the statements of ELPC, the IPA has not always used the RRB pertaining to eligible retail customers as the deciding factor regarding a procurement of subtarget quantities. Ameren states that Docket No. 12-0544 recognized that the total

REC target had been exceeded and even though RRB dollars remained, no procurement of subtarget quantities was pursued. (Ameren Reply at 2)

Ameren believes ISEA is incorrect in its assertion that a one-year SREC procurement would not increase costs to eligible retail customers. ISEA has confused the renewable funds Ameren previously collected from customers taking real time pricing supply as compared to the forward looking RRB, which pertains to eligible retail customers. (Ameren Reply at 3)

Ameren says customers taking supply under real time pricing are required to pay for renewables based on the ACP rate. This rate is calculated by Staff based on IPA procurements associated with eligible retail customers. Ameren says it has collected approximately $5.5 million as of May 31, 2014 from real time pricing customers and holds these funds in an account pending future REC procurements by the IPA, Ameren notes the Plan proposes previously collected ACP funds be used for a 2015 DG REC procurement. Regarding the REC requirements for eligible retail customers, Ameren says the statute dictates the methodology by which yearly REC quantities (subdivided into a total REC target and subtargets for wind, solar and DG RECs) and the yearly RRB are calculated. To determine the remaining balance under the RRB, Ameren asserts the REC dollars associated with existing eligible retail contracts are netted against the RRB with the result representing the remaining RRB for each year of the planning horizon. Ameren says the process is similar for the total REC target; the quantity of existing eligible retail contracts is netted against the total REC target with the result being the remaining total REC target for each year of the planning horizon (this same calculation also occurs for yearly subtargets). For 2015, Ameren claims the total REC target and the wind REC subtarget have been exceeded, whereas the solar PV and DG REC subtargets have a balance. Ameren says the RRB shows a balance of approximately $3.8 million. According to Ameren, this balance has not been previously collected by Ameren and would only be charged to eligible retail customers if the IPA pursued a procurement of one-year SRECs as proposed for 2015/2016 (or an alternate subtarget procurement in 2015/2016 like that proposed by ELPC and ISEA). Ameren asserts that, only after contracts were executed and RECs were retired consistent with contract terms would Ameren pay suppliers and then subsequently recover costs from eligible retail customers. Ameren concludes that an additional procurement of one-year SRECs (or any RECs for that matter) by the IPA for 2015/2016 would result in additional costs to eligible retail customers. (Ameren Reply at 3-4)

Regarding the statutory argument put forth by those opposed to the position that a one-year SREC procurement should not be pursued, Ameren disagrees that subtargets represent clear requirements when the total REC target has been exceeded. Furthermore, Ameren contends that the current circumstances in this Plan are similar to those seen in Docket No. 12-0544. Ameren agrees with ComEd that in Docket No. 12-0544, the IPA characterized these subtargets as aspirational goals, a determination in which the Commission concurred. Ameren believes the position of those advocating a one-year SREC procurement is akin to spending money just because it is available. Ameren says that since the statute does not provide a clear requirement that subtargets

be procured under the current circumstances, Ameren believes the benefit should accrue to customers in the form of cost savings. (Ameren Reply at 4)

Ameren finds it curious that the IPA, ELPC and ISEA all argue that subtargets are statutory requirements, however, collectively they have offered two different proposals which satisfy only one of the two subtarget requirements, which only serves to place in doubt the validity of the their claims. The IPA proposes a one-year SREC procurement for eligible retail customers with no procurement for DG RECs. The rationale for not pursuing a DG REC procurement is that changing load requirements could result in a future RRB being exceeded which would lead to curtailment of the existing Long Term Purchase Power Agreements from 2010. ELPC and ISEA propose a five-year DG REC procurement for eligible retail customers with no procurement for one-year SRECs. The rationale for not pursuing a one-year SREC procurement is that it does not represent a good use of the RRB, and a better use of RRB should be for DG RECs which they believe would entice new construction, especially in Illinois. While both proposals are based on a perception of risks and rewards, Ameren claims that they do not meet the same statutory criteria used by IPA, ELPC and ISEA when objecting to the proposal of Ameren. (Ameren Reply at 4-5)

Regarding the IPA's implication that switching has become more certain between now and a couple of years ago, Ameren believes that considerable switching uncertainty remains. This is evidenced in the differences between the base low and high forecast scenarios for the Renewable Portfolio Standard. Ameren argues that contrary to the assertion by the IPA, that uncertainty is applicable only to the mid-term and beyond, uncertainty applies to the short-term as well. Ameren says the low RPS forecast scenario has a 2015/2016 RRB of $8.7 million and existing contracts are worth $9.2 million. In other words, the low RPS forecast scenario suggests deviations in future switching when compared to the base RPS forecast could cause the RRB to be exceeded in 2015/2016 through existing contracts and without consideration for incremental contracts associated with the proposed one-year SREC procurement (or any other incremental REC procurement). Ameren is not suggesting that the low RPS forecast scenario should be used in determining IPA procurement quantities. Ameren says the statute is clear that the base RPS forecast should be used for procurement purposes and this forecast should be forward looking based on the best information available at the time of forecast development. Ameren's point is that uncertainty surrounding switching is one of the considerations as to whether subtargets should be pursued. Ameren contends that to the extent that a one-year SREC procurement is implemented and switching is higher than the base forecast, remaining eligible retail customers would bear a larger share of the incremental cost of the proposed one-year SREC procurement. (Ameren Reply at 5-6)

Ameren says the total REC target for eligible retail customers has been exceeded with existing contracts. Although SREC and DG REC subtargets remain, Ameren claims, the statute does not require the IPA to pursue a one-year SREC procurement. Ameren says the IPA and Commission reached this same conclusion in Docket No. 12-0544 and this prior decision is instructive to the current scenario.

Ameren asserts that if the IPA were to pursue a one-year SREC procurement for 2015/2016, costs to eligible retail customer would increase and the impact to remaining eligible retail customers could be magnified if switching deviates from the base forecast. Ameren concludes that a one-year SREC procurement should not be pursued. (Ameren Reply at 6)

ELPC and ISEA responded to a brief statement by Ameren that the proposed one-year SREC procurement, which Ameren opposes, was unlikely to create new construction within Illinois. Ameren states that it is not advocating any procurement design that favors new versus existing RECs. Ameren says several parties correctly identified the statutory basis that makes clear such a procurement design should not be pursued. Ameren agrees with such sentiments. Ameren says the intent of its comment was to point out to the extent new construction is one of the considerations pertaining to procurement; a one-year SREC procurement is unlikely to be successful. The intent of Ameren is not to advocate a procurement design that favors new RECs over existing RECs or vice versa. (Ameren Reply at 6-7)

As an alternative to a one-year SREC procurement for eligible retail customers, ELPC and ISEA advocated in their Objections that the remaining RRB should be used for a DG REC procurement of new facilities with contract terms of five years. If such a procurement was not possible in 2015/2016, ELPC and ISEA advocate carrying forward any remaining RRB for use in future years and/or using up front incentives with claw back provisions which provide protection against non-delivery.

Ameren states that in addition to itself, several parties responded in opposition to the alternative proposal. The primary reasons for opposition included future switching uncertainty which could result in five year contracts exceeding the future RRB and a lack of statutory compliance associated with the proposal. Ameren recommends the Commission reject the proposal. (Ameren Reply at 7)

Ameren opposes the procurement of 2015/2016 SRECs for eligible retail customers. Further, Ameren opposes the alternative proposal associated with new DG RECs. Ameren recommends no procurement of RECs for eligible retail customers in the Plan and associated with the five year planning horizon. (Ameren Reply at 7)

The IPA disagrees with the Ameren's recommendation that ACP funds previously collected by Ameren from real time pricing customers be pooled with IPA funds under the RERF for use in a bundled IPA procurement, which would then result in the IPA being the sole contractual counterparty with suppliers. The IPA suggests a better solution may be a legislative change.

Ameren understands that its proposal could be viewed as a novel interpretation of the PUA with which the Commission would need to concur if it approves Ameren's proposal going forward. Ameren claims the interpretation comports with the plain language of the PUA and Ameren cannot identify any party that would be harmed by pursuing this novel approach. Ameren believes the proposal appears to help all parties

through a simplification of administration, while also creating a cleaner line of sight with potential suppliers. Ameren also suggests the statutory requirements could be addressed via the implementation process where such matters fall under the authority of the IPA and Commission. (Ameren Reply at 8)

Ameren also suggests the PUA's requirements could be satisfied by language in the Request for Proposals, which specifies the procurement is intended to address both the DG REC requirements under RERF and Ameren collected ACP funds. Ameren states that importantly, the IPA contracts could have a mechanism by which RECs are retired in a manner that demonstrates statutory compliance for both RERF and funds collected through Ameren's ACP. Ameren suggests that the IPA could periodically make public the quantity of retired RECS. Regardless of the mechanism used, Ameren says the administrative and operational benefits of combining the funds are significant and the fact that no party is harmed further advocates for implementation of the proposal. (Ameren Reply at 8)

Ameren recognizes the arguments of others that claim to be grounds for rejection of the proposal. For example, ELPC states in reference to ACP funds that the statute is clear "the Agency shall increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year." ELPC argues that this citation makes clear the intent is for the utility to be the contracting entity with the renewable resources provider. Ameren asserts that contrary to ELPC claims, this citation does not provide clear intent because it states the IPA is to increase its spending. Ameren states that the citation says "…renewable energy resources to be procured by the electric utility…," but since the electric utility is prohibited from leading such a procurement, the true meaning of the citation is that the IPA will procure renewable energy resources on behalf of the electric utility. Ameren says taking both phrases of the citation in context, the intention appears to be that the IPA should use ACP funds collected by the electric utility to increase its spending on renewable energy resources and then procure on behalf of the electric utility. In addition, Ameren says Section 1-56 of the IPA Act pertaining to RERF is also instructive when it states that "the Agency shall procure renewable energy resources at least once a year in conjunction with a procurement event for electric utilities to comply with Section 1-75 of the IPA Act and shall, whenever possible, enter into long-term contracts on an annual basis for a portion of the incremental requirement for the given procurement year." Ameren says a key phrase in this citation is that the IPA is to procure using RERF in conjunction with the electric utility ACP requirements under Section 1-75. Ameren indicates that Merriam-Webster on-line dictionary, shows that conjoin means "to join together." In addition, Ameren says the implication of this citation is that the IPA is to enter into contracts under the combined procurement and where no mention is made of the electric utilities entering into such contracts. Ameren believes a thorough review of the pertinent sections of the IPA Act associated with RERF and ACP provides further rationale for adoption of the Ameren proposal that the funds should be pooled in a single IPA procurement and where the IPA is the sole contractual counterparty with suppliers. (Ameren Reply at 8-9)

Ameren believes its proposal has merit in that it simplifies administration and operations while also providing a clearer and less confusing procurement for the IPA and potential suppliers. Ameren says the renewable funds under the jurisdiction of the IPA (RERF) are significantly more when compared to those currently held by Ameren awaiting an IPA procurement (in excess of $128 million RERF vs. about $5.5 million ACP). Ameren suggests combining ACP funds into a single IPA procurement saves all parties time and cost and Ameren is aware of no party that would be harmed. Ameren maintains a thorough review of the statute arguably indicates that its proposal appears to be consistent with the intent of the statute. To the extent that any statutory concerns remain, Ameren suggests they can be resolved through mechanisms addressed in the IPA's contract or through the periodic release of public information from the IPA that demonstrates compliance. Ameren claims these implementation issues fall under the authority of the IPA and Commission. Ameren reiterates its recommendation that the ACP funds be comingled with RERF for purposes of the Supplemental PV Procurement and where the IPA is the sole contractual counterparty with suppliers. (Ameren Reply at 9)

Ameren agrees with ComEd that page 3 of the Plan should more specifically identify the dollars available for a DG REC procurement as of a specified date. Ameren supports the language as provided by ComEd in its Response and where the only edit pertaining to Ameren would be that available funds for Ameren are $5,556,580 as of May 31, 2014 (note that unlike ComEd, no past curtailment of LTPPAs has occurred for Ameren). (Ameren Reply at 14)

2. ComEd's Position

ComEd notes the Plan recommends "a Spring 2015 procurement of SRECs to meet each utility's [ComEd's and Ameren's] PV requirements for the 2015-2016 delivery year." ComEd has no process objections if the IPA proposes to follow the same process as it did in procuring renewable energy credits in 2012. ComEd notes this will result in utility customers paying for more RECs than the amount targeted by Section 1-75(c) of the IPA Act. ComEd believes there is an absence of a legal requirement to meet RPS sub-targets once the overall target has been achieved. In ComEd's view, the cost of the above target RECs and the cost involved in holding a REC procurement event raises the question of why holding such a procurement makes sense for utility customers. (ComEd Objections at 21-22)

ComEd reports the Plan proposes that "utilizing the already collected, and otherwise unspent, hourly [ACP] funds to allow the utilities to meet their [DG] targets would be appropriate to further an aspect of the utilities' RPS obligations." ComEd supports this proposal. Further, with respect to the Plan's proposal to obtain five-year contracts and the uncertainty regarding future funding, ComEd understands that the total amount of DG procured over the full five-year term will be paid for with the amount of hourly ACP funds currently available. ComEd notes the Plan also recommends approval of the first of three options presented in the draft Plan for DG procurement using hourly ACP funds. ComEd supports this proposal, which, of the options, is most

aligned with the requirements of the IPA Act and past practices. Even so, ComEd has identified certain language in the Plan related to the DG procurement that it believes should be clarified to ensure compliance with the requirements of the IPA Act.

ComEd states that with respect to the 1 MW minimum, the IPA Act requires that, "to minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." ComEd also says these "organizations shall administer contracts with individual distributed renewable energy generation device owners." In ComEd's view, these provisions clearly direct the IPA to undertake measures that ensure utilities will not have to administer numerous small contracts, each with different pricing terms. Instead, ComEd says the aggregator would enter into and administer the individual contracts and pricing with the various suppliers being aggregated, and the aggregator would then sign a contract (of greater than 1 MW capacity) with the utility at a single price for the specified amount of MW won. According to ComEd, the aggregator would then distribute the funds to the various suppliers represented by the aggregator. (ComEd Objections at 22-23)

According to ComEd, any contract or contract term between the aggregator and utility that would provide for unit specific pricing or that would be for less than one megawatt in installed capacity would clearly be in conflict with the provisions of Section 1-75(c) of the IPA Act. To ensure the Plan is neither vague nor ambiguous regarding its compliance with these provisions, ComEd identified specific changes to the Plan to provide further clarification. (ComEd Objections at 23 and Appendix A)

ComEd states while the Plan proposes to procure DG RECs through a single procurement, in practice the Plan would create two separate procurements by "procuring on the basis of price within each individual market segment (<25kW, and 25kW to 2 MW)." ComEd believes this process is not only contrary to Section 1-56's single procurement requirement, but also runs afoul of Section 16-111.5(e) of the PUA and Commission practice. ComEd says Section 16-111.5(e) requires that bids be selected "solely on the basis of price," and past Commission practice reflects consistent implementation of a single procurement for all REC types (i.e., wind, solar and other). ComEd says to date, all eligible bidders have been welcomed to participate, and the Procurement Administrator selects the lowest cost RECs available until the overall REC target is met or the budgeted funds are exhausted. Once the target is met at the lowest cost, ComEd says the Procurement Administrator swaps out the highest cost REC selected so far with a higher priced REC of one of the statutorily mandated preferences. This process continues (giving equal weight to all mandated preferences) until these preferences are satisfied or the funds are exhausted. In this way, ComEd claims the Procurement Administrator is able to ensure that the overall renewable target is met and costs to the consumer are kept as low as possible while still achieving statutory preferences to the extent possible. According to ComEd, the Commission has expressly considered and approved this approach regarding preferences and priorities. (ComEd Objections at 23-24, citing Docket No. 07-0528, Order at 61)

ComEd argues applying this law and past practice to the DG procurement contemplated in the Plan, the IPA should conduct a single procurement that includes the entire market segment, which would mean selecting the lowest cost DG RECs until the ComEd DG target of 13,194 RECs is met. Once this target is satisfied, ComEd suggests the Procurement Administrator could then substitute higher cost <25kw RECs until this sub-preference is met or the funds are exhausted. ComEd says it provided changes to the Plan in effort to ensure the DG procurement is consistent with the law, as well as past Commission orders and practice. (ComEd Objections at 24 and Appendix A)

ComEd states that in Docket No. 12-0544, the Commission concluded that "on a total portfolio basis, there is no compelling reason to purchase additional renewable resources during the planning horizon, even though there may be dollars 'left over' to spend." ComEd agrees with Ameren that the Commission should follow its prior order here, which will reduce costs borne by customers and render moot the issues raised by ELPC and ISEA. (ComEd Response at 9)

ComEd says like Docket No. 12-0544, the overall renewable energy resources target for the planning horizon at issue in this docket (2015-2016) is already met. ComEd adds that unlike Docket No. 12-0544, the IPA proposes to nevertheless procure additional renewable energy resources using "available" funding for the purpose of achieving certain statutory "sub-targets" (or preferences) for particular types of resources. Specifically, the Plan seeks to procure SRECs to achieve these sub-targets. ComEd argues that because the overall renewable energy resources target will already be achieved this incremental SREC procurement would result in reductions that have no bearing on the already-achieved goal. ComEd says that in Docket No. 12-0544, the IPA characterized these sub-targets as aspirational goals, a determination in which the Commission concurred. (ComEd Response at 9-10)

ComEd argues that given that no legal requirement compels additional procurement above the overall renewable energy resources target to achieve sub-targets, customers should not be required to fund an unnecessary SREC procurement. ComEd says while it is true that some additional funds remain after calculating the 2.015% rate cap under Section 1-75(c)(2) of the IPA Act, this does not mean that these funds must be spent. According to ComEd, the intent and thrust of the Renewable Portfolio Standard is to achieve the overall annual renewable energy goal, taking into account the achievement of the sub-targets "[t]o the extent that it is available." ComEd says while the 2.015% rate cap sets a limit on the spending for renewables, no mandate exists requiring spending up to the cap. In ComEd's view, if the goals can be achieved under the rate cap, customers should benefit from these lower procurement prices. ComEd contends that because this SREC procurement would only apply to the utilities' eligible retail customers, it is particularly unfair that they should shoulder the costs to procure above the statutory target of 10% while RES customers do not share the same burden. (ComEd Response at 10)

ComEd believes ELPC's and ISEA's dissatisfaction with the proposed SREC procurement and introduction of additional complications lend further support to the outcome proposed by Ameren and ComEd. ComEd says while its Objections note its agreement with the proposed one-year SREC contracts should the procurement take place, ELPC and ISEA complain that the SREC contracts should be for a minimum of five years. ComEd believes the one-year contract horizon prudently reflects the uncertainty associated with predicting the level of funding that might be available to purchase SRECs beyond the next year due to ongoing switching by customers through (and independent of) municipal aggregation programs. (ComEd Response at 10-11)

ComEd asserts ELPC's and ISEA's proposals offer no viable solution to the switching uncertainty. ComEd says at most, they suggest the Commission should somehow have "ComEd and Ameren escrow the portion of this year's RRB necessary to cover future contractual payments, instead of relying on future year budgets." In ComEd's view, the proposed shifting of dollars to future years suggests that renewables spending in a future year would exceed the 2.015% cap, thus violating the statutory requirement. ComEd notes neither ELPC nor ISEA cites any statutory authority for this escrow requirement, and ISEA notes that "[i]t is uncertain if this requires future legislative measures." ComEd asserts it is clear that the largely undeveloped escrow proposal cannot be squared with the statutory framework or otherwise overcome the switching uncertainty necessitating one-year SREC contracts. (ComEd Response at 11)

ComEd believes that to the extent ISEA's and ELPC's proposals would require or favor purchase of SRECs only from new facilities, they should be rejected. ComEd says neither ELPC nor ISEA cites any statutory authority for this proposal and claims no such preference exists in Section 1-75(c)(1) of the IPA Act. ComEd asserts this proposal would unfairly discriminate against suppliers that took the initiative and risk to build a merchant or partially merchant facility with the understanding that they would be able to compete for future utility renewable energy resource spending. (ComEd Response at 12)

Following its review of the Objections and the complaints raised by various parties, ComEd has concluded that too many issues have been raised to continue endorsing adoption of the original proposal regarding DG procurement. ComEd shares Ameren's concerns regarding the uncertainty surrounding administrative and operational responsibilities of distributed generation contracts that could result from the proposed use of hourly ACP funds. ComEd suggests that although ELPC claims the proposal is already too complicated, it nevertheless proposes to increase the complexity of DG procurement by further subdividing the DG suppliers. ComEd says ISEA similarly proposes additional subdivisions. ComEd maintains that these subdivisions are contrary to the law and past Commission practice, and accordingly should be rejected. ComEd says ELPC and ISEA also oppose imposition of the credit requirement, which is contrary to well-established credit practices. (ComEd Response at 12-13)

If the Commission chooses to move forward with the DG procurement, ComEd agrees with Ameren that the process could be streamlined, and efficiencies gained, if the IPA were to become the counterparty to the contracts. ComEd notes that the IPA will already be required to sign and administer the contracts for the Supplemental Solar REC procurement to be conducted under Section 1-56(i) of the IPA Act. As a result, ComEd believes it would be far more efficient and cost effective to have the IPA also be the counterparty for the contracts that result from the hourly ACP procurement. ComEd says it would grant the IPA greater flexibility to ensure consistency between the two processes and perhaps even facilitate a combining of the procurements to further reduce costs. ComEd states that if directed by the Commission's Order, it would transfer the hourly ACP funds collected between June 1, 2013 and May 31, 2014, to the IPA to compensate it for the procured hourly ACP RECs. (ComEd Response at 13)

While ComEd agrees with the RS that the Plan should be clarified regarding exactly which hourly ACP funds may be used to procure distributed generation RECs, ComEd believes the language proposed by the RS misunderstands the law and reaches an incorrect result. ComEd says the Plan identifies the correct amount of hourly ACP funds available to purchase DG RECs, but would benefit from refinements to the language on page 3 of the Plan. ComEd identifies the hourly ACP funds that have been collected and the planning year for which they are designated to be used, as well as proposes clarifying language for the Plan. (ComEd Response at 13-14)

ComEd states that as of May 31, 2013, ComEd had $4,099,937 of hourly ACP funds, which were allocated to the suppliers using the annual contract value method. ComEd says these are the funds that are available for the purchase of the 2014/2015 curtailed RECs pursuant to the IPA Act. ComEd adds that any surplus of these funds may not be known with certainty until August 20, 2015, for inclusion in a future Procurement Plan. (ComEd Response at 14)

ComEd indicates that as of May 31, 2014, ComEd had $7,842,658 of hourly ACP funds, excluding the $4,099,937 previously collected hourly ACP funds being used for the 2014/2015 curtailed RECs, that could be used for the purchase of the 2015/16 curtailed RECs, if needed. Because the current load forecast indicates that a curtailment will not be needed, ComEd says the hourly ACP funds balance as of May 31, 2014 could be used for distributed generation REC purchases as proposed by the IPA. ComEd states that the Plan already identifies the $7,842,658 of hourly ACP funds on page 104. (ComEd Response at 14)

ComEd provides specific language to modify page 3 of the Plan intended to clarify the plan and which ComEd claims is consistent with the Plan, past Commission orders and the law. (ComEd Response at 14-15)

ComEd says the RS requests that their contracts with ComEd be changed to extend the delivery window for curtailed RECs to their benefit. ComEd argues that not only is this change inappropriate, the RS cites no authority in support of its proposal

and, absent some showing that the contract is exempt from constitutional prohibitions regarding the State's interference or impairment of contracts. (ComEd Response at 21)

ComEd states that it and the members of the RS entered into contracts for ComEd to purchase RECs curtailed under the LTPPAs. ComEd says the contract form was developed with input from the IPA, Staff, and the Procurement Monitor, and was reviewed and agreed to by Staff and the IPA. ComEd adds that each contract was signed by the supplier, and each contract clearly states that the vintages of RECs that will be accepted are those that are curtailed between June 1, 2014, and May 31, 2015. According to ComEd, the terms are clear, unambiguous, and subject to only one interpretation, and the RS does not claim otherwise. (ComEd Response at 21)

In ComEd's view, the issue at hand is simpler than that presented by RS member FPL Energy Illinois Wind, LLC ("FPL"). ComEd claims the RS' proposal is based solely on a desire to avoid a modest performance requirement in the contract to which they agreed. ComEd says the allowable RECs that can be delivered under the curtailment agreement are equal to the units of output for the June 1, 2014-May 31, 2015 period, multiplied by the curtailment percentage. As long as the FPL unit operates at or above the level to which it committed in its original LTPPA contract, ComEd says it will generate enough curtailed RECs to receive its full allotment of hourly ACP funds. ComEd states that if FPL underperforms over that period, it loses the opportunity to sell curtailed RECs in an amount equal to the underperformance. ComEd asserts that other than the lost opportunity to sell curtailed RECs, there is no performance penalty, or even a requirement to deliver, in this contract. (ComEd Response at 21-22)

ComEd maintains that the RS cited no authority supporting its argument that the Commission can unilaterally change the contract between ComEd and FPL, which in ComEd's view, would seemingly disregard core constitutional protections. ComEd contends the RS have identified nothing that warrants the change it proposes. It is ComEd's position that the fully anticipated operation of the contract's modest performance requirement cannot form the basis for any relief. (ComEd Response at 22)

ComEd concludes that a limited, one-year SREC procurement could be conducted without introducing switching risk, and therefore should proceed. While ComEd agrees that load uncertainty should restrict the term of future renewable (and energy) contracts, ComEd notes that the only other parties to support the concept of an SREC procurement disagree with the IPA's proposed one-year SREC procurement. (ComEd Reply at 13-14)

ComEd says ELPC questions whether the proposed one-year procurement is the most prudent course, ISEA continues to strongly oppose the one-year procurement, and NRDC recommends workshops to address the prudence of the one-year procurement. While the IPA concludes that switching uncertainty precludes consideration of SRECs beyond the one-year procurement, ComEd says it fails to further appreciate that "past circumstances are instructive." ComEd claims that far from distancing itself from the past's switching challenges and uncertainty, past experience with switching risk forms

the basis for the IPA's one-year limit, which in turn incites the opposition of those who otherwise would support an SREC procurement for five-year SRECs. In ComEd's view, the Commission should not require eligible retail customers to pay for an unnecessary procurement that is opposed by virtually every party and whose purpose is to achieve aspirational sub-targets. (ComEd Reply at 14)

The IPA observes that ComEd's proposed approach to use the past procurement process "could be a sensible approach to balancing competing statutory directives" and concludes "but not for this procurement." ComEd says the reason given is a concern that the available hourly ACPs could be exhausted prior to the sub-targets having been achieved, which "would result in a procurement exclusively determined on the basis of price." According to ComEd, this is precisely why the past procurement process should be used here for the DG procurement. ComEd contends this process carefully balances price with achievement of the overall target and sub-targets, ensuring customers realize the maximum procurement of clean energy while also achieving sub-targets to the extent possible. (ComEd Reply at 15)

ComEd says that the proposed DG procurement is not a single procurement simply because it is held on a single day. Regardless of whether the procurements occur on the same day or separate days, ComEd says the IPA proposes to evaluate each size and type of generation separately, which is tantamount to holding separate procurements. ComEd believes this process would not maximize customer benefits and should be rejected. (ComEd Reply at 15-16)

With respect to the issue of minimum contract size between the utility and aggregator, ComEd says it is unclear whether the IPA and it ultimately advance different positions. While the IPA seems to oppose ComEd's position regarding contract size, the IPA's Response also states that it "proposes that aggregators may contract with system owners at different REC price points and systems may be selected at different price points, but with a single blended average REC price for an aggregator's contract with ComEd." Assuming this means that the contract between the aggregator and utility reflects a minimum of 1 MW for a single price (derived from "blending"), ComEd claims this is precisely the position it advocated in its Objections and Response. ComEd says the aggregator construct facilitates small contract amounts and varying prices between aggregators and suppliers. (ComEd Reply at 15)

ComEd says that Ameren's proposal to have the IPA become the counterparty to the DG procurement contracts (with the utilities transferring the hourly ACP funds to the IPA) was well-received by several parties, although some expressed a concern that the proposal could not be squared with the statute. While ComEd does not fully understand Staff's and the IPA's legal concerns with this transfer, ComEd suggests an alternative for the parties' consideration. ComEd suggests it and Ameren could simply contract to purchase RECs from the IPA up to the amount available in the hourly ACP funds collected from June 1, 2013 through May 31, 2014. The single price paid under this contract would reflect the total that the IPA would pay to suppliers under its contracts with them. ComEd says this approach would still require the utilities to enter into

contracts to purchase RECs for their customers (thus alleviating concerns about the statutory language), and would also address Ameren's and ComEd's concerns regarding the contract terms with DG suppliers. The utilities' contracts with the IPA would be for a single average price for the number of RECs delivered. (ComEd Reply at 16-17)

ComEd states that the date by which the IPA determines the amount of hourly ACP funds available for the next procurement year has been understood by parties, without issue, for years. ComEd says while it was initially unclear why the RS were advancing an interpretation that contradicted Commission practice, it is clear that this change, coupled with the contract changes proposed in their Exception No. 3, is designed to lay claim to additional hourly ACP funds for the RS, at the expense of other renewable energy resources suppliers. ComEd believes the Proposed Order should not be revised to implement the incorrect change proposed in the RS' Exceptions Nos. 1 and 2. (ComEd RBOE at 15-16)

ComEd says the RS focuses on the following single sentence in the Order on Rehearing in Docket No. 13-0546, which addressed the 2014 Plan: "Assuming a curtailment were declared for a year, the utility's accumulated balance of hourly ACP funds at the start of the year (June 1) would be used to purchase curtailed RECs during the year." ComEd claims Docket No. 13-0546 did not consider the issue raised by the RS here, i.e., the date by which the hourly ACP funds are identified. Rather, ComEd asserts the language cited by the RS came from the proposal in Docket No. 13-0546, which focused on the price paid for curtailed RECs, not on changing the amount of hourly ACP funds to which they had access. ComEd contends this language can be read in harmony with the statutory framework set forth in Section 1-75(c): "the utility's accumulated balance of hourly ACP funds at the start of the year (June 1)" means the balance of hourly ACP funds at the start of the 2014 Plan year (June 2014 - May 2015), which (pursuant to Section 1-75(c)) means the hourly ACP funds collected from June 2012 to May 2013. (ComEd RBOE at 17)

ComEd argues that as a practical matter, the proposal cannot be implemented when the curtailment contingency is fully considered because the funds available for the September 2015 DG REC procurement must first be reduced by any hourly ACP funds needed to complete the purchase of all curtailed 2014 Plan year RECs (June 2014 - May 2015) and all curtailed 2015 Plan year RECs (June 2015 - May 2016), the amount of hourly ACP funding available for the DG procurement would not be certain until August 2016 (if there is a curtailment for the 2015 Plan year), which is nearly one year after the planned DG procurement event. ComEd claims the complexities and timing of this process are due, in large part, to the variable pricing of curtailed RECs that was proposed by the RS in Docket No. 13-0546 and approved therein. If the Commission were to adopt this latest request by the RS, ComEd asserts it would reduce the IPA's ability to optimize its procurements for RECs using hourly ACP funds in future plan years from suppliers other than the Renewables Suppliers. ComEd states that if the RS' contracts have been curtailed, then the amount of the collected hourly ACP funds that remains after satisfying the RS will not be known until after the start of the plan year. (ComEd RBOE at 17-18)

3. ISEA's Position

ISEA objects to the procurement of 1-year RECs despite IPA concerns that issues in past years resulted in a curtailment of RECs and that the uncertainty in load distribution between the electric utilities and ARES will be difficult to manage and predict. ISEA believes the IPA could take a stronger position toward achieving the long term goals of the RPS by initiating smaller contracts with 5-year contracts focusing primarily on new renewable energy assets. (ISEA Objections at 2)

Given the argument in Section 8.3.1 of the Plan and that the Hourly ACP budget will likely be met with existing "non-speculative systems", ISEA recommends that it would be equally safe and logical for the IPA to procure 5-year RECs for new assets for the Current Utility Renewable Resource Supply and that the RRB budget be used to encourage the development of new assets in the 2015-2016 Procurement. (ISEA Objections at 2-3)

If left to just 1-year RECs, ISEA's concern is that the majority of these funds will leave the state to purchase available REC assets across the country. ISEA feels this is not in the best interest of the state and that these dollars, despite any curtailment risks, could be better used in-state to encourage the development of new assets. (ISEA Objections at 3)

ISEA recommends that the IPA conduct a DG procurement that requires a minimum of 5-year contracts, attracting investors and system developers to enter the market and build new systems that will ultimately assist the state in achieving the 2025 year RPS goals. ISEA suggests these 5-year DG REC contracts would follow the same guidelines for new asset development as defined in the Section 1-56(i) for the Special Procurement provision of the IPA Act including any appropriate claw-back provisions for non-performance of those assets. (ISEA Objections at 3)

ISEA recommends that the IPA explore additional methods for ensuring budget stability, including requiring ComEd and Ameren escrow the portion of this year's RRB necessary to cover future contractual payments, instead of relying on future year budgets. ISEA understands this could lead to the procurement of fewer DG RECs using the 2015-2016 funds, but the RECs procured would be linked to the development of new projects, which ISEA claims furthers the state's renewable energy goals and leads to longer-term price stability. ISEA is uncertain if this requires future legislative measures, but ISEA recommends this course be considered for the long term execution of the RPS program through 2025. (ISEA Objections at 3-4)

ISEA says it seeks the creation of a simple, transparent process. ISEA expresses concerns that Option #1 in Section 8.3.2 of the Plan will be cumbersome, confusing and possibly a deterrent to consumers, particularly in the <25kW market. ISEA says theoretically, there could be many bidders awarded RECs for the <25kW

segment. ISEA claims that could have two possible damaging outcomes. (ISEA Objections at 4)

ISEA suggests consumers could be confused about how to select a REC provider. ISEA claims the Illinois power market is incredibly complex for rate payers who must select among nearly 100 suppliers in the market, making grid electricity purchases a confusing and daunting process. Additionally, ISEA says there are a variety of installation companies, each offering a unique level of service, experience or expertise to the market. According to ISEA, this is a non-conventional purchase for most consumers and, therefore, can be intimidating to compare competitors and select appropriately on a technology for which most are unfamiliar. ISEA fears that by adding another complex decision to prospective system owners that many may be overwhelmed and ultimately opt to do nothing. ISEA contends the result would be catastrophic for this new and growing industry, most likely resulting in the loss of projects and long term business stability for installers. (ISEA Objections at 5)

ISEA claims this option has the real potential to limit business opportunities for new installers planning to enter the Illinois market or who may already be installing locally but would not have the ability to meet the 1MW aggregation threshold. ISEA suggests this inability to offer RECs as a service to customers could have a detrimental and devastating impact on these businesses when competing against a firm who is able to contract for RECs directly with system owners, particularly for committed but unbuilt assets. ISEA asserts this provides an undue advantage to some market participants while blocking others' ability to participate. ISEA contends that in a situation where two successful bidders who also have installation capabilities one could have an additional advantage based on the REC price they are able to offer customers. In ISEA's view, the lack of a standard offer for smaller systems becomes a competitive advantage for some, a disadvantage or even barrier for others and yet another point of confusion for buyers. ISEA states that the Illinois solar installation industry is a very young and immature market. ISEA believes it is imperative in these early years of development to encourage new small businesses to enter the market, create jobs, generate demand and establish an expertise that will continue to grow the market as well as push pricing lower through increased economies of scale and competition. (ISEA Objections at 5-6)

ISEA recommends the use of a third-party administrator for systems <25kW and that a standard offer price be given to all small systems. ISEA believes this should at a minimum include systems <25kW and potentially any additional product categories that may be developed. ISEA claims the use of multiple aggregators, each with varying bid quantities and pricing for <25kW and >25kW will not add value to the marketplace and could have a negative impact on the industry. (ISEA Objections at 6)

ISEA says that given the vast differences in development costs and basic economics for systems between 25kW and 2,000kW, it recommends that the IPA consider subcategories within this segment to ensure diversity of awarded projects and broaden opportunities for participation. ISEA recommends two subcategories: one

category for systems between 25kW - 399kW and another category for systems between 400kW - 2,000kW. (ISEA Objections at 6)

According to ISEA, the costs and financing of PV systems vary substantially by system size. ISEA asserts that if the IPA chooses to not develop multiple tiers for projects over 25kW, the likely outcome is that smaller commercial systems will be priced out of the market. ISEA claims a bid that is on the lower end of this market segment spectrum is unlikely to win against a bid for a larger system. ISEA also assumes that REC pricing for the 2,000kW systems will be significantly lower and may not have the desired economic impact for smaller sub-categories given the very different economics between 25kW and 2,000kW. ISEA claims the program will therefore favor large systems and may not yield a diverse development of projects which does not serve the business community. ISEA contends creating subcategories within this market segment gives all projects a chance to compete against projects of similar size and characteristics. ISEA says there is strong support from the solar industry to create 2 or 3 size ranges within the 25kW and 2MW segment. (ISEA Objections at 7)

ISEA claims that in other states that have competitive solicitations, the state programs are typically designed to have multiple tiers within the commercial segment (>25kW). ISEA says New Jersey has two product segments <50kW and 50kW to 2MW while the Connecticut ZREC program separates medium (100-250kW) and large projects (>250kW - 1MW) so that the projects compete only within their segment for program funds. ISEA says the Delaware REC competitive solicitation also has two tiers within its “large” category of 30kW - 2MW. ISEA adds that smaller systems (between 30 to 200kW) and larger systems (between 200kW to 2MW) do not compete against each other for REC contracts. ISEA claims other states such as Massachusetts and New York are creating new incentive programs targeted specifically at increasing small commercial installations to drive economic growth and a variety of benefits that this mid-tier market segment provides. (ISEA Objections at 7-8)

ISEA is concerned that the lack of categorization could have an unintended negative consequence, particularly on systems >25kW but still relatively small. ISEA says Solar Service Inc. has reported that on September 30th it was contacted by a customer following the procurement rule making process. ISEA claims that although the project is nearly ready for permitting, the customer is strongly considering downsizing its 35kW array to <25kW to potentially qualify for a higher REC price. ISEA asserts the customer expressed a valid concern that a 35kW system would be lumped in with what will likely be considerable lower pricing that applies to systems up to 2,000kW. ISEA also says the customer is also considering changing the date of the installation per the definitions of “new” within the Special Procurement on the speculation that these RECs could also yield higher value and have a greater immediate impact on their investment and financing options. ISEA is concerned that there has been an almost immediate and negative impact for both the buyer and installer. ISEA requests that the IPA considers the influence these rules will have on project development and business growth. (ISEA Objections at 8)

In ISEA's view, the credit deposit of $10 per REC in Section 8.3.2.4 of the Plan could create a significant barrier to small local Illinois solar companies and nonprofits seeking to participate as aggregators. ISEA asserts if smaller companies are not able to meet this significant financial benchmark for participation, their existing customers will need to seek contracts with either a nationally established REC aggregators or a national installers who successfully bid into the IPA REC procurement process. ISEA claims this would be confusing and inconvenient to system owners who will then need to shop their systems around to new parties potentially offering different REC prices. (ISEA Objections at 9)

ISEA is uncertain how systems would be identified in the "bid" process if a bidder is not certain on the market price they will be able to offer homeowners. ISEA says it has requested further clarification on the identification of assets and the timing that this information will be released. (ISEA Objections at 9)

ISEA maintains that the inability to sell RECs in the open market could be a competitive disadvantage for solar developers who might be competing with a company that was accepted as an aggregator. ISEA claims for projects under contract but not currently developed, the situation becomes further complicated as this could now lock small businesses out of the market. ISEA says these small local businesses would not be able to compete with companies able to provide RECs as a service to prospective system owners. ISEA asserts that the companies who are able to include the REC purchase in their proposal will show a more attractive payback period. (ISEA Objections at 9-10)

ISEA contends the use of a Program Administrator for systems under 25kw would allow for a more equitable opportunity to all size installers. ISEA claims a program administrator also ensures a more consumer friendly market, a single source and process for system owners, greater transparency and simplicity from which future procurements could be executed and altered. ISEA says using multiple aggregators as a starting point with varying process and pricing will create consumer confusion and has the potential to limit and greatly hamper system purchase decisions and therefore suppress the industries' ability to grow and the IPA's ability to execute a successful REC procurement and drive the 2025 RPS goals. (ISEA Objections at 10)

ISEA notes no speculative bidding will be allowed and projects must be identified in the bid. ISEA complains that the IPA does not say exactly how this will occur which is a concern to ISEA, particularly in the <25kW segment. ISEA claims there are likely some installers in Illinois who have already developed an adequate customer base or could combine forces with other installers to achieve the 1 MW bid minimum. ISEA questions how and when these assets be uniquely identified. ISEA also questions if companies are uncertain that their bid and subsequent pricing will be accepted, how will these companies market to system owners and how a unique list of projects will be presented. (ISEA Objections at 10-11)

ISEA states projects can already be energized or must be energized sometime within the June 2015-May 2016 timeframe. ISEA questions if they do not come online in this timeframe, can contracts either be canceled or reduced by the amount you bid for year 1. (ISEA Objections at 11)

ISEA states there will be 5-year contracts starting immediately (for existing projects) or upon first meter read for projects not yet online. It is unclear to ISEA if the 5-year contract means Procurement Year 2015-Procurement Year 2019, regardless of when the first meter read is (i.e., not-yet-energized systems will have a lower Year 1 REC amount) or if the 5-year contract can bleed into Procurement Year 2020 for systems that come online at the tail end of the allowable timeframe. (ISEA Objections at 11)

ISEA says bidders will give the annual and 5 year total REC amount and price for each project. It is unclear to ISEA if the "annual" REC amount refers to the amount produced during the June-May Procurement Years, and, again, if for systems not-yet-energized that means a lower REC amount for the first procurement year. (ISEA Objections at 11)

ISEA indicates bids will be disqualified if they don't meet the confidential benchmark set by the IPA. ISEA complains there is no explicit distinction if different benchmarks will be used for different size projects, though since these are different "products" this is implied. ISEA also complains of no distinction if different benchmarks will be used for different types of projects (wind, solar, etc.) and that no indication if the disqualification is project-by-project or for an entire bid. (ISEA Objections at 11-12)

Ameren states, "Regarding this proposal, having reviewed the [RPS], there is not a clear requirement that REC subtargets must be met in a year where the total REC target has been exceeded. And since the total REC target for 2015/2016 has been exceeded with existing contracts, the Commission should clarify whether the IPA should spend the remaining renewable budget funds for one year SREC procurement."

According to ISEA, the IPA Act specifically calls out individual targets not only for Renewable Energy collectively by Energy Year ("EY") but each subtarget for Wind (75%), PV (6%) and DG (1%) is also indicated. ISEA says these goals are further identified in subsequent documents including the language for Section 1-56(b) of the IPA Act for the Special Procurement being drafted by the IPA concurrently to the 2015 Regular Procurement Plan. ISEA's interpretation is that the repetition and specificity of these metrics indicate the intention of the General Assembly to meet the broader renewable energy goals as well as each of the additional subtargets annually. (ISEA Response at 2)

Ameren says the phrase "to the extent that it is available" could be interpreted to mean "to the extent that subtarget RECs are available from the market." ISEA avers, however, that it could also be interpreted to mean "to the extent that total RECs under existing contracts have not been exceeded."

ISEA claims that based on the annual increase in goals for each subcategory, it is implied that each goal should be expanded and met to the availability of the market to deliver. ISEA believes if RECs are available at an affordable price below the confidential benchmark for both PV and DG, those requirements should be met annually as proposed by the IPA Act. (ISEA Response at 3)

Ameren notes the proposal could result in the expenditure of approximately $3.8 million which would otherwise not be spent. Based on the current forecast, such expenditures would increase supply costs to Ameren eligible retail customers by approximately $0.50/MWh.

ISEA asserts that the overall objective of annual load forecasting is to define the available resources and corresponding targets for renewable energy procurement and authorize the utility to spend funds previously collected. ISEA believes this purchase should not have an impact on retail supply costs as this fund is already within the utility budget and requirements. Provided the REC price does not exceed the confidential benchmark, ISEA believes this comparison should have no bearing on the purchase of RECs. (ISEA Response at 3-4)

Ameren says that in addition to the cost increase to customers, logic suggests that a one year SREC procurement would not provide an incentive for new construction of solar facilities within Illinois. Instead, the more likely outcome would be a procurement that results in contracts from existing solar facilities.

ISEA agrees that a one year SREC program will not provide an incentive for new construction of solar facilities within Illinois. ISEA says it recommended in Objections that the RRB fund be used instead to procure 5-year contracts for new solar assets in order to continue to grow the DG market and ensure that the RRB fund begin to get on track as forecasts anticipate an ongoing shortage of RECs in this budget category. ISEA believes this will be an important market indicator that will spur investment from solar developers. Alternatively, ISEA would support suggestions regarding the RRB purchase from ELPC in its objections. (ISEA Response at 4-5)

Ameren says that in Docket No. 12-0544 the Commission found the IPA should not pursue any additional procurement of REC subtargets for 2013/2014. Ameren believes the circumstances between the two years are similar and Ameren is unaware of any reason why the Commission should be of a different view.

ISEA argues that this is not a direct and equal comparison to past plan recommendations as the 2013/14 Plan did not include a procurement for conventional energy on behalf of the utilities. In ISEA's view, as the two years are not similar, the precedent should not be applied in this case. (ISEA Response at 5-6)

Ameren says it does not in principle oppose using the previously collected ACP funds for the procurement of DG RECs; however, it says there is no evidence to suggest the market is mature enough to support the desired procurement.

ISEA states that without significant market indicators, the industry will continue at the pace it is developing today. ISEA claims the purpose of the IPA Act is to provide those necessary cues that will bring the necessary interest, investment and the resulting growth desired. (ISEA Response at 6)

ISEA notes that Ameren takes issues with some of the details regarding the process and responsibilities. ISEA supports the suggestion of following the 2015 Special Procurement by naming the contracting parties as the IPA and the aggregators. ISEA also supports the flow of funds that have been described, provided that this is acceptable timing for the IPA to make necessary invoice payments. ISEA believes the IPA should strive, where possible, to pool resources and streamline processes, keeping administrative costs at a minimum and preventing potential market confusion. (ISEA Response at 7-8)

Ameren requests that the 2015 Regular Procurement event currently scheduled for September 2015 be contingent upon fulfillment of the June 2015 Special Procurement Event. ISEA asserts that as the two procurement plans target assets in different stages of development, there is no need to create a contingency between the two. ISEA says the Special Procurement in June 2015 will focus exclusively on new solar assets while the September 2015 Regular Procurement event seeks existing assets making both procurements unique and distinct. ISEA states that both stages of development are important toward the development of achieving the 25% renewable portfolio by 2025 and further delay will risk successful achievement. ISEA claims that although the first year may be challenging, the enactment of a predictable, reliable program will give the industry the necessary triggers to develop solar businesses that will increase the workforce as well as develop solar assets in Illinois and achieve the desired environmental and economic benefits originally intended. (ISEA Response at 8-9)

ComEd states, “As such, any contract or contract term between the aggregator and utility that would provide for unit specific pricing or that would be for less than one megawatt in installed capacity would clearly be in conflict with the provisions of Section 1-75(c) of the IPA Act. To ensure the Plan is neither vague nor ambiguous regarding its compliance with these provisions, ComEd has included changes in the attached redline version of the Plan to provide further clarification.” ComEd further comments that there will in effect be two procurements within one, those <25kW and those >25kW.

ComEd states, “while the Plan proposes to procure DG RECs through a single procurement, in practice the Plan would create two separate procurements by “procuring on the basis of price within each individual market segment (<25kW, and 25kW to 2 MW).” ComEd continues, this process is not only contrary to Section 1-56’s single procurement requirement, but also runs afoul of Section 16-111.5(e) of the PUA

and Commission practice. According to ComEd, 220 ILCS 5/16-111.5(e) requires that bids be selected "solely on the basis of price", and past Commission practice reflects consistent implementation of a single procurement for all REC types (i.e., wind, solar and other).

ISEA believes this change in the procurement process will prevent the significant development of smaller solar installations, particularly those <25kW. ISEA maintains this process could be simplified if the IPA were the contracting party and managed the procurement process. ISEA suggests the Program Administrator would be able to manage the successful handling of a two tiered bidding process which would then be paid for by using the Hourly ACP funds. ISEA says the IPA would then be able to achieve all program goals as stipulated in the IPA Act guidelines and all environmental and economic goals could be achieved as intended. ISEA states that although this differs slightly from conventional procurements, the concurrent Special Procurement process will have similar needs and must therefore be accommodated. (ISEA Response at 10)

ISEA also suggested that the IPA consider a separate Program Manager who could handle the individual contracts for systems <25kW. ISEA asserts that based on observation of the execution of RPS plans in other states, this process has been successful and Illinois could be served to take example from those programs. (ISEA Response at 10-11)

Staff concludes that the General Assembly wanted to continue to utilize the same type of "competitive procurement processes in accordance with the requirements of Section 16-111.5 of the Public Utilities Act" that is required for all other IPA procurements. ISEA argues that by identifying separate and unique goals for <25k and >25kW the General Assembly recognized the unique value each category provides to the market place. ISEA claims other states have shown this to be true both for diverse asset development and economic growth resulting from a growing workforce. ISEA is uncertain if the General Assembly intended the statute to specifically follow previous guidelines and keep specifically to that process or if instead the General Assembly charged the IPA with the responsibility of defining a program that would deliver the intended results. ISEA says the inclusion of these subtargets would suggest instead that broader initiative was intended with the details to be determined in a manner that best suited the needs of solar specific assets. ISEA asserts this market is structured very differently than conventional energy markets and should not be forced into a similar strategy through convenience and routine. ISEA recommends that the IPA plan to seek separate bids be considered for approval. (ISEA Response at 11-12)

ISEA agrees with the original recommendations of the IPA 2015 Procurement Plan to strategically utilize the Hourly ACP funds for procurement strictly for solar given that the delivered wind assets remain above target and the Solar assets are significantly behind. (ISEA Response at 12)

ISEA disagrees with AIC and ComEd that there is no statutory requirement to procure photovoltaic sub-targets of the RPS if the overall REC targets are met for a delivery year. ISEA agrees with ELPC, NRDC and the IPA in their Responses that Section 1-75(c)(1) of the IPA Act states that the subtargets are a minimum mandatory target, not a cap or goal.

ISEA disagrees with ComEd's reading of the Commission's Order in Docket No. 12-0544. ComEd states that the Commission "ultimately concluded" to not purchase additional renewable resources at that time. ISEA says it was the "IPA's view," which was motivated by the IPA's observation that the "costs of conducting a procurement event for a relatively small number of RECs" may not be justified in light of the "exceptionally low" volume of SRECs needed at that time. ISEA asserts the IPA's 2013 plan was developed under different circumstances that do not apply today. ISEA says the IPA clarifies in its Response Comments that there was a "cloud of uncertainty" regarding projected future budgets in 2013. ISEA notes the IPA now is "confident in October 2014 that the renewable resources budget will be sufficient to support a 2015-2016 one-year SREC procurement." ISEA believes that in this case, as in Docket No. 12-0544, the Commission should defer to the IPA's judgment regarding the prudency of procuring solar and distributed generation resources as part of its overall Plan. (ISEA Reply at 2)

AIC, ComEd, Staff and the IPA state that ISEA's proposal to use RRB fund to procure 5-year contracts for new solar assets is not consistent with the IPA Act and exposes the long-term contracts to risk associated with customer migration. While ISEA understands that the IPA cannot procure long-term contracts with the RRB absent legislative action, ISEA maintains that long-term contracts of at least 5 years are necessary in order to spur new solar development in the state. (ISEA Reply at 2)

Staff recommends in its response to objections that if the Commission decides to accept a 5-year SREC procurement, the budget for the new 5-year contracts be limited to one-half the total projected remaining budget available. Staff also recommends that the new 5-year contracts include provisions for curtailment and that the new 5-year contracts would be curtailed prior to curtailing the existing long-term contracts. ISEA supports Staff's proposal if the Commission decides to accept a 5-year SREC procurement from new projects. (ISEA Reply at 2-3)

Staff and IPA object to ISEA's recommendation to use a third Party Administrator and make a standard offer for systems <25 kW. Both the IPA and Staff state that the IPA is not permitted to make a standard offer by law; however, an aggregator could make a standard offer on its own. The IPA agrees that one single aggregator would help reduce consumer confusion; however, the IPA claims "a single aggregator could yield market power and require unreasonable administrative costs."

ISEA acknowledges that the IPA cannot create a standard offer on its own and recommends a competitive bid process for selection of a third Party Administrator based on an established confidential benchmark. ISEA supports the establishment of two

separate budgets - one for system sizes below 25 kW, which would be administered by a third Party Administrator, and a separate budget for system sizes between 25 to 2,000 kW, which would be administered according to the competitive bid process already recommended by IPA. ISEA believes the competitive process for both segments would ensure that a single aggregator would not yield market power. (ISEA Reply at 3)

As to the concern over administrative costs associated with a competitive bid process for choosing a third Party Administrator, ISEA suggests the IPA could require full disclosure of costs and pricing during the bid process to prevent unreasonable administrative costs. ISEA does not believe the process will be burdensome and considers it an appropriate strategy to ensure a more consumer-friendly process that is transparent and simple for solar homeowners and small businesses, which in turn encourages development of assets. (ISEA Reply at 3)

ComEd interpreted the IPA's procurement Plan as proposing two separate procurements: one for systems under 25 kW and another for systems between 25 kW to 2 MW. Staff notes in its Response that if the Commission ultimately approves separate procurements for each of the two system categories, then the Commission must approve separate budgets or authorize the IPA to adopt separate budgets. If the Commission approves separate procurements for each of the two system categories, ISEA seeks clarification on how the separate budgets would be established absent pricing at this stage. (ISEA Reply at 3)

Staff and IPA reject ISEA's proposal to develop system size sub-categories within the 25 kW to 2 MW category. Both the Staff and IPA agree with ISEA that smaller commercial systems within that range will likely be priced out of the market. However, Staff claims that there is no coherent rationale for spending more to purchase from smaller systems within the 25 kW to 2 MW range and that the law explicitly expresses no preference to split systems between 25 kW to 2 MW into two subcategories. The IPA believes that "given the small budget associated with this procurement and the need to cost-effectively meet statutory DG procurement goals," the development of sub-categories is not suitable for this procurement.

While ISEA understands that the law explicitly expresses no preference to ensure that small commercial systems participate, ISEA believes encouraging various market segments is important for market diversity and growth, ratepayer considerations, and grid benefits. ISEA argues that without sub-categories within the 25 kW to 2 MW segment, small businesses in Illinois will effectively be unable to participate in the procurement. ISEA believes this presents a true barrier to entry that singles out a customer class. (ISEA Reply at 4)

ISEA claims small commercial projects are vastly under-represented nationwide despite the enormous potential. ISEA asserts there are difficulties in financing and developing small commercial solar, as transaction costs are nearly the same as 2 MW projects and that many states, including Massachusetts and New York, have acknowledged the need to independently incentivize small commercial projects. ISEA

argues that the incentive programs for those states incorporate specific carve-outs for small commercial projects. (ISEA Reply at 4)

In its Response, the IPA requested an alternative proposal to the proposed credit deposit of $10 per REC. ISEA recommends that the IPA require a credit deposit of $5 per REC for participation. ISEA says it surveyed current members and the consensus was that $5 per REC will not be cost prohibitive for participants. (ISEA Reply at 4-5)

4. The RS' Position

The RS reports that the IPA Plan (i) indicates, based on the utilities' July 2014 load forecasts, that curtailments of the Renewables Suppliers' LTPPAs are unlikely in 2015-2016; (ii) asks the Commission to "pre-approve" curtailments of the LTPPAs if the utilities' March 2015 load forecast updates show that curtailments are needed; and (iii) proposes that the alternative compliance payment funds collected by the utilities from their customers on hourly pricing service ("HACP funds") should be used to fund procurement of RECs from distributed generation resources pursuant to five-year contracts. (RS Objections at 1-2)

The RS indicates its concerns with draft Plan were based on the fact that the IPA was (i) proposing to commit HACP funds, which in the Rehearing Order in Docket 13-0546, the Commission had directed to be used to purchase curtailed LTPPA RECs using the pricing calculation proposed by the Renewables Suppliers, to another use, while (ii) asking the Commission to pre-approve curtailments of the LTPPAs in 2015-2016 if curtailments were shown to be needed based on the utilities' March 2015 load forecasts. The RS says it submitted extensive comments to the IPA regarding this component of the draft IPA Plan. Based on the Executive Summary section of the filed IPA Plan, the RS says the IPA appears to have modified its proposal concerning the DG REC purchases in a way that addresses the RS' concerns that were articulated in its comments on the draft Plan. The RS says the revisions to the Executive Summary from the draft Plan to the filed IPA Plan have not been fully replicated in Section 8, Renewable Resources Availability and Procurement, of the filed IPA Plan. (RS Objections at 2)

So there is no misunderstanding, the RS states what it understands the IPA to be proposing with regard to the proposed procurement of DG RECs:

1. The proposed procurement of DG RECs using the utilities' HACP funds would be held in September 2015 and would be based on HACP funds already collected from customers as of the time of the March 2015 load forecast updates. That is, the DG REC purchases pursuant to five-year contracts would be fully funded from existing, collected HACP funds, and would not be funded by a commitment of HACP funds to be collected prospectively. IPA Plan at 6, item 10, and at 100.

2. The amount of the collected HACP funds that would be available to fund the DG REC purchases would be reduced by (i) the amount of HACP funds needed to

fully purchase all curtailed 2014-2015 LTPPA RECs, at the pricing approved by the Commission in the Docket No. 13-0546 Rehearing Order, and (ii) the amount of HACP funds needed to purchase any curtailed 2015-2016 LTPPA RECs, in the unlikely event that a 2015-2016 LTPPA curtailment is shown to be needed based on the utilities' March 2015 load forecasts. IPA Plan at 3 and 4.

3. If LTPPA curtailments are needed for either utility for 2015-2016, the methodology adopted in the Docket No. 13-0546 Rehearing Order for the calculation of the purchase prices for curtailed LTPPA RECs should be employed. IPA Plan at 103.

The RS states that with one exception, if the three points set forth accurately state the IPA's proposal concerning the proposed procurement of DG RECs pursuant five-year contracts, using HACP funds, then the RS have no objections to this component of the IPA Plan. To the extent that the IPA's proposal deviates from the three points set forth above, then the RS says it objects to this component of the IPA Plan. (RS Objections at 2-3)

The "one exception" to which the RS refers is that the RS objects to and questions the IPA's proposal to fund the DG REC procurement with the HACP funds collected and available (i.e., as reduced to provide for procurement of 2014-2015 and 2015-2016 curtailed LTPPA RECs) as of the time of the utilities' March 2015 load forecast updates. The RS notes the utilities are required by the IPA Act to report their balances of collected HACP funds as of May 31 of each year. The RS also says the collected HACP balances at May 31, 2014 are the funds available for the purchase by ComEd of curtailed 2014-2015 LTPPA RECs. According to the RS, the HACP funds collected as of March 2015 will include the remaining balance of the HACP funds that were collected as of May 31, 2014, which may be needed (for ComEd) to purchase the remaining curtailed 2014-2015 LTPPA RECs. The RS complains the IPA has provided no explanation for basing the DG REC purchases on the amounts of HACP funds collected and available as of March 2015, rather than as of the required reporting date of May 31, 2015. (RS Objections at 3)

In an effort to address the one exception, and for clarity of the IPA's overall proposal regarding the purchase of DG RECs, the RS recommends that item 10 in the IPA's "Action Plan" on page 6 be revised to read as follows:

10. Approve a September 2015 procurement of distributed generation RECs using hourly ACP funds already collected as of May 31, 2015, reduced by:

    (i) for ComEd, the amount of hourly ACP funds needed to complete the purchase of all curtailed 2014-2015 RECs, using the pricing approved in the Docket No. 13-0546 Rehearing Order, and

    (ii) if curtailments of the Long-Term Renewables Power Purchase Agreements are necessary for either utility in 2015-2016, the amount of

> the utility's hourly ACP funds needed to purchase curtailed 2015-2016 REC, using the pricing approved in the Docket No. 13-0546 Rehearing Order.

(RS Objections at 4)

The IPA agrees with the RS' three clarifying points concerning the proposed procurement of Distributed Generation RECs using the utilities' accumulated balances of ACP funds attributable to their sales to hourly pricing customers. Additionally, with respect to point 1, the IPA agrees with the RS that the date for calculation of the balance of available HACP funds for use in purchasing DG RECs should be May 31, 2015, not March 2015 as originally proposed by the IPA. (RS Reply at 1-2)

With these agreements by IPA to the points raised in the RS' Objections concerning the proposed DG REC procurement, the RS believes it and the IPA are in agreement as to the use of HACP funds for the proposed DG REC procurement. The IPA's agreements in its Response resolves the RS' concerns, as expressed in its Objections, with respect to the use of HACP funds for the proposed DG REC procurement. (RS Reply at 2)

The RS concurs with the IPA's recommendation at page 103, footnote 185 of the IPA Plan, concerning the use of the Annual Contract Value ("ACV") method to allocate the utility's HACP funds among the LTPPAs for the purchase of curtailed RECs. The RS says it is noting its concurrence with the IPA's recommendation because it is the RS who, in the Docket No. 13-0546 Rehearing proceeding, requested that the use of the ACV method be revisited in the 2015-2016 IPA Plan proceeding. (RS Objections at 4)

The RS again notes the IPA has recommended that "the hourly ACP funds available for that procurement [of DG RECs] be reduced by the amount needed to ensure full payment of any 2014-2015 curtailed RECs." In this connection, the RS wishes to raise for resolution in this docket an administrative issue that has arisen concerning "ensur[ing] full payment of any 2014-2015 curtailed RECs." The RS says NextEra Energy Resources, LLC ("NextEra") and its project subsidiary FPL Energy Illinois Wind, LLC ("FPL Illinois") have encountered this issue due to the intersection of certain terms of the LTPPA with the procurement of curtailed RECs by ComEd using HACP funds. The RS suggests this issue may prevent FPL Illinois from being able to sell its full amount of curtailed RECs for 2014-2015 to ComEd, even if ComEd has sufficient HACP funds to make the purchases. The RS states that resolution of the issue does not require a change to the LTPPA; it can be addressed through the form of contract for curtailed REC purchases with HACP funds. (RS Objections at 4-5)

The RS indicates the ComEd LTPPAs provide that if, at the end of a delivery year, the LTPPA Supplier has delivered less than 100% but more than 90% of its Annual Contract Quantity ("ACQ"), its deliveries at the start of the next year are used to make up the shortfall. The RS says it is only after the LTPPA Supplier's deliveries reach 100% of ACQ for the previous year that its deliveries begin to count toward the current year's ACQ. Additionally, the RS states that if there is a curtailment, the

percentage of the output of its facility that the LTPPA Supplier can deliver in each hour (referred to in the LTPPA as the "Applicable Percentage") is reduced by the curtailment percentage. If the LTPPA Supplier starts the new delivery year still delivering RECs to make up an ACQ shortfall from the previous year, the RS says the curtailment percentage and the Applicable Percentage from the preceding year are used until the ACQ shortfall is made up, at which point the current year's curtailment percentage and Applicable Percentage go into effect for the remaining REC deliveries from the facility in that year. (RS Objections at 5)

The RS says FPL Illinois began the 2014-2015 delivery year in a shortfall situation from the preceding (2013-2014) delivery year. Further, the RS says because the 2013-2014 curtailment percentage was 18.6%, FPL Illinois' Applicable Percentage, and thus the amount of RECs it could deliver in any hour, continued to be significantly reduced going into the new (2014-2015) delivery year. The RS states it was not until July 2014 that FPL Illinois had delivered sufficient RECs to ComEd to make up the 2013-2014 shortfall and reach 100% of the adjusted (for the curtailment) 2013-2014 ACQ. The RS says the application of the 18.6% curtailment percentage for 2013-2014 to deliveries after May 31, 2014 increased the difficulty of, and increased the time needed to deliver RECs to, make up the 2013-2014 ACQ shortfall. (RS Objections at 5-6)

The RS states that due to the foregoing circumstances, and taking into account the maximum potential hourly output of FPL Illinois' wind farm, FPL Illinois may be unable to deliver the full 2014-2015 ACQ (as adjusted by the 2014-2015 curtailment percentage) by May 31, 2015. Should this occur, then, as required by the LTPPA, the RS says FPL Illinois will be continuing to deliver short-fall 2014-2015 RECs to ComEd for some period of time after May 31, 2015. RS says FPL Illinois, under the contract, will not be allowed to deliver to ComEd, and be paid for, curtailed RECs with a vintage later than May 2015. In other words, the RS states that although FPL Illinois will be obligated to deliver to ComEd non-curtailed RECs with vintages of June 2015, July 2015, and possibly later months to make up the shortfall of 2014-2015 non-curtailed RECs, FPL Illinois will not be allowed to deliver and be paid for the associated curtailed RECs with June 2015, July 2015 or later vintages. (RS Objections at 6)

According to the RS, to address this situation, NextEra believes that ComEd should be required to accept and pay for curtailed RECs of the same month's vintages as the associated non-curtailed RECs. So long as the LTPPA Supplier is delivering the non-curtailed RECs and energy attributable to the prior year to make up a short-fall situation, the RS claims the LTPPA Supplier should also be allowed to deliver the prior year curtailed RECs associated with the prior year non-curtailed RECs and energy. The RS maintains this would not require a modification to the LTPPA, but only a change to the form of contract that ComEd developed for the purchase of curtailed RECs using HACP funds. In the RS' view, this approach would "match" curtailed RECs with the associated non-curtailed RECs generated by the supplier in each period. The RS asserts it would be consistent with the settlement mechanism for the utility's purchases of curtailed RECs that the RS presented in the Docket No. 13-0546 Rehearing, under

which the utility would settle with the LTPPA supplier each month for the curtailed RECs on the basis of the same price data used to settle the non-curtailed part of the LTPPAs, i.e., the Contract Price less the Day-Ahead LMPs in that month. The RS contends this approach would ensure that a LTPPA Supplier in a shortfall situation for the prior year will receive payment for its full complement of curtailed RECs for the current year (to the extent permitted by its allocated share of the utility's HACP funds). (RS Objections at 6-7)

The IPA states that it takes no position concerning the RS' objection related to the delivery of curtailed RECs when a prior-year shortfall exists. The IPA states that, "This appears to be a contract issue between the Renewables Suppliers and ComEd related to the curtailment for the 2014-2015 delivery year, and not germane to the 2015 Procurement Plan." The RS states that although the issue has arisen and been identified in the implementation of the purchase of LTPPA RECs for 2014-2015, it is pertinent to 2015-2016 and to any future year in which a curtailment of the LTPPAs could be required. The RS believes the Commission's order should issue appropriate directives, as requested by the RS, to prevent the issue from recurring in 2015-2016 and any other future year in which there is an LTPPA curtailment. The RS believes consideration and resolution of the issue in this proceeding is the most expeditious and efficient way to address and resolve the issue. The RS maintains the Commission should provide direction in its order in this proceeding to resolve this issue for the future, in order to carry out the intent of the Docket No. 13-0546 Rehearing Order. (RS Reply at 2-3)

ComEd agrees with the RS that the amount of HACP funds available to purchase DG RECs should be reduced by the amount of accumulated HACP funds needed to purchase curtailed LTPPA RECs in 2015-2016, should a curtailment of the LTPPAs in 2015-2016 be determined to be necessary. The RS says ComEd's Response raises a new issue concerning the dates to be used for determining the accumulated HACP balances available for the various purposes designated by the Commission. Specifically, ComEd contends that (1) the HACP funds available to purchase curtailed LTPPA RECs for the 2014-2015 delivery year is the accumulated HACP balance at May 31, 2013; and (2) the HACP funds available to purchase DG RECs in 2015-2016 (and, if necessary, to purchase curtailed 2015-2016 LTPPA RECs) is the accumulated HACP balance at May 31, 2014. The RS disagree with these dates. According to the RS, in the Docket No. 13-0546 Rehearing Order, the Commission directed that ComEd's balance of accumulated HACP funds at May 31, 2014 should be used to purchase curtailed LTPPA RECs in 2014-2015. The RS asserts, the accumulated balance of HACP funds to be used to purchase DG RECs in 2015-2016 (and, if necessary, to purchase curtailed 2015-2016 LTPPA RECs) is the accumulated HACP balance at May 31, 2015. (RS Reply at 3)

ComEd asserts that the RS' proposed revision to the IPA Plan "misunderstands the law," but the RS complains ComEd does not explain what law is misunderstood. The RS assume that ComEd is referring to Section 1-75(c)(5) of the IPA Act. (RS Reply at 3)

According to the RS, this provision imposes a requirement that in a given plan year, the electric utility's accumulated balance of HACP funds as of the prior year ending May 31 must be spent on the procurement of renewable resources by the utility. The RS contends the provision is not a limitation on the ability of the Commission to direct, in a particular order, that HACP funds collected after May 31 of the prior year be used for a particular purpose. The RS states that in the Docket No. 13-0546 Rehearing Order, the Commission directed that the accumulated balance of ComEd's HACP funds at May 31, 2014 be used to purchase curtailed LTPPA RECs in 2014-2015. (RS Reply at 3-4)

The RS says ComEd cites the Commission's original (December 18, 2013) order in Docket No. 13-0546 in support of its position, but ignores the Docket No. 13-0546 Rehearing Order. The RS says the Commission observed, correctly, that "no party objected to the RS's proposed implementation methodology in its briefs" and that "the IPA has no objection to the Commission adopting this methodology." (RS Reply at 4-5, citing Docket No. 13-0546, Order on Rehearing at 55)

The RS states that ComEd never objected to, or proposed a change to, the RS' proposal that the utilities' accumulated balance of HACP funds at the start of the year (June 1) would be used to purchase any curtailed LTPPA RECS during that year. The RS insists that in the Docket No. 13-0546 Rehearing Order, the Commission approved the RS' proposal that the utility's accumulated balance of HACP funds at the start of a plan year (i.e., June 1, 2014) would be used to purchase any curtailed LTPPA RECs during that year (2014-2015). The RS claims it necessarily follows that the balance of HACP funds to be used to fund a DG REC procurement in 2015-2016 (and, if necessary, the purchase of any curtailed LTPPA RECs for 2015-2016) should be the accumulated balance at May 31/June 1, 2015. (RS Reply at 5-6)

The RS says the IPA agrees with the RS' recommendation that the HACP funds to be used to fund the DG REC procurement in 2015-2016 should be the utilities' accumulated balances of HACP funds as of May 31, 2015. The RS maintains that the revisions that ComEd proposes to the text at page 3 of the IPA Plan (ComEd Response at 14-15) are unnecessary and inappropriate. The RS believes the modified item 10 in the IPA's Action Plan (IPA Plan at 6) that the RS proposed at page 4 of its Objections should be adopted. (RS Reply at 6-7)

ComEd urges the Commission to reject the RS' concerns arising from the inability to produce the full amount of curtailed 2014-2015 RECs by May 31, 2015 for delivery to ComEd where the supplier began the 2014-2015 delivery year in a shortfall make-up position from 2013-2014. ComEd makes three points: (1) The RS negotiated and signed contracts with ComEd that state that the curtailed RECs that will be purchased are those that are curtailed between June 1, 2014 and May 31, 2015, and the Commission cannot revise the contracts without violating constitutional principles; (2) the contracts were reviewed and approved by the IPA and Commission Staff; and (3) if FPL Energy, the RS that entered 2014-2015 in a shortfall makeup situation from

2013-2014) "operates at or above the level to which it committed in its original LTPPA contract, it will generate enough curtailed RECs to receive its full allotment of hourly ACP funds." According to the RS, ComEd does not refute any of the underlying facts set forth at pages 5-6 of the RS' Objections. (RS Reply at 7)

As to ComEd's first point, to be clear, the RS understands that contracts for the purchase of curtailed RECs attributable to 2014-2015 have been signed, but the RS is requesting that the Commission resolve the issue that has been identified for future years. The RS says this would not require any interference with the one-year contract for 2014-2015. The RS asserts the contracts that were signed were not "negotiated;" they were dictated by ComEd. The RS says FPL Energy requested modifications to the contract that was tendered by ComEd, but FPL Energy's objections were to no avail. The RS says FPL Energy was told that if it did not sign the contract with the terms as dictated by ComEd, ComEd would not purchase any curtailed 2014-2015 RECs from FPL Energy. In order to obtain the cash flow from the sale of curtailed RECs and receive the benefits of the Commission's decision in the Docket No. 13-0546 Rehearing Order, the RS asserts FPL Energy was left with no choice but to sign the contract dictated by ComEd with the objectionable provisions. The RS says FPL Energy's only other option would have been to refuse to sign ComEd's contract and file a complaint against ComEd with the Commission, which likely could have taken an extended period to resolve. (RS Reply at 7-8)

The RS believes the contract for purchase of 2014-2015 curtailed RECs should not serve as a template for future years' contracts. The RS argues that the Commission should order that the problem the RS has identified be corrected for future years. The RS says the sole purpose of the contract is to effectuate the Commission's Rehearing Order in Docket No. 13-0546. If the Commission finds that the contract dictated by ComEd does not fully and properly implement the Commission's decision in the Rehearing Order, or improperly infringes on a RS' ability to sell its full amount of curtailed RECs to ComEd and be compensated for them at the pricing approved in the Rehearing Order, which the RS claims is the case, then the RS believes the Commission can and should direct ComEd to make changes in the terms under which it purchases the curtailed RECs. (RS Reply at 8)

In the RS' view, ComEd provides no explanation or justification for why, in the circumstances described in the RS' Objections, the curtailed RECs that ComEd will purchase must be limited to vintage June 1 through May 31 RECs. The RS argues that if an LTPPA Supplier is still producing and delivering non-curtailed RECs and energy for a procurement plan year to ComEd after May 31 of that year, to make up a shortfall for that procurement plan year – as required by the LTPPA – the supplier should also be able to produce and deliver the curtailed RECs during the same time period that the associated non-curtailed RECs and energy are being produced and delivered to ComEd. (RS Reply at 8)

The RS claims the problem being encountered by FPL Energy for 2014-2015 could be encountered, in any future delivery year in which there is a LTPPA curtailment,

by a LTPPA supplier that enters the year in a shortfall make-up situation from the previous year. The RS says FPL Energy will encounter this situation for 2015-2016 in the event of the expected shortfall. (RS Reply at 8-9)

With respect to ComEd's second point, the RS says whatever process ComEd followed to obtain the approval of its contract form by the IPA and Staff, that process did not include an opportunity for the LTPPA suppliers to express their concerns to the IPA and Staff about ComEd's contract form. The RS claims when ComEd first tendered the contract form to FPL Energy, ComEd stated that the contract form had already been approved by the IPA and Staff – before the counter-parties had an opportunity to review and comment on the contract. The RS says this has been a source of ongoing difficulty for the RS, in several plan years, with respect to ComEd's post-order implementation of rulings and directives in the Commission's procurement plan orders. The RS believes the Commission should direct that, in the future, the process of developing and entering into contracts with ComEd to implement rulings and directives in the Commission's procurement plan orders should include an opportunity for affected parties – particularly counter-parties to the proposed contract forms – to participate in order to make known to the IPA and Staff any concerns about ComEd's proposed implementation of the Commission's rulings and directives. (RS Reply at 9)

With respect to ComEd's third point, the RS asserts that under the LTPPAs, the maximum amount of energy and RECs that a supplier can deliver in any hour is limited to the product of (i) the maximum plant capacity times (ii) an "Applicable Percentage." In the event of a curtailment, the RS says the "Applicable Percentage" is further reduced by the curtailment percentage. Based on these LTPPA terms, the RS says the wind facility cannot in fact operate and deliver to ComEd RECs "above the level to which it committed in its original LTPPA contract." The RS adds that if the facility operates "at . . . the level to which it committed in its original LTPPA contract" from June 1, 2014 to May 31, 2015 and delivers all the RECs produced in that period to ComEd as 2014-2015 RECs, it will be able to deliver to ComEd the full amount of non-curtailed and curtailed RECs for the delivery year. The RS asserts because FPL Energy spent June and most of July of the 2014-2015 procurement plan year producing RECs attributed to 2013-2014 – as required by the LTPPA – FPL Energy would not be able to "catch up" over the remaining 10 months such that it produces the full contractual amounts of non-curtailed and curtailed delivery year 2014-2015 RECs by May 31, 2015. (RS Reply at 9-10)

The RS complains that ComEd fails to explain why the curtailed 2014-2015 RECs it will accept and pay for should be limited to RECs with a vintage no later than May 2015, nor why this limitation should apply for any future year in which there is an LTPPA curtailment. The RS further complains ComEd does not explain why, if a new plan year starts but a LTPPA supplier is still producing and delivering non-curtailed RECs and energy to ComEd to make up a shortfall for the previous plan year, as required by the LTPPA, the supplier should not be able to also produce and deliver to ComEd, and be paid for, the associated curtailed RECs. (RS Reply at 10)

The RS states that under the LTPPAs, the amount of energy and RECs produced and delivered, and the settlement price, are determined on an hourly basis. The RS says in a curtailment situation, the RECs produced and delivered in each hour can be divided into the non-curtailed RECs and the curtailed RECs, based on the curtailment percentage. The RS says under its secondary proposal in Docket No. 13-0546 (which the Commission adopted), the curtailed RECs for each month should be settled with the utility using the same price data that is used to settle the non-curtailed RECs for the month. The RS believes if, after May 31 of a procurement plan year, a LTPPA supplier is still producing and delivering non-curtailed RECs to ComEd for that year due to making up a shortfall situation, the supplier should also be able to deliver to ComEd, and be paid for, the curtailed RECs associated with those non-curtailed RECs. The RS claims ComEd has failed to explain why this should not be the case. (RS Reply at 10-11)

Staff states that if the solar REC procurement is conducted for 5-year contracts (rather than one-year contracts as proposed in the IPA Plan),

> [I]t would be prudent for the new 5-year contracts to include provisions for curtailment, should Section 1-75(c) budgetary limitations make curtailments necessary, again. Furthermore, Staff opines that it would be fairer to make the new 5-year contracts subordinate to the existing long-term contracts. That is, it would be fairer to curtail the new 5-year contracts prior to curtailing the existing long-term contracts.

The RS takes no position on whether (1) the IPA Plan for 2015 should include a solar REC procurement, or (2) if a solar REC procurement is included in the IPA Plan, the procurement should be for one-year contracts or 5-year contracts. However, the RS agrees with Staff that if a procurement for multi-year solar REC contracts is included in the IPA Plan, the solar REC contracts should provide that in the event of the need for a curtailment due to the rate cap limits of Section 1-75(c)(2) of the IPA Act, the solar REC contracts will be curtailed prior to any curtailment of the existing LTPPAs. The RS says the contracts would provide that the solar REC contracts would be curtailed, up to 100% if necessary, to eliminate the exceedance of the Renewable Resources Budget, before the LTPPAs are curtailed. (RS Reply at 11)

The RS does not object to ComEd's revision to the process proposed by the Proposed Order for giving suppliers input into the development of contracts in the future, if the Commission concludes that ComEd's approach is better. The RS believes either the approach set forth in the Proposed Order or the approach proposed by ComEd will provide suppliers with input into the development of the contract forms and terms – rather than having the contracts presented to them as a unilateral decree by ComEd, accompanied by the assertion that the contracts have already been pre-approved by the IPA and the Staff. (RS RBOE at 2)

The RS believes in either process, the existing contract forms should not be given any necessary presumption of correctness or precedential weight. The RS says

the existing contracts have not been developed with input from the LTPPA Suppliers. The RS asserts they should not continue to be used, without revision, simply because they are the "existing contracts." The RS says in the future, in each succeeding year, the contract terms and the experience implementing the contracts should be reviewed by the contract parties, the IPA and Staff, and revisions should be considered for adoption based on the experience of prior periods. (RS RBOE at 2-3)

5. ELPC's Position

In ELPC's view, the best long-term way to meet the statutory goals is for the IPA to structure a simple, transparent and long-term renewable energy procurement program to help support the development of a mature and competitive renewable energy industry in the state. ELPC notes the IPA has proposed to use funds remaining in the utilities' RRB to procure one-year SRECs from new or existing projects. ELPC argues that procuring one-year SRECs is an imprudent use of funds and does not meet the IPA's requirement to "support the development of…renewable resources." ELPC says it understands the forecasting and budgeting challenge faced by the IPA in developing a long-term renewable resource procurement strategy in light of the shifting load forecasts due to customer switching to, and from, competitive suppliers. However, to the extent possible, ELPC recommends a risk hedging strategy that does not rely primarily on procuring one-year SRECs. ELPC claims there is ample evidence from Illinois and elsewhere that new PV resources cannot be developed using one-year SREC contracts. ELPC believes the IPA's plan to allocate the entire RRB to one-year SREC contracts will likely not result in new solar PV development in Illinois and will not further the goals of the Illinois RPS. (ELPC Objections at 1-2)

In order to address the risks of contract curtailments due to fluctuations in the utilities' load forecasts, ELPC recommends that the IPA explore alternative risk-hedging strategies that could lead to new renewable energy development. ELPC suggests the IPA should explore the possibility of using 5-year DG SREC contracts paid through an up-front rebate with appropriate claw-back provisions for non-performance. ELPC further suggests the IPA should also explore other methods for creating more budget stability, including the possibility of having ComEd and Ameren escrow the portion of this year's RRB necessary to cover future contractual payments, instead of relying on future year budgets. ELPC says it understands this could lead to the procurement of fewer DG SRECs using the 2015-2016 funds, but claims the SRECs actually procured would be linked to the development of new projects, which would further the state's renewable energy goals and lead to longer-term price stability. To the extent possible, ELPC suggests the IPA should strive to administer programs that will lead to the development of new renewable energy systems in Illinois, rather than just provide an additional income stream to projects that have already been built and financed. In ELPC's view, doing so would yield a variety of benefits consistent with the goals of the IPA Act, including encouraging resource diversity, advancing price competition and price stability, promoting investment and development, and avoiding the need for new generation, transmission, and distribution infrastructure. ELPC claims that failing to do so will preclude the growth of private investment in this sector, deprive the electric

system of significant and measurable benefits, and inhibit the development of a diverse, mature and sustainable renewable energy industry in Illinois. (ELPC Objections at 2-3)

ELPC reports that the IPA has proposed using Alternative Compliance Payments from hourly customers to purchase DG resources. ELPC believes the IPA must strive to procure, to the extent possible, at least half of the DG RECs from systems under 25 kW in size and half from systems above 25 kW in size. ELPC claims contracts for these RECs must be at least 5 years in length and RECs can come from anywhere on the Illinois distribution system. While ELPC agrees with the use of hourly funds for the procurement of DG resources, ELPC objects to the complicated nature of the process and the lack of recognition of the differences between large and small systems. (ELPC Objections at 3)

The IPA proposes to set benchmarks and judge project bids in two separate categories: systems under 25 kW and systems over 25 kW. While ELPC agrees that the IPA has the statutory requirement to specifically consider the under 25 kW systems separately, ELPC says nothing precludes the IPA from also creating separate categories within the above 25 kW group. ELPC claims there are marked differences in both the costs and the benefits between a 40 kW system and a 2 MW system, for example, and under the current proposal they would be forced to compete head-to-head. ELPC contends this would likely result in very large 1-2 MW systems dominating the above 25 kW bid group and very few mid-size commercial systems in the market. ELPC contends it knows of real world situations where customers are planning to reduce the capacity of planned systems to 25 kW or below because they fear they won't be able to compete in the 25 kW to 2 MW category. ELPC believes this would not be an economically efficient or desirable outcome of the IPA's procurement process. ELPC says the IPA Act emphasizes the importance of a "diverse electricity supply portfolio" in helping to meet the IPA's goals. ELPC suggests the IPA should include a sub-category for systems 25 kW to 200 kW in order to promote a more diverse and mature renewable energy marketplace in Illinois. (ELPC Objections at 4)

ELPC states that the IPA has set a minimum bid requirement of 1 MW in capacity, apparently to satisfy the statutory language directing the IPA to "solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." According to ELPC, this statutory provision requiring "aggregation" into 1 MW blocks was originally written in the law to relieve administrative burdens on the contracting utilities, but as applied by the IPA in its Plan it will create the unintended consequence of excluding participants from the market, which will ultimately limit cost effective bids. The IPA says the IPA's proposed minimum bid requirement will limit bids from projects from local developers that don't have 1 MW of capacity under their purview, which will tend to limit competition and increase overall costs. In ELPC's view, the IPA and the Commission should not interpret this legislation rigidly to require formal "aggregation" before bids are submitted to the IPA. ELPC suggests the IPA could interpret this language to simply award contracts in no less than one MW blocks. ELPC says this would serve the purposes of relieving the burden on contracting parties, but would not impose unnecessary burdens

on bidders in advance of the procurement. ELPC says it is a basic rule of statutory construction that agencies should seek to interpret ambiguous statutory directives to further the apparent intent of the legislature. ELPC states that in this case, there is no apparent statutory intent to require aggregation in advance of the procurement in a manner that would frustrate customer acquisition, limit the pool of market participants, and increase overall costs for the procurement. ELPC suggests the IPA should interpret the law and develop its plan to further the legislative goals of procuring "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest cost over time." ELPC asserts eliminating the requirement of minimum bids and replacing it with a process to award contracts in blocks of 1 MW capacity would promote the legislative goal of administrative efficiency but will also promote the IPA's goal of procuring resources at the "lowest cost over time" by expanding the pool of eligible bids. (ELPC Objections at 5)

The IPA requires a $10/REC credit deposit for bidders. ELPC argues that coupled with the IPA's proposed 1 MW minimum bid requirement, this ultimately means that project developers will be required to come up with a deposit of approximately $50,000 per bid. ELPC says it has heard from stakeholders that a $50,000 bid deposit may be prohibitive for smaller participants in the market and may have the unintended consequence of limiting bids from local developers. ELPC contends that limiting bids from these participants could have the unintended consequence of again limiting supply, reducing competition, and potentially increasing prices. ELPC suggests further discussion and comment regarding the appropriate bid deposit requirement in order to appropriately limit speculative bidding while also promoting maximum participation from the market. (ELPC Objections at 5-6)

According to ELPC, the IPA suggested that it will not allow speculative bidding when procuring DG RECs, meaning that projects will have to be identified in the bid. ELPC complains that the Plan includes several examples of the types of evidence bidders may be able to use to show projects aren't speculative, but it does not definitely identify the level of evidence that will be required. In ELPC's view, the IPA should either definitively say which of these pieces of documentation will be accepted as proof, or delineate the process for determining the appropriate documentation. (ELPC Objections at 6)

The IPA suggested that DG projects need only start providing RECs sometime during the 2015-2016 procurement year. If systems do not start providing RECs during that timeframe, the IPA suggests that the "bidder's contract volume will be reduced accordingly by the amount allocated to that system or the contract will be cancelled." ELPC believes the IPA intended that contracts would be "cancelled" only if there is one project in the bid and it fails to deliver. In all other situations, ELPC believes it would be appropriate that the contract amount would only be reduced, but not cancelled. ELPC complains that the plan does not clearly indicate this intent and seems to suggest that the choice of reducing or canceling a contract is at the discretion of the IPA and suggests this should be clarified. (ELPC Objections at 6-7)

The IPA suggests that winning projects need only start to supply RECs sometime during the 2015-2016 procurement year to qualify, and that contracts will be 5 years in length. Bidders will be asked to provide in their bids the annual and 5 year total REC amounts for each project. It is unclear to ELPC whether the 5 years is measured from the beginning of the 2015 procurement year or when the system starts to produce RECs. ELPC says it is clear that systems will only be paid for their RECs when they become operational and are registered with PJM-GATS or MRETS. ELPC says it is unclear whether the contract term will last beyond the 2019 procurement year if systems begin delivery of RECs late in the 2015 procurement year. ELPC believes the Plan should clarify this issue one way or the other. If payment will not be made past the 2019 procurement year, ELPC says the IPA should clarify that non-operational systems at the time of bid will have lower first year (PY 2015-2016) REC bids than in other years. (ELPC Objections at 7)

According to ELPC, ComEd and Ameren apparently read the "sub-targets" as optional or aspirational goals, rather than requirements, arguing that "there is not a clear requirement that REC sub-targets must be met in a year where the total REC target has been exceeded." Both utilities go on to object to the IPA's proposal to include a solar REC procurement using Renewable Resource Budget monies in 2015. (ELPC Response at 5)

ELPC disagrees with this interpretation of the statute. ELPC states that the RPS targets at Section 1-75(c) of the IPA Act are a floor, not a ceiling, since the legislature used the phrase "at least." ELPC argues that the subtargets are not optional, but they are mandatory targets since the Legislature used the word "shall" in each of the subtarget sections. ELPC says it is true that the IPA need only comply with the subtargets "to the extent that it is available," but the "availability" of these subtargets is determined by whether or not there are still available funds under the statutory rate cap at Section 1-75(c)(2)(E) not whether the "total REC target has been exceeded" as Ameren suggests. (ELPC Response at 5)

ELPC says the statutory rate cap creates the RRB that the IPA has always used to determine whether or not resources are "available" for the purposes of the IPA Act. ELPC states that in last year's Plan, the IPA explained that the utilities have additional wind, solar and distributed generation resources that could be procured, but that "the rate cap prevents procurement of these or any other resources on behalf of eligible retail customers as long as the cap is exceeded." ELPC indicates this year's plan does not exceed the rate cap, but the utilities have not met their mandated minimums for solar or distributed generation. ELPC believes the statute requires the IPA to procure additional solar and distributed generation RECs until the utilities' mandated carve-outs are met or until the rate cap at Section 1-75(c)(2)(E) of the IPA Act is exceeded. (ELPC Response at 5-6)

Ameren also opposes the IPA's plan to procure one-year SRECs using the RRB, arguing that logic suggests that a one-year SREC procurement would not provide an incentive for new construction of solar facilities within Illinois. Ameren suggests the

more likely outcome would be a procurement that results in contracts from existing solar facilities. ELPC believes that the IPA should proceed with a solar procurement this year, but shares Ameren's concerns about the prudence and effectiveness of a one-year REC procurement for existing solar resources. ELPC agrees with Ameren that a one-year REC procurement is unlikely to result in the development of new renewable energy projects in Illinois. ELPC believes the IPA should prioritize use of its limited resources in a way that leads to the development of new renewable energy facilities, rather than simply directing payments to facilities that have already been fully financed and constructed. ELPC claims this would further the statutory goals and purposes of the RPS and help ensure the lower and more stable renewable energy procurement costs over time, as required by the statute. (ELPC Response at 6)

Ameren argues that the distributed generation market is not mature enough for the program as designed by the IPA, and since Ameren would be the counterparty to contracts signed under this process it cannot support the proposal. To alleviate these concerns, Ameren suggests that the IPA be the counterparty to any DG contracts, and that the Commission direct Ameren to transfer any hourly ACP money, either in one lump sum or yearly, to the IPA to cover those costs. In addition, Ameren wants the 2015 plan to explicitly state that contracts won't exceed the amount of money already collected from hourly customers for RPS compliance. Finally Ameren wants the Commission to order that the 2015 procurement of DG resources be contingent on the success of the first supplemental solar procurement. ELPC disagrees with this assessment of the market and the changes to the process. (ELPC Response at 6-7)

On the issue of whether the utility should be the counterparty on behalf of hourly customers to any contracts made between REC providers, ELPC says the statute is clear that "the Agency shall increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year…" According to ELPC the intent is for the utility to be the contracting entity with the renewable resources provider. ELPC believes the Commission should reject Ameren's suggestion. (ELPC Response at 7)

ELPC also disagrees with Ameren's contention that the distributed generation market is not mature enough to fully take advantage of available hourly ACP funds in the manner detailed in the plan. ELPC says Ameren wants the Commission to order that the 2015 procurement of DG resources be contingent on the success of the first supplemental solar procurement. ELPC also says that in June 2014 the IPA held a workshop on distributed generation in which at least 40 entities participated, including REC aggregators, local solar companies, and national solar companies. ELPC adds that many of these entities have been anticipating a solar DG procurement ever since the DG carve-out was first enacted in 2011 and have participated in numerous DG procurements in other states. (ELPC Response at 7)

ELPC contends markets can scale quickly and effectively. ELPC says the IPA suggests through its 2015 procurement and the supplemental solar procurement it will spend a maximum of approximately $43 million dollars on DG resources. At market

rates, ELPC suggests this could procure between 30 and 60 MW of distributed generation. ELPC claims interconnection statistics from the utilities suggest there is somewhere between 10 and 15 MW of qualifying distributed generation already operational. ELPC says according to the Solar Energy Industries Association's 2014 Second quarter Industry Report 42,000 distributed generation installations happened in the second quarter of 2014 alone, including 247 MW of residential and 261 MW of non-residential distributed systems. ELPC also says Missouri installed 29 MW of solar in the second quarter of 2014 and New Jersey installed 53 MW. ELPC states that the IPA's proposed procurements would happen over four quarters with additional time allowed to energize new systems. ELPC believes the market will respond appropriately to these offerings under this timeline, as levels of DG similar to the IPA's 2015 total have been installed in a single quarter in other states. (ELPC Response at 8)

The IPA proposes to procure different products with the 2015 procurement and the supplemental procurement. The IPA will offer to procure only solar resources in the supplemental procurement, whereas it will offer to procure any eligible distributed generation resources in the 2015 procurement, including wind, solar, biomass, etc. Finally, the IPA has proposed to procure only new distributed generation resources in the supplemental procurement, whereas the in the 2015 procurement it proposes to procure only identified projects. These are different offerings and ELPC believes it would be imprudent for the Commission to allow one to be contingent on the success of another. (ELPC Response at 8)

ComEd argues that for contracting purposes the statute requires the IPA to aggregate distributed renewable energy into groups of no less than 1 MW for the purposes of contracting with the utility. In ELPC's view, the language in the statute is ambiguous as to whether the contract must be for 1 MW or whether the IPA must merely aggregate the bids into groups of 1 MW. ELPC maintains that the IPA should apply the aggregation requirement to the contracts ultimately signed by the utilities, but should not require bidders to aggregate their bids into 1 MW blocks before they can bid into the process. By applying the aggregation requirement to the "back-end" of the process instead of the "front-end," ELPC claims the IPA will enable a larger pool of bidders and likely lower prices while still meeting the legislature's objective to "minimize the administrative burden on contracting entities." (ELPC Response at 9)

ComEd argues that the IPA is not bound to purchase RECs from distributed generation resources that are less than 25 kW in capacity. Rather, ComEd argues that the IPA is first and foremost bound to procure "cost-effective" resources and therefore all systems should be judged equally. ELPC disagrees with this interpretation of the statute. ELPC argues that the IPA Act uses the phrase "shall," which implies that the under-25 kW sub-target requirement is mandatory to the extent that these resources are available in the market within the renewable energy resources budget rate caps. (ELPC Response at 9)

According to ELPC, ComEd's interpretation that the IPA should ignore the specific statutory subtargets unless those resources can be purchased at the same

price as the cheapest available DG RECs conflicts with several canons of statutory construction, including the principle that specific statutory language controls over the general and the principle that the Commission should strive to avoid interpretations that render parts of the statute to be superfluous or "mere surplusage." ELPC suggests that due to economies of scale, it is unlikely that the under-25 kW category of DG projects will ever be available at the same price as DG RECs from larger systems. ELPC asserts that the legislature adopted this special small system carve-out to ensure that there was appropriate diversity in the DG market. If it intended the IPA to only procure small system RECs if there was money left over in its budget after meeting the overall DG target, ELPC claims it would have said so. (ELPC Response at 10)

ELPC claims the Commission has previously rejected a similar argument raised by ComEd. ELPC says the 2012 Procurement Year was the last year in which there was a renewable procurement, and the Commission approved a plan that allowed the IPA to "sort bids according to price and source" and "select the lowest bid combination that yields at least the minimum carve out requirements…" ELPC contends the same principle applies to the procurement of distributed generation resources as other resources and the Commission should continue to allow the IPA to create separate benchmarks for different resources, and allow the IPA to procure the bid combinations that meet the minimum carve out requirements (ELPC Response at 10)

According to ELPC, ComEd misquotes and misinterprets the Commission's order in Docket No. 12-0544. ELPC agrees with the IPA that the 2013 plan was developed under an entirely different set of factual circumstances that do not apply here. ELPC also claims the cited language by ComEd's was not the Commission's "ultimate conclusion," as ComEd stated, but instead it was the "IPA's view" at the time, which was motivated by the IPA's observation that the "costs of conducting a procurement event for a relatively small number of RECs" may not be justified in light of the "exceptionally low" volume of SRECs needed at that time. ELPC insists the circumstances are different today. ELPC notes the IPA is confident in October 2014 that the renewable resources budget will be sufficient to support a 2015-2016 one-year SREC procurement. ELPC maintains that the IPA Act creates a clear statutory obligation for the IPA to procure renewable resources from solar and distributed generation resources if they are "available" under the statutory rate caps. ELPC urges the Commission to defer to IPA's policy judgment regarding the prudency of procuring solar and distributed generation resources as part of its overall Plan. (ELPC Reply at 1-2)

Staff disagrees with ELPC's position on one-year SREC procurements, but ELPC says Staff misunderstands ELPC's position. ELPC says it did not argue that SRECs must be purchased exclusively from Illinois facilities; that SRECs must be purchased exclusively from new facilities; or that the IPA must "single-handedly bestow all that is necessary to incentivize investment in solar photovoltaic generating resources." ELPC says it is arguing that the IPA's should structure its procurement plan to meet its statutory requirement to "support the development of…renewable resources." ELPC maintains procuring one-year SRECs will not support the development of renewable resources. ELPC claims at most, it will provide some extra income to project

developers that have already financed and constructed photovoltaic systems using other incentives. ELPC contends Staff is not correct that "a REC from a series of 10-year-old solar panels is just as valid as a REC from a series of 1-year-old solar panels." (ELPC Reply at 3)

ELPC says the Legislature intended the IPA's procurement plans to support development of renewable resources. ELPC agrees with the IPA that the development of new renewable resources is also "important to maintaining the lowest total cost over time, taking into account the benefits of price stability. ELPC maintains the IPA's plan to procure one-year SRECs will likely not further these statutory goals. While ELPC is sympathetic to the IPA's concerns about the budgeting risks introduced by load migration and longer-term contracts, ELPC believes there are likely ways that the IPA can mitigate these risks in ways that will still lead to the development of renewable resources, as required by law. ELPC asserts these alternatives merit further consideration. (ELPC Reply at 3-4)

The IPA has proposed to set a minimum bid requirement of 1 MW for RECs from DG projects. ELPC initially objected to the IPA's method of requiring bids in no less than 1 MW blocks. ComEd also objected to the IPA's method of block bids, suggesting that bids of 1 MW in size should be selected at a single price per REC for each block bid, rather than the IPA's proposed approach of selecting individual systems within bids at potentially different price points.

Upon review of the parties' Responses, ELPC withdraws its objection and supports the IPA's proposed method of selecting projects from aggregated 1 MW bids. ELPC agrees that the IPA must balance competing statutory objectives in the development of its procurement process. ELPC says the 1 MW bidding requirement presents some challenges for smaller developers, but ComEd's alternative interpretation would be "extremely challenging" for small developers. ELPC states that at as the law calls for 50% of RECs to come from systems below 25 kW in size, the IPA is correct that "developing a procurement model that creates barriers for small system participation would be contrary to the preference articulated in the law." ELPC believes the IPA must be given some discretion to design a procurement program that best meets these competing objectives, particularly in complex procurement and bidding terms that involve the IPA's expertise. (ELPC Reply at 4)

ELPC recommended that the IPA create a middle tier of projects between 25 kW and 200 kW in order to promote a more diverse and mature renewable energy marketplace in Illinois. The IPA and Staff disagreed with this recommendation. The IPA did not question the value of promoting a mid-sized tier of projects, but determined that this particular Plan may not be the place to do it in light of the small budget associated with this procurement. Staff argued that ELPC presented "no coherent rationale" for pursuing SRECs from mid-sized systems. (ELPC Reply at 5)

ELPC believes that the rationale for promoting a balanced renewable energy market of small, mid-sized and larger distributed generation systems is coherent and

important. ELPC also understands that the IPA must develop its plan to best meet a number of competing policy objectives. Under the specific circumstances of this case, ELPC withdraws its objection regarding the development of a middle tier of projects. ELPC believes the Commission should not accept Staff's argument that there would be "no justification" for a middle tier of projects in future procurements. ELPC asserts the IPA must be given reasonable discretion to balance competing policy objectives, and it may well determine that creating a middle tier of projects is reasonable and prudent in future procurements. (ELPC Reply at 5)

ELPC supports the IPA's use of a credit deposit for bidders, but indicated that some stakeholders have expressed concern about the impact of the bid deposit requirement on small participants in the market. ELPC does not have a specific alternative bid deposit requirement to recommend. ELPC recommends that the IPA and the Commission closely monitor the upcoming procurement to evaluate whether the $10/REC bid deposit requirement appropriately balances the need to limit speculative bidding while also promoting maximum participation from the market. ELPC suggests the IPA can make adjustments in future procurements if necessary. (ELPC Reply at 5-6)

6. Staff's Position

Staff states that for 2015, the Proposed Plan includes renewable energy resource procurements only for RECs from photovoltaic and distributed generation, through two separate procurement events. Staff agrees with this recommendation. The IPA also notes that a plan for "a supplemental procurement of renewable energy credits from solar photovoltaics using up to $30 million from the Renewable Energy Resources Fund" is currently under development and will be filed with the Commission on or before October 28, 2014. (Staff Objections at 34-35)

With respect to the proposed procurement of RECs from distributed renewable generation devices, Staff says the IPA considered three different approaches. In Staff's view, the approach ultimately proposed by the IPA is the only one that can be consistent with the IPA Act and the PUA. Staff asserts it is the approach that is most similar to the IPA's established one-year REC procurement process -- conducting a single procurement competitive bid process with bids selected solely on the basis of price. (Staff Objections at 35)

According to Staff, the other two approaches included non-competitive "standard offers" for DG projects under 25 kW in capacity. Staff contends that if the General Assembly had desired a "standard offer" model for the procurement of RECs from DG projects under 25 kW, presumably, it would have made this clear. Staff also asserts the General Assembly could have simply amended the PUA to require utilities to file new or amended tariff sheets to implement such a program. Staff says there would have been no need for five year contracts or "third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." Staff concludes that the General Assembly wanted to continue to utilize the same type of

"competitive procurement processes in accordance with the requirements of Section 16-111.5 of the Public Utilities Act" that is required for all other IPA procurements. (Staff Objections at 35)

Among other things, Staff says that means utilizing a Procurement Administrator to: "serve as the interface between the electric utility and suppliers" (220 ILCS 5/16-111.5(c)(1)(iii)); "manage the bidder pre-qualification and registration process" (220 ILCS 5/16-111.5(c)(1)(iv)); and "administer the request for proposals process" (220 ILCS 5/16-111.5(c)(1)(vi)). Staff claims it also means utilizing a procurement process that includes, among other things, each of the following components: "Solicitation, pre-qualification, and registration of bidders" (220 ILCS 5/16-111.5(e)(1)); and a "request for proposals," setting forth "a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price" (220 ILCS 5/16-111.5(e)(4)). None of these required components are consistent with the standard offer approach included with the IPA's second and third options. For this reason, Staff recommends that the Commission approve the IPA's proposed option for procuring in the final plan. (Staff Objections at 35-36)

The Proposed Plan includes several renewable energy procurement proposals, one of which is to hold a procurement event through which Ameren and ComEd would purchase solar renewable energy credits to meet only the target SREC levels for the 2015-2016 delivery period.

ELPC and ISEA oppose the IPA's proposal. According to ISEA, "If left to just 1-year RECs, ISEA's concern is that the majority of these funds will leave the state to purchase available REC assets across the country." According to ELPC, "There is ample evidence from Illinois and elsewhere that new PV resources cannot be developed using one-year SREC contracts." Both intervenors recommend offering five-year contracts to potential SREC suppliers. Staff disagrees. (Staff Response at 4)

According to Staff, Illinois law does not require renewable energy resources purchased by utilities to be produced in Illinois, any more than it requires the natural gas purchased by utilities to be produced in Illinois. Staff argues ISEA's protectionist concern -- that the funds will leave the state to purchase non-Illinois RECs -- does not trump Illinois law, which expresses merely a preference for procuring renewable energy resources from Illinois or states that adjoin Illinois. (Staff Response at 4)

Staff also argues Illinois law does not require the IPA, let alone each IPA procurement event, to single-handedly bestow all that is necessary to incentivize investment in solar photovoltaic generating resources. Staff claims the solar power industry is replete with subsidization, tax incentives, grants, special utility rates, as well as renewable portfolio standards, like Section 1-75(c) of the IPA Act. Staff states IPA procurement events are only one prong of a multi-pronged, multi-jurisdictional approach of encouraging growth in the utilization of solar power. Staff also contends Illinois law makes no distinction between new and old generating resources when it comes to the purchase of RECs. Staff says a REC from a series of 10-year-old solar panels is just as

valid as a REC from a series of 1-year-old solar panels. Staff asserts both RECs represent the avoidance of generation from other resources (presumably resources that are not as well-accepted by policy makers). That is, the RECs themselves are all new. It is also worth noting that there are many wholesale and retail goods and services that are sold to both utilities and non-utilities that are not sold pursuant to long-term contracts. Staff insists many goods and services are sold without any explicit contracts. In Staff's view, ELPC's concern that new PV resources cannot be developed using one-year SREC contracts is to some extent exaggerated and to some extent misplaced. (Staff Response at 4-5)

Staff says the insistence of ELPC and ISEA on buying SRECs from new facilities may rule out the procurement of any additional SRECs specifically for the 2015-2016 period, as winning bidders would need some time to complete their projects. On the other hand, Staff believes there is an argument for not procuring any SRECs for 2015-2016, since the total REC target has already been met. (Staff Response at 5)

Staff also believes ELPC and ISEA fail to adequately address the budgetary issue. Without an assured base of eligible retail customers from whom to collect the costs incurred by the utilities over a five year period, Staff suggests the ELPC and ISEA proposal places at risk, depending on the details of the contract approved: retained eligible retail customers, existing renewable energy suppliers, and/or new renewable energy suppliers. (Staff Response at 5-6)

Staff says the risk of running out of funds in the middle of a 5-year contract term can be mitigated by reducing, at the time of the procurement event, the budget available. In Staff's view, how far to reduce the budget is a matter of judgment. (Staff Response at 6)

Staff recommends rejecting the ELPC and ISEA proposed 5-year SREC procurement. If the Commission decides to accept, in principle, the ELPC and ISEA proposal, Staff recommends that the budget for the new 5-year contracts be limited to one-half the total projected remaining budget available. In order to assure that the 5-year contract budgets are not exceeded, Staff says the contract prices would vary each year relative to each winning bidder's average winning bid price, in proportion to the initial year's budget. Staff provides a table with the budget caps rounded to the nearest $1000 and the contract price adjustments rounded down to the nearest tenth of 1 percent. (Staff Response at 6-7)

Staff states that to be clear, the budget caps it provides, which are based on the current forecast of funds available, would remain at the levels shown; they would not be updated during the life of the contracts. Staff also says the contract price adjustments it provides would also remain at the levels it shows. (Staff Response at 7)

Staff states that even though the budgets for the 5-year contracts it shows are equal to only one-half the projected remaining budget available, this does not guarantee that the actual remaining budget will be sufficient. Staff says the actual remaining

budget, which depends on the number and projected use of customers remaining on fixed-price utility supply ("eligible retail electric customers"), may not be enough to completely pay all amounts owed to REC suppliers under existing long-term contracts, REC suppliers under the new 5-year contracts, or both. Staff states that at the time the procurement took place (December 2010), the 20-year renewable contracts were expected to consume no more than a third of the projected REC budget for ComEd; and yet it became necessary to curtail those contracts after the first year due to customer switching activity depleting the actual REC budget. In Staff's view, it would be prudent for the new 5-year contracts to include provisions for curtailment, should Section 1-75(c) budgetary limitations make curtailments necessary, again. Staff opines that it would be fairer to make the new 5-year contracts subordinate to the existing long-term contracts. Staff believes it would be fairer to curtail the new 5-year contracts prior to curtailing the existing long-term contracts. In any event, Staff says the "pecking order" should be clearly specified prior to the new procurement event. (Staff Response at 7-8)

The IPA proposed to procure RECs associated with distributed renewable generation devices through a single procurement event in a competitive bid process in September 2015 with two categories of systems eligible to participate. The first category is for systems under 25 kW, the second for systems between 25 kW and 2 MW. Staff indicated its support for the proposal in its Comments and Objections to the IPA's Proposed Plan. (Staff Response at 8)

ISEA and ELPC express concerns that the IPA procurement approach would be cumbersome, confusing and possibly a deterrent to consumers, particularly in the <25kW market. They recommend the use of a third Party Administrator for systems <25kW and that a standard offer price be given to all small systems. (Staff Response at 8)

ISEA and ELPC also express concerns that if the cost of systems within the 25 kW to 2 MW range vary considerably, and the likely outcome of the IPA's proposal is that the smaller commercial systems within that range would be priced out of the market. They recommend splitting the 25 kW – 2 MW category into two: a 25 kW – 399 kW category and a 400 kW – 2 MW category.

ISEA and ELPC both disagree with the IPA's proposed $10/REC refundable credit deposit for bidders, and ISEA also opposes the IPA's proposed $500 non-refundable bid participation fee. Staff notes neither ISEA nor ELPC suggest alternatives. (Staff Response at 8-9)

ISEA and ELPC express concern with the IPA's proposed ban of "speculative" bids. They seek clarification on how and when bidders will be able to show that the projects included in their bids have been adequately identified. ISEA and ELPC express concerns about a pair of timing issues, as well, and seek clarification from the IPA about these issues.

Staff states that to some extent, it is sympathetic to the concerns of ISEA and ELPC. Staff believes some of their recommendations should be rejected. Staff notes they recommend use of a third Party Administrator for systems <25kW and that a standard offer price be given to all small systems. Staff claims to some extent, they misunderstand the IPA's proposal. Staff asserts there is nothing in the IPA's proposal that would prevent an aggregator from making its own standard offer to owners of systems <25kW. Staff asserts the issue is whether the IPA is permitted to make a "standard offer." (Staff Response at 9)

Staff believes the Commission should also reject the ISEA and ELPC proposal to split the 25 kW – 2 MW category into two sub-categories. Staff thinks ISEA and ELPC may be correct that smaller commercial systems within that range are more expensive per unit and would be priced out of the market. Staff complains that ISEA and ELPC present no coherent rationale for spending more to purchase the smaller systems within the 25 kW – 2 MW range. Staff states that while the law clearly expresses a preference for purchasing RECs from systems both above and below the 25 kW level, the law expresses no preference or requirement to split these systems into additional sub-categories. Staff contends the ISEA and ELPC proposal will only increase the cost of acquiring RECs from the 25 kW – 2 MW category, without any justification for doing so. (Staff Response at 10)

ComEd also comments on the IPA's proposal to conduct a procurement for RECs from distributed renewable energy generation devices. ComEd interprets the Plan as actually proposing two separate procurements: one for systems under 25 kW and another for systems between 25 kW and 2 MW. According to ComEd, such a process runs afoul of Section 16-111.5(e) of the PUA and Commission practice.

Staff agrees with ComEd's description of the Commission's past practice. Staff further agrees that the practice constitutes a well-reasoned means of implementing the provisions of Section 16-111.5(e) of the PUA and Section 1-75(c) of the IPA Act. According to Staff, that is not to say that this past practice is the only reasonable means of implementing those provisions. (Staff Response at 11)

In Staff's view, it is far from clear that the IPA's Proposed Plan is calling for two separate procurements, or if it is calling for a single procurement fully consistent with past practice. It appears to Staff that the IPA is planning on using a single procurement fully consistent with past practice. Staff notes the IPA refers to it as "a single procurement event." Staff also notes footnote 201 of the Proposed Plan states, "A similar method has been used by the IPA and its Procurement Administrator to select wind resources to satisfy the 75% target in past renewable energy resources procurement events under Section 1-75 of the IPA Act." Staff states that in order to implement two separate procurements, it would be necessary to specify a budget for each of the two system size segments, but the Proposed Plan does not do that. Staff says it refers to the "ACP funds being held as of May 31, 2014: for Ameren, the value is $5,556,580; for ComEd, the value is $7,842,658." Staff indicates it does not break up these funds into <25 kW segments and a 25 kW to 2 MW segments. Staff believes the

simplest approach would be the one consistent with past practice, as recommended by ComEd. Staff has no objections to that approach. However, if the Commission ultimately approves separate procurements for each of the two system size segments, then Staff believes it is imperative that the Commission, prior to those procurement events, approve separate budgets or authorize the IPA to adopt separate budgets. (Staff Response at 11-12)

Ameren also addresses the IPA's proposal to conduct a procurement for RECs from distributed renewable energy generation devices. Ameren proposes to link this procurement with the supplemental solar photovoltaic procurement that is described in Section 1-56 of the IPA Act.

As Staff understands it, Ameren's proposal would effectively divorce ComEd and Ameren from the distributed generation procurement, except as funding partners. Staff finds Ameren's proposal attractive in its relative simplicity. Staff also suggests that linking the regular Plan's proposed DG procurement with the supplemental solar photovoltaic procurement may reduce confusion among potential bidders and retail customers. Staff believes making the September DG REC procurement event contingent upon a June 2015 supplemental solar DG REC procurement being fully subscribed guards against conducting an exercise in futility. It is not clear to Staff what constitutes a June 2015 supplemental solar DG REC procurement being "fully subscribed," since the Draft Supplemental Photovoltaic Procurement Plan, which was distributed by the IPA on September 29, 2014, does not include any MWh targets and the budgets for each event are not divided into DG and non-DG segments. (Staff Response at 12-13)

Staff indicates it cannot support Ameren's proposal for the reason that it is not authorized by statute. Staff says the statute distinguishes between renewable energy resource purchases by the IPA (as described in Section 1-56 of the IPA Act) and renewable energy resource purchases by the utilities (Section 1-75(c) of the IPA Act and Section 16-111.5 of the PUA). (Staff Response at 12)

7. NRDC's Position

NRDC interprets AIC's position to be: the phrase "to the extent that it is available" could also be interpreted to mean to the extent that total RECs under existing contracts have not exceeded the total REC target. Second, AIC notes that such an expenditure would increase supply costs by approximately $0.50/MWh. (NRDC Response at 1)

NRDC argues that the Plan must require that AIC spend that portion of the remaining funds in its renewable resource budget as necessary to satisfy the unmet renewable subtargets set forth in Section 1-75(c)(1) of the IPA Act. NRDC says Section 1-75(c)(1) of the IPA Act provides in pertinent part, "[a] minimum percentage of each utility's total supply to serve the load of eligible retail customers….shall be generated from cost-effective renewable energy resources…." NRDC says by 2015, the IPA Act establishes a "minimum percentage" of "at least" 10%. The IPA Act continues, "[t]o the

extent that it is available…at least…[6%]…of the renewable energy resources used to meet these standards shall come from photovoltaics." (NRDC Response at 2)

In NRDC's view, the IPA Act cannot rationally be read to preclude further investment in the procurement of REC subtargets once the total REC target has been met. NRDC contends that by the explicit terms of the IPA Act, the total REC target is a "minimum" requirement, not a cap. According to NRDC, there is no limit as to the "availability" of renewable capacity that the IPA can procure. NRDC claims the "it" in the phrase, "to the extent that it is available," therefore, is referring to photovoltaic capacity. (NRDC Response at 2)

Other than availability, NRDC says the only other statutorily imposed limit on AIC's renewable resource budget is the rate cap imposed by Section 1-75(c)(2)(E). NREC argues that operating under the principle *expression unius est exclusion alterius*, AIC may not read into the IPA Act any other spending limitations. NRDC claims unless $0.50/MWh exceeds the statutory cap, the money in the renewable resources budget must be spent. (NRDC Response at 2)

According to NRDC, the statutory directives setting forth the IPA's 2015 obligations, to the exclusion of AIC's position, are as follows:

1. 10% or more of the capacity procured must have been produced by renewable resources; and
2. At least 6% of the renewable resources procured must have been produced by photovoltaics.
3. There are only two exceptions for not procuring renewable resources in the amounts required in 1 and 2:
    a. doing so would cause the statutory cap to be exceeded; and/or
    b. photovoltaic capacity in an amount required to reach 6% of the total renewable capacity procured is "not available." (NRDC Objections at 2-3)

NRDC takes no position as to whether the IPA's proposed one-year SRECs procurement is the most prudent use of AIC's remaining renewable resources budget. NRDC does, however, agree with many of ELPC's and ISEA's objections in this regard. NRDC suggests that the IPA hold a workshop to determine how the IPA can use renewable resource budgets and alternative compliance payments to promote the continued expansion of renewable resources in the best, simplest, and most user-friendly way. (NRDC Objections at 3)

8. The IPA's Position

ComEd and Ameren question whether the photovoltaic sub-target of the RPS must be met for a delivery year where both utilities have under contract sufficient RECs to meet overall target obligations. Section 1-75(c) of the IPA Act reads as follows:

> To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation and, beginning on June 1, 2011, at least the following percentages of the renewable energy resources used to meet these standards shall come from photovoltaics on the following schedule: 0.5% by June 1, 2012, 1.5% by June 1, 2013; 3% by June 1, 2014; and 6% by June 1, 2015 and thereafter.

The IPA finds it notable that the General Assembly included within the RPS a provision specific to the procurement of renewable energy resources from photovoltaics, added after its initial enactment, and specified that such procurement "shall" be made to "at least" a statutorily prescribed percentage. The IPA says the overall renewable energy resource targets are not enumerated as maximums; they also prescribe a minimum threshold amount. The IPA believes it has an obligation under the law to attempt to meet statutorily enumerated targets for the procurement of renewable resources from photovoltaics, even if overall REC targets are being met, and thus to propose this procurement. (IPA Response at 35-36)

Ameren references that the IPA "did not pursue any additional procurement of REC subtargets for 2013/2014" in its 2013 Procurement Plan, and the Commission did not disturb this finding. The IPA disagrees that past circumstances are instructive. The IPA says the 2013 Plan was developed against the backdrop of rapid customer switching to alternative retail electric suppliers through municipal aggregation. The IPA claims the unprecedented rate of switching left a cloud of uncertainty over projected future budgets, including whether the renewable resources budget would be sufficient to cover existing obligations (let alone new procurements). The IPA says while even mid-term future eligible retail customer load is uncertain, the IPA is confident in October 2014 that the renewable resources budget will be sufficient to support a 2015-2016 one-year SREC procurement. (IPA Response at 36)

The IPA appreciates that its proposed SREC procurement involves costs for eligible retail customers, as pointed out by Ameren. The IPA asserts, the balance between statutory RPS obligations and rate impacts is defined by statute, and the IPA says its proposed procurement would remain within the rate cap mandated by Section 1-75(c)(1) of the IPA Act while meeting procurement targets that "shall" be met at "at least" specified levels. (IPA Response at 37)

Ameren, ELPC, and ISEA object that a one-year SREC procurement will not develop new systems, with ELPC and ISEA suggesting five year contracts to incent photovoltaic system development. The IPA contends while the development of new generation is important to maintaining the "lowest total cost over time, taking into account the benefits of price stability," the year-to-year fluctuation of the Renewable Resources Budget exposes longer-term procurements to significant risk. The IPA states LTPPAs from 2010 already account for approximately 60% of Ameren's Renewable Resources Budget for the coming five years and approximately 80% for ComEd. The IPA suggests further diminishment in eligible retail customer load could

again produce curtailments for existing long-term obligations. In the IPA's view, this risk would only by exacerbated by additional new obligations, which would themselves be exposed to significant curtailment risk. (IPA Response at 37)

The IPA recognizes the goal sought through longer-term contracts, and notes that both its proposed distributed generation procurement and its draft supplemental solar photovoltaic procurement, which rely on collected funds rather than a revenue stream, propose contracts of at least 5 years in length. The IPA believes that risks introduced by load migration are simply too significant to justify longer-term contracts using the renewable resources budget. The IPA recommends ISEA and ELPC's arguments be rejected. (IPA Response at 37)

ELPC and ISEA also suggest escrowing funds as a way to avoid this problem. While well-intentioned, the IPA suggest this proposal is inconsistent with the rider recovery mechanism used by for the renewable resources budget, and may require a tariff change. The IPA believes this proposal should be rejected. (IPA Response at 38)

The IPA's proposed procurement of RECs from distributed generation systems using currently available hourly ACP funds is supported by ComEd, Staff, and ELPC. Ameren states that it "cannot fully endorse the proposal," and the ISEA "request[s] reconsideration for the renewable energy procurement process." (IPA Response at 38)

ComEd suggests that the proposed bid selection process be modified to select bids first on the basis of price, using any remaining budget to then introduce a preference for systems below 25 kW in size. The IPA believes this could be a sensible approach to balancing competing statutory directives, but not for this procurement. For this proposed DG procurement, the IPA argues it is unclear whether available hourly ACP funds will be exhausted prior to the target number of RECs being procured (and will remain unclear until bid evaluation). If the budget is exhausted before targets are met, the IPA claims ComEd's approach would result in a procurement exclusively determined on the basis of price. (IPA Response at 38)

The IPA states conflicts between statutes should be construed harmoniously. The IPA does not believe ComEd's proposed approach harmoniously balances provisioning for "selection of bids on the basis of price" and a competing requirement that "to the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity." The IPA contends ComEd's approach may result in outcomes where system size plays no factor in any bid's selection, and could result in zero RECs procured from systems below 25 kW in size. The IPA believes in a more harmonious reading reflected in its proposed approach. (IPA Response at 38-39)

ComEd also suggests that bids of 1 MW in size should be selected at a single price per REC for each block bid, rather than the IPA's proposed approach of selecting individual systems within bids at potentially different price points. According to the IPA, at issue, again, is the need to balance competing objectives. The IPA claims it is

seeking to develop a procurement process accessible to the owners and developers of all DG system sizes, including small, residential rooftop photovoltaic systems. The IPA suggests assembling disperse, small DG systems into 1 MW bids may be extremely challenging without larger systems making up some portion of the bid, but cost structures between small and large systems vary significantly. (IPA Response at 39)

The IPA states all winning bids must meet confidential benchmarks. Given the different cost structures between large and small systems, the IPA suggests that the factors that contribute to the benchmarks for each size category for evaluation will vary. The IPA says for sub-25 kW systems and 25 kW to 2 MW systems to be evaluated separately, systems would need to either be a) segregated into bids exclusively made up of systems of a specific size category, or b) evaluated in accordance with the size-specific benchmark as individual systems within a single bid. (IPA Response at 40)

The IPA says it could then require the selection of only full bids, and require for those bids to be made up exclusively of systems either sub-25 kW in size or 25 kW to 2 MW in size. While consistent with ComEd's suggested approach, the IPA believes this approach raises the original challenge of assembling full 1 MW blocks of small DG systems. As the law calls for 50% of RECs to come from systems below 25 kW in size, the IPA believes developing a procurement model that creates barriers for small system participation would be contrary to the preference articulated in the law. (IPA Response at 40)

The IPA claims the need to accommodate these smaller systems informed the decision to propose the selection of systems within bids. The IPA says this approach allows for bids to be composed of systems both above and below 25 kW in size, thus a) increasing the likelihood that sub-25 kW systems may find their way into a full 1 MW bid, b) allowing for the statutory size preference to be applied in bid selection at the system level, and c) allowing for pricing of RECs that reflect distinct system cost structures. (IPA Response at 40)

The IPA indicates it is sensitive to ComEd's concerns. The IPA suggests an approach which calls for the selection of systems within bids, rather than the full bids themselves, may indeed increase the contract administration burden faced by the utilities. The IPA asserts alleviating that burden must be balanced with meeting other goals of this procurement. To this end, the IPA proposes that the selection of systems within bids could occur in 100 kW blocks, with price terms specific to those individual blocks. Additionally, the IPA proposes that aggregators may contract with system owners at different REC price points and systems may be selected at different price points, but with a single blended average REC price for an aggregator's contract with ComEd. The IPA suggests this may better balance the need to promote small system participation while alleviating administrative burdens on the utilities. (IPA Response at 40-41)

The IPA insists ComEd is incorrect that its proposed approach "would clearly be in conflict with the provisions of Section 1-75(c) of the IPA Act." The IPA says Section

1-75(c)(1) of the IPA Act requires that third-party aggregators "aggregate distributed renewable energy into groups of no less than 1 MW in size" and "administer contracts with individual distributed renewable energy generation device owners." The IPA claims its approach relies on aggregators to develop bids of at least 1 MW in size and contract with system owners for the provision of RECs. While ComEd may prefer that systems not be priced individually and selected independently within a group of 1 MW (or more), the IPA believes its approach meets Section 1-75(c)(1)'s requirements. (IPA Response at 41)

The IPA claims it is sensitive to concerns posed by ELPC and ISEA that its proposed DG procurement may be overly complicated and may limit participation from small system owners. The IPA argues that because the law calls for the use of third-party aggregators, individual small system owners are unlikely to interface with the IPA's procurement process. The IPA asserts they would interface with an aggregator with whom they have a contract for the sale of RECs. While the IPA hopes to remove barriers where possible to participation by small system owners, it says barriers cannot be removed in a manner inconsistent with the law. (IPA Response at 41-42)

To provide increased clarity, ISEA recommends "the use of a 3rd party administrator for systems <25 kW in size and that a standard offer price be given to all small systems." The IPA claims it is unclear from this proposal who is bidding on what and how, let alone how the administrator and any "standard offer price" may be chosen. According to the IPA, this proposal raises serious questions about consistency with the PUA, and no attempt is made to reconcile this proposal with the statutory direction provided in Section 16-111.5 of the PUA. Absent a clear and legally supportable alternative proposal, the IPA believes this recommendation should be not be adopted. (IPA Response at 42)

The IPA states that even if the use of a program administrator and/or a single offer price was legally authorized, it is unclear whether further clarity or certainty would result. Essentially, a third party administrator would serve the same role as a third-party aggregator serves under the IPA's proposed approach. The IPA claims the primary difference is that ISEA is seeking for the IPA to select that aggregator, and for there to be only one. The IPA suggests this may provide advantages in terms of simplicity and transparency, but also introduces risk. The IPA says a single aggregator could yield market power and require unreasonable administrative costs. The IPA believes that the market may be in a better position to develop or determine aggregators that can bid competitively in the IPA's procurement process, and that competition between aggregators may drive more competitive and targeted offers to system owners. (IPA Response at 42)

According to the IPA, ELPC's objections request that the IPA eliminate its 1 MW minimum bid requirement and "simply award contracts in no less than one MW blocks." The IPA is confused by the proposal. The IPA says the distinction between a 1 MW "bid" and a 1 MW "block" is not explained; the IPA's "block" energy procurements involve "bids" tailored to the IPA's established energy "block" size. The IPA states that

essentially, the "block" is what is sought, while the "bid" is what is offered. In the IPA's view, as articulated in ELPC's objections, it is unclear how "a process to award contracts in blocks of 1 MW capacity" would be more accessible to small system owners. (IPA Response at 42-43)

With respect to the creation of sub-categories between 25 kW and 2 MW, the IPA is sensitive to concerns raised that its proposed procurement approach may not properly accommodate mid-sized commercial systems. The IPA claims it is unclear whether a 35 kW system owner that may downsize to participate in the sub-25 kW category, a category mandated by statute, would feel comfortable competing against 200 kW systems or 400 kW systems. The IPA also says the introduction of sub-categories could drive system owners planning a 225 kW system to downsize to 200 kW to meet that lower sub-category threshold. The IPA asserts such gaming is inevitable, and may only be exacerbated by the introduction of further sub-categories. (IPA Response at 43)

Given the small budget associated with this procurement and the need to cost-effectively meet statutory DG procurement goals, the IPA believes that the development of system size sub-categories within the 25 kW to 2 MW category may be better suited for its supplemental procurement under Section 1-56(i) of the IPA Act, and notes that its Section 1-56(i) procurement features a larger budget and no statutory REC procurement target. (IPA Response at 43)

Both ISEA and ELPC believe the IPA's proposed credit deposit of $10 per REC is too onerous and may create a barrier to participation. While neither offers an alternative proposal, the IPA is sensitive to these concerns and would consider a downward revision of this requirement. (IPA Response at 43-44)

ISEA & ELPC also seek clarification on a variety of items; the IPA provides its clarification below:

- <u>Documents used for project identification</u> – Absent specific alternative proposals, the appropriate documentation to establish project development will be determined through the standard form contract development process after entry of the Commission's Order.
- <u>Cancellation for non-performance</u> – The contract amount would only be reduced for non-performance and not outright cancelled.
- <u>Contract length/performance start date</u> – To reduce administrative burdens associated with distinct contract start dates and to provide further process clarity, the IPA now proposes that contracts run for at least full length of 5 years, as measured by the first date of the 2016-2017 delivery year through the last date of the 2020-2021 delivery year. Systems must be operational and registered with PJM-GATS or M-RETS by June 1, 2016. While the IPA had previously proposed that some RECs must be delivered within the 2015-2016 delivery year, to ensure uniform contract length and to promote clarity and certainty, the IPA now

proposes a firm 5-year delivery schedule with an established start and end date coinciding with the IPA's delivery year.
(IPA Objections at 44)

Ameren offers that the Commission "order Ameren Illinois to transfer" hourly ACP funds to the IPA, with the IPA acting as the contractual counterparty to the DG procurement. The IPA suggests even if such a transfer of funds was legal, it is unlikely that the utility's requirement that "a minimum percentage of each utility's total supply to serve the load of eligible retail customers" be spent on RECs would be satisfied through contracts owned by the IPA. While the IPA appreciates the simplicity offered by pooled procurement, the IPA believes a better solution may lie in legislation to realign the streamline this statutory scheme. (IPA Response at 44-45)

Ameren also requests that the Commission stipulate that the IPA's proposed DG procurement "should be contingent on the June 2015 DG REC portion of the supplemental solar procurement being fully subscribed." The IPA objects to this proposal. The IPA argues at a minimum, under the law, the supplemental solar procurement is required to feature different counterparties and different eligibility requirements, and the IPA's proposed DG procurement is not limited to photovoltaic resources. The IPA says other differences may be approved by the Commission in separate docketed proceedings featuring separate records, and there may be many reasons why parties may choose to participate in one procurement but not another. The IPA also asserts the IPA's June 2015 REC procurement event is merely one proposal in a draft plan currently under revision; one which has not yet been filed with the Commission, let alone approved. (IPA Response at 45)

The RS note that the language in the executive summary of the 2015 Plan and in Section 8 of the Plan are not completely consistent and offer three clarifying points. The IPA agrees with those points and supports updating the Final Plan accordingly. The RS also offer an exception regarding the date of the calculation of the balance of available hourly ACP funds, suggesting it should be May 31, 2015 and not March of 2015. The IPA agrees with that exception and supports changing the date to May 31, 2015. (IPA Response at 45-46)

The RS raise an objection related to the delivery of curtailed RECs when a prior-year shortfall exists. In the IPA's view, this appears to be a contract issue between the RS and ComEd related to the curtailment for the 2014-2015 delivery year, and not germane to the 2015 Procurement Plan. The IPA takes no position on this objection. (IPA Response at 46)

The IPA continues to agree with arguments offered by ELPC, NRDC, and ISEA regarding the binding nature of the technology-specific "carve-outs" present in Section 1-75(c)(1) of the IPA Act, and disagrees with comments by Ameren and ComEd that such targets are merely aspirational. (IPA Reply at 15)

The IPA says no party argues that the minimum percentages, which "shall" be met "at least" at specified amounts, can simply be disregarded. (IPA Reply at 15)

Section 1-75(c)(1) of the IPA Act also establishes technology specific sub-targets, or "carve-outs," as follows:

> To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation and, beginning on June 1, 2011, at least the following percentages of the renewable energy resources used to meet these standards shall come from photovoltaics on the following schedule: 0.5% by June 1, 2012, 1.5% by June 1, 2013; 3% by June 1, 2014; and 6% by June 1, 2015 and thereafter.

The IPA says ComEd and Ameren argue that these minimum sub-target percentages, which also "shall" be met "at least" at specified amounts, are merely "aspirational" goals which can be disregarded, with ComEd stating that no legal requirement compels meeting sub-targets should overall targets be met. The IPA claims as offering contradictory definitions to "at least" and "shall" within the same sub-section of a law is nonsensical and this argument must be rejected. (IPA Reply at 15-16)

Parties arguing that the IPA is not compelled to procure RECs from photovoltaics make two additional arguments. The first is a claim that "to the extent available" could mean "available" when meeting only the bare minimum of the overall renewable energy resources requirement. But as the overall targets are minimum procurement targets ("at least"), the IPA believes the obvious reading of Section 1-75(c)(1) is that "available" refers to "available" generally for procurement within the confines of the statutory 2.015% rate impact cap. The IPA claims a contrary reading would turn a minimum threshold ("at least") into a maximum cap ("no more than"). If the General Assembly had sought such a cap on renewables procurement, the IPA believes it would have so specified. (IPA Reply at 16)

The IPA says a second argument is that conducting a SREC procurement would be unwise, as it would feature additional costs to eligible retail customers. The IPA maintains the balance between increased costs and the need to meet renewable energy procurement targets is struck by statute in establishing a 2.015% rate impact maximum. The IPA is not proposing to exceed this cap, and no party argues otherwise. If the General Assembly had sought a different rate impact balance, The IPA believes it would have so specified. (IPA Reply at 16)

The IPA recognizes that meeting technology-specific targets creates challenges not present with meeting overall RPS targets. The IPA says this requires year-to-year balancing to assess needs relative to resources already under contract. According to the IPA, that assessment must then be analyzed against a dynamic renewable resources budget subject to fluctuation from customer switching trends. In the IPA's view, this is a manageable challenge. The IPA believes it is important that these concerns do not mute the clear directive in statute that "at least" a specified percentage of RECs from photovoltaics "shall" be procured. (IPA Reply at 16-17)

ISEA and ELPC continue to argue in Response that any resulting contracts should be greater than in length than one year. The IPA disagrees with these parties and supports the SREC procurement proposal outlined in its 2015 Plan. Staff likewise disagrees with ISEA and ELPC, but offers a number of conditions it believes should apply to a 5-year contract proposal. The IPA agrees with Staff's analysis of the necessary budget and curtailment provisions that would apply to a 5-year SREC procurement. The IPA states while such terms are necessary, a reduction in budget may reduce the likelihood that minimum statutory thresholds for SREC procurement are met, illustrating another challenge with longer-term contracts. (IPA Reply at 17)

In Response, ELPC seeks a change to the IPA's DG procurement proposal by allowing for bidders to "aggregate the bids into groups of 1 MW" at the "back-end" of the IPA's proposed procurement. The IPA is confused by this proposed modification. The IPA states at a minimum, it is unclear what entity or entities are proposed to serve as the contractual counterparty in grouping winning bids through a "back-end" 1 MW aggregation, what party is responsible for determining this "back-end" grouping, and how any new counterparty would consent to be contractually bound post-bid selection to fulfill another bidder's bid. The IPA believes without further clarification and detail, this proposal must be rejected. (IPA Reply at 17)

ISEA continues to advocate for the adoption of a "program manager" model, and makes policy arguments about the necessity of a distinct procurement design given that the distributed solar market is "structured very differently than conventional energy markets." The IPA is sympathetic to these concerns. The IPA's procurement process is designed, first and foremost, to accomplish its primary objective of reliably procuring energy for eligible retail customers. The IPA is proposing to meet this objective primarily through twice-annual procurements of block energy products in 8-hour and 16-hour 25 MW blocks. The IPA claims no objective observer would suggest that a process for procuring these products is likely to also be a process well-suited for procuring RECs using long-term contracts from small photovoltaic rooftop installations. The IPA asserts distinct products and different market participants often necessitate different processes to maximize efficiency and participation; this is no different. (IPA Reply at 17-18)

The IPA says no party has raised an argument that the strictures of Section 16-111.5 of the PUA, which spells out the necessary features of the IPA's procurement process, do not apply to the IPA's procurement of DG RECs using hourly ACP funds collected and spent pursuant to Section 1-75(c)(5) of the IPA Act. The IPA also says no party has attempted to explain how a procurement process so fundamentally distinct from the DG procurement proposed by the IPA would be consistent with Section 16-111.5's requirements. So while the IPA is sympathetic to these concerns, absent compelling arguments that the governing law does not apply or should be interpreted differently, the IPA believes these arguments must be rejected. (IPA Reply at 18)

In Response, Staff notes that the IPA is not proposing "two separate procurements" as ComEd mentions, but adds that the IPA may wish to clarify further. The IPA says it is not proposing "separate procurements" for systems below 25 kW and 25 kW to 2 MW. Instead, the IPA is proposing that system size be employed as criteria in evaluating a bid in a manner different than suggested by ComEd; that process has since been explained further by the IPA in its Response. (IPA Reply at 18)

Ameren and now ComEd argue for adoption of a proposal whereby hourly ACP funds to be spent on procured DG RECs would be transferred to the IPA for procurement, with the IPA serving as the counterparty to resulting 5-year DG REC contracts. The IPA does not oppose this proposal on policy grounds. It offers potential synergies with the IPA's proposed supplemental procurement under Section 1-56(i) of the IPA Act, adding clarity to market participants and reducing associated procurement costs. (IPA Reply at 19)

The IPA claims transactions with state agencies can be complex. The IPA says it cannot simply take funds and apply them as directed by the contractual terms of a transfer (as, say, a designated private agent could). The IPA says its power, authority, and limitations are drawn from law, not from contract. Even assuming this transaction was possible, it is unclear to the IPA whether the procurement itself could operate consistent with the law, both because such a procurement may not result in the utilities technically meeting DG procurement targets, or because such a process may be inconsistent Section 1-75(c)(5)'s directive that hourly ACP funds be spent "on the purchase of renewable energy resources to be procured by the electric utility . . ." As the IPA is unsure whether it could be a party to such a transaction, unclear on whether it could spend the money as directed, and skeptical that any resulting procurement would operate consistent with the law, it cannot endorse this proposal. (IPA Reply at 19)

ComEd proposes new language responsive to Objections by the RS regarding how available hourly ACP funds designated for a DG REC procurement would intersect with a potential purchase of curtailed RECs. The IPA understands any disagreement as two parties seeking different means (through revised Plan language) to arrive at the same basic end. While the IPA endorsed the RS' proposed clarifications in Response, it appears that ComEd's proposed language is more consistent with the law and the utilities' actual hourly ACP collection process, and the IPA thus supports ComEd's proposed revisions to page 3 of the Plan. (IPA Reply at 19-20)

In its brief on exceptions the IPA proposed a lowering of the deposit fee to $8/REC to be consistent with the Supplemental PV Procurement Plan. The IPA says this adjustment was made to mathematically adjust for the changed capacity factor used in that Plan. The IPA also proposed allowing for the use of a letter of credit. (IPA BOE at 8)

The IPA insists it may not simply "conduct a procurement" pursuant to some abstract, unidentified authority, taking title to RECs for transfer and serving as a contractual conduit for the delivery of funds. In the IPA's view, the relevant question for

the IPA is not what statutory provisions prohibit it from entering into binding contracts on another party's behalf, it is what provisions allow it. (IPA RBOE at 12)

The IPA notes that the RS' second exception concerns at what date the balance of hourly customer ACP funds should be taken for determining the proposed DG procurement budget. Citing the Commission's budget determinations for the purchase of curtailed RECs from hourly ACP funds pursuant to its Order on Rehearing in Docket No. 13-0546, the RS believe that date should be May 31, 2015. (IPA RBOE at 14)

Upon review, the IPA believes that the phrase "prior year" used in this context could refer to either May 31, 2014, or May 31, 2015. The IPA says use of March forecasts for updating procurement volumes and budgets has become a feature of the IPA procurement process, and rolling forward the date of the determination of funds for the DG procurement budget would achieve a similar end (and would likely provide a larger budget for the procurement). Given the IPA's proposed September 2015 DG procurement schedule, the IPA says either approach is workable for it in practical terms. The IPA thus does not object to the RS' proposal and can see its merits, but given the ambiguity in the law, takes no position as to which approach should be adopted. (IPA RBOE at 14)

9. Commission Analysis and Conclusions

As an initial matter, the Commission observes that especially with regard to the procurement of renewable resources, the IPA has a particularly difficult task. The provisions of the PUA and the IPA Act are, unfortunately, complex, unclear, and seemingly constantly changing. In addition, the IPA has to balance competing statutory objectives and attempt to respond to parties with interests that are far from aligned. The Commission commends the IPA for its efforts and the results it has produced.

The Commission will first turn to the IPA's proposal for a one-year SREC procurement which is opposed by ELPC, ISEA, ComEd, and Ameren. ComEd and Ameren contend that the SREC procurement is unnecessary and will result in utility customers paying for more RECs than the amount targeted by Section 1-75(c) of the IPA Act. In addition, Ameren, ELPC, and ISEA argue that a one-year SREC procurement will do little to encourage the development of new solar facilities in Illinois. They also suggest it is inconsistent with the IPA's other procurement activities.

As the IPA correctly points out, it has competing statutory obligations to encourage the development of new solar facilities while assuring that it does so at a reasonable cost. Staff also correctly notes that there many ways in which government encourages the development of solar facilities. The Commission's primary concern with the ELPC and ISEA proposal is the lack of stability in the funding source for this particular procurement and therefore the ELPC and ISEA proposal to replace the one-year SREC procurement with a longer term DG REC procurement is rejected. The Commission concludes that the IPA's proposal for a one-year SREC procurement is clearly supported by the record and should be approved.

ISEA recommends the use of a third party administrator for systems <25 kW in size and that a standard offer price be given to all small systems. The IPA and Staff believe this proposal raises serious questions about consistency with the PUA, and no attempt is made to reconcile this proposal with the statutory direction provided in Section 16-111.5 of the PUA. The Commission finds that there is no statutory provision that would allow for a standard offer price to be provided to small facilities. As a result, ISEA's recommendation must be rejected.

ELPC recommends the IPA's proposal be modified to eliminate its 1 MW minimum bid requirement and simply award contracts in no less than one MW blocks. The IPA believes it is unclear how or why ELPC's proposal would be more accessible to small system owners than the IPA's proposal. The IPA also states that it is unclear what entity or entities are proposed to serve as the contractual counterparty in grouping winning bids through a "back-end" 1 MW aggregation, what party is responsible for determining this "back-end" grouping, and how any new counterparty would consent to be contractually bound post-bid selection to fulfill another bidder's bid.

The Commission is somewhat sympathetic to those parties who propose modifications to the Plan in attempt to encourage the development of small facilities. As previously noted; however, the IPA and the Commission have competing statutory objectives. In this instance, the Commission concludes that ELPC has not adequately explained or justified its proposed change to the IPA's proposed Plan. As a result, the Commission declines to adopt the ELPC' proposed modification for purposes of the Plan approved herein.

ISEA and ELPC also propose to split the 25 kW – 2 MW category into two sub-categories. Staff believes that ISEA and ELPC present no coherent rationale for spending more to purchase the smaller systems within the 25 kW – 2 MW range. Staff contends the ISEA and ELPC proposal will only increase the cost of acquiring RECs from the 25 kW – 2 MW category, without any justification for doing so. The IPA suggests the introduction of sub-categories could drive system owners planning a 225 kW system to downsize to 200 kW to meet that lower sub-category threshold. The IPA asserts such gaming is inevitable, and may only be exacerbated by the introduction of further sub-categories.

Again, the Commission is somewhat sympathetic to the rationale underlying the ISEA and ELPC proposal to create subcategories. In this instance, ISEA and ELPC have not provided adequate support for their proposal. The Commission believes both Staff and the IPA have identified significant potential problems with the proposal. The Commission, therefore, declines to adopt the proposed modification made by ISEA and ELPC for purposes of the Plan approved herein.

ComEd believes that the proposed bid selection process must be modified to select bids first on the basis of price, using any remaining budget to then introduce a preference for systems below 25 kW in size. ComEd argues the IPA's approach would

be in conflict with the provisions of Section 16-111.5(d) of the PUA. The IPA believes this could be a sensible approach to balancing competing statutory directives, but not for this procurement. For this proposed DG procurement, the IPA argues it is unclear whether available hourly ACP funds will be exhausted prior to the target number of RECs being procured. If the budget is exhausted before targets are met, the IPA is concerned ComEd's approach would result in a procurement exclusively determined on the basis of price.

The IPA does not believe ComEd's proposed approach harmoniously balances provisioning for "selection of bids on the basis of price" and a competing requirement that "to the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity." The IPA contends ComEd's approach may result in outcomes where system size plays no factor in any bid's selection, and could result in zero RECs procured from systems below 25 kW in size. The IPA believes in a more harmonious reading reflected in its proposed approach.

Having reviewed the IPA Act, the parties arguments, and the circumstances present for the proposed procurement, the Commission finds the IPA's proposal the most reasonable. ComEd's proposal could easily result in a procurement from only facilities larger than 25 kilowatts, which is not consistent with the General Assembly's intent. As the IPA suggests, the ComEd proposal may deserve consideration in future procurements given a possible change in circumstances. In this instance; however, the IPA's proposal must be adopted.

ComEd also suggests that bids of 1 MW in size should be selected at a single price per REC for each block bid, rather than the IPA's proposed approach of selecting individual systems within bids at potentially different price points. The IPA suggests an approach which calls for the selection of systems within bids, rather than the full bids themselves, may increase the contract administration burden faced by the utilities. The IPA asserts alleviating that burden must be balanced with meeting other goals of this procurement. To this end, the IPA proposes that the selection of systems within bids could occur in 100 kW blocks, with price terms specific to those individual blocks. Additionally, the IPA proposes that aggregators may contract with system owners at different REC price points and systems may be selected at different price points, but with a single blended average REC price for an aggregator's contract with ComEd. The IPA suggests this may better balance the need to promote small system participation while alleviating administrative burdens on the utilities.

In its Reply, ComEd states assuming this means that the contract between the aggregator and utility reflects a minimum of 1 MW for a single price (derived from "blending"), ComEd says this is the position it advocated in its Objections and Response. ComEd says the aggregator construct facilitates small contract amounts and varying prices between aggregators and suppliers. It appears to the Commission that the IPA and ComEd are now in agreement on this issue; and the Commission hereby approves that agreement for purposes of this Plan.

Both ISEA and ELPC believe the IPA's proposed credit deposit of $10 per REC is too onerous and may create a barrier to participation. The IPA noted that neither offered an alternative proposal, saying it is sensitive to these concerns and would consider a downward revision of this requirement. In its Reply, ISEA recommends that the IPA require a credit deposit of $5 per REC for participation. Unfortunately, due to the late nature of the ISEA proposal no party had an opportunity to reply, however on exceptions the IPA clarified that the comparable deposit in the Supplemental PV Plan has been adjusted to $8/REC and that letters of credit had been added as an alternative to a cash deposit. In order to maximize harmony between the plans, the Commission adopts an $8/REC deposit for this procurement as well as allowing for the use of letters of credit.

Ameren recommends that the Commission order Ameren to transfer hourly ACP funds to the IPA, with the IPA acting as the contractual counterparty to the DG procurement and that any concern with statutory compliance could be addressed in the implementation phase through a contractual mechanism. Both Staff and the IPA believe such a transfer of funds is not legal, and the IPA believes a better solution may lie in legislation to realign and streamline this statutory scheme. ComEd is supportive of the Ameren proposal and does not fully understand the resistance by Staff and IPA. It appears to the Commission that Staff has correctly interpreted the statutes in that Section 1-56 of the IPA Act governs renewable energy resource purchases by the IPA, while Section 1-75(c) of the IPA Act and Section 16-111.5 of the PUA govern renewable energy resource purchases by the utilities. The Commission concludes that Ameren's proposal cannot be adopted.

Ameren and ComEd also request that the Commission stipulate that the IPA's proposed DG procurement should be contingent on the June 2015 DG REC portion of the supplemental solar procurement being fully subscribed. The IPA argues under the law, the supplemental solar procurement is required to feature different counterparties and different eligibility requirements, and the IPA's proposed DG procurement is not limited to photovoltaic resources. The IPA says other differences may be approved by the Commission in separate docketed proceedings featuring separate records, and there may be many reasons why parties may choose to participate in one procurement but not another.

The Commission is sympathetic to Ameren's desire to preserve resources and avoid wasting time. In this instance; however, given the different nature of the two proposed procurements, there is not adequate justification for making one procurement conducted under one statutory provision in any way contingent on a prior procurement conducted under a different statutory provision. Ameren's proposal is therefore rejected.

The RS proposed language regarding how available hourly ACP funds designated for a DG REC procurement would intersect with a potential purchase of curtailed RECs, including a revised version of item 10 in the "Action Plan on page 6 of

the Plan. ComEd proposed different language, for page 3 of the Plan, intended to accomplish the same goal but specifying dates for the determination of the available hourly ACP balances that the RS disputed. While the IPA endorsed the RS' proposed clarifications in Response, it appears to the IPA that ComEd's proposed language is more consistent with the law and the utilities' actual hourly ACP collection process, and the IPA supports ComEd's proposed revisions to page 3 of the Plan. The RS opposed ComEd's proposal. Given that the two competing sets of language are intended and apparently would achieve the same goal, the Commission approves the language proposed by ComEd and endorsed by the IPA.

The RS raised concerns arising from the inability to produce the full amount of curtailed 2014-2015 RECs by May 31, 2015 for delivery to ComEd where the supplier began the 2014-2015 delivery year in a shortfall make-up position from 2013-2014. The RS believes the contract for purchase of 2014-2015 curtailed RECs should not serve as a template for future years' contracts. The RS argues that the Commission should order that the problem the RS has identified be corrected for future years. The RS says the sole purpose of the contract is to effectuate the Commission's Rehearing Order in Docket No. 13-0546. The RS believes the Commission should direct ComEd to make changes in the terms under which it purchases the curtailed RECs.

ComEd argues that the RS negotiated and signed contracts with ComEd that state that the curtailed RECs that will be purchased are those that are curtailed between June 1, 2014 and May 31, 2015, and the Commission cannot revise the contracts without violating constitutional principles. ComEd also says the contracts were reviewed and approved by the IPA and Commission Staff. ComEd states that if FPL Energy operates at or above the level to which it committed in its original LTPPA contract, it will generate enough curtailed RECs to receive its full allotment of hourly ACP funds.

As the Commission understands it, the RS do not seek to have an existing contract modified; instead, they want the Commission to intervene with respect to future contracts regarding curtailed RECs. The Commission alsoappreciates, however, that there are numerous suppliers and, therefore, efficiencies to be gained in maintaining a standard contract. To balance these interests, in the future, each supplier that seeks changes to the standard contract shall direct its comments to the utility, the IPA and Staff, rather than just the utility, and the utility, IPA and Staff shall consider the comments and, if appropriate, work out changes to the standard contract (on behalf of all suppliers).

E. Capacity Purchases

1. Ameren's Position

Ameren supports the Plan proposal to solicit capacity for it for the second and third delivery years. However, in reference to the quantity of capacity to be solicited, Ameren has several recommendations. (Ameren Objections at 1)

Ameren indicates the Plan references soliciting 50% of forecasted requirements for the second plan year and 25% of forecasted requirements for the third plan year, while in other cases the Plan references “at least” 50% of forecasted requirements for the second plan year and “at least” 25% of forecasted requirements for the third plan year. Ameren recommends that the Plan remove any potential for ambiguity by eliminating “at least” and provide the specific percentage quantity to be solicited. (Ameren Objections at 2)

Ameren notes that on page 2 of the Plan it states: “Additionally, the IPA recommends purchasing capacity to satisfy a portion of the capacity requirement for Ameren Illinois for the second delivery year and potentially, subject to the consensus of the IPA, ICC Staff and Procurement Monitor, 25% of the forecast requirement for the third delivery year.” On page 3, this proposal and associated quantities is illustrated in Table 1-2: Summary of Capacity Hedging Strategy. (Ameren Objections at 2)

Ameren interprets the proposal on pages 2 and 3 as a recommendation in favor of soliciting 25% of capacity for the third delivery year subject to consensus of the IPA, Staff, and Procurement Monitor. Ameren is concerned that the statement on page 94 could be interpreted as the IPA not being in favor of a solicitation, but instead pre-approving a solicitation assuming the IPA, Staff and Procurement Monitor reach consensus. While the difference in the statements may be subtle, Ameren believes the potential for ambiguity exists and therefore the statement on page 94 should be modified to make clear the IPA’s intent. (Ameren Objections at 2-3)

Ameren does not agree there is a need for the procurement associated with the third delivery year to contain a contingency that calls for consensus between the IPA, Staff, and Procurement Monitor. Ameren says the differences between the MISO and PJM capacity markets leads to considerable price uncertainty for Ameren customers relative to ComEd customers. According to Ameren, in a year where resourced adequacy demand exceeds supply within MISO, Ameren customers could be exposed to dramatic and sudden capacity price increases which would increase the total price of supply. Ameren states that while it appreciates the IPA proposing a capacity procurement for Ameren customers consistent with Ameren’s comments to the draft Plan, it is concerned that the proposal may not go far enough, especially if the contingency for the third delivery year procurement is approved. (Ameren Objections at 3)

Ameren recommends removal of the proposal for consensus associated with the procurement of capacity for the third delivery year. Ameren’s rationale is that both the second and third delivery year procurements already have a built-in contingency because confidential benchmarks will be developed, and should capacity offers from suppliers exceed these benchmarks, the rejection of some or all offers could occur. Ameren provides specific language changes that it recommends for page 94 of the Plan. (Ameren Objections at 3-4)

To the extent that the Commission disagrees, at the least Ameren believes it and the Procurement Administrator should be added to the list of parties required for consensus regarding the procurement of capacity for the third delivery year. For the removal of doubt, this secondary recommendation is not suggesting that Ameren participate in the capacity price benchmarking process. Ameren again provides specific language under its secondary recommendation for page 94 of the Plan. (Ameren Objections at 4)

The IPA clarifies that while the procurement of Ameren capacity for 2016/2017 is planned, the IPA is seeking only Commission pre-approval for a 2017/2018 procurement should conditions warrant and the IPA, Staff, and the Procurement Monitor reach consensus in 2015. The IPA offers to adopt an alternative proposal where Ameren and the Procurement Administrator are added to the list of parties that will determine whether a 2017/2018 capacity procurement is warranted in 2015.

Ameren appreciates the willingness of the IPA to adopt the alternative proposal, but continues to support Ameren's primary proposal that the IPA procure 25% of capacity for 2017/2018 without the need for consensus (based on the belief that benchmarks already provide the desired contingency). According to Ameren, the IPA has yet to credibly dismiss Ameren's recommendation that the better play is to procure 25% of capacity for 2017/2018 without the need for any consensus. If the Commission disagrees, consistent with the alternative proposal, Ameren believes it and the Procurement Administrator should be added to the list of parties who will decide whether to have a 2017/2018 procurement. (Ameren Reply at 1)

2. Staff's Position

Staff indicates for ComEd, the IPA proposes that ComEd continue to meet capacity obligations directly from PJM. PJM acquires capacity obligations from suppliers through a series of auctions that begin three years prior to the delivery year. In contrast, MISO's capacity auctions are held only a couple of months prior to the delivery year. Staff says Ameren customers would be exposed to greater price risk than ComEd customers by relying exclusively on the RTO for meeting capacity requirements. Staff also says the IPA cites other factors that highlight the risk associated with relying solely on MISO's auctions for determining Ameren's cost of capacity. For all these reasons, the IPA recommends using an RFP to acquire a portion of Ameren's expected future capacity requirements. (Staff Objections at 27)

Generally, Staff is not opposed to this recommendation. Staff believes the IPA should avoid purchasing too much capacity in advance of the delivery year because any excess essentially would be sold back to MISO and could be sold back at a significant loss. In Staff's view, the IPA's proposal to limit 1-year and 2-year ahead forward purchases of capacity to 50 percent and 25 percent of Ameren's expected capacity requirements is reasonable and should be approved by the Commission. (Staff Objections at 28)

3. The IPA's Position

In its Objections, Ameren points out that the Plan references soliciting 50% of the forecasted capacity requirements for the second delivery year and 25% of forecasted capacity requirements for the third delivery year, while in other cases the Plan references "at least" 50% of forecasted requirements for the second delivery year and "at least" 25% of forecasted requirements for the third delivery year. The IPA agrees that the use of "at least" creates the potential for ambiguity and that the words "at least" should be removed in Section 1.1 and Section 1.5. (IPA Response at 30)

On page 2 of the Executive Summary, the Plan states that "the IPA recommends purchasing capacity to satisfy a portion of the capacity requirement for Ameren Illinois for the second delivery year and potentially, subject to the consensus of the IPA, ICC Staff and Procurement Monitor, 25% of the forecast requirement for the third delivery year." Those figures appear in Tables 1-2 and 1-3, although the 25% figure is noted as "subject to consensus" (as also in Table 7-14). Ameren believes these usages conflict with the statement in section 7.5.2 that "the Agency is not recommending a capacity procurement for the 2017-2018 period."

The IPA did not intend to affirmatively recommend a capacity procurement for 2017-2018, and seeks to modify the quoted sentence from page 2 to the following:

> Additionally, the IPA recommends purchasing capacity to satisfy a portion of the capacity requirement for Ameren Illinois for the second delivery year. The IPA does not at this time recommend a capacity procurement for Ameren Illinois for the third delivery year; however, to allow for the possibility that market conditions could change sufficiently to make such a procurement desirable, the IPA recommends that the ICC pre-approve the procurement of bilateral contracts covering 25% of the forecast capacity requirement for Ameren Illinois for the third delivery year, subject to the consensus of the IPA, ICC Staff and Procurement Monitor.
> (IPA Response at 30-31)

Ameren also wishes to remove the contingency aspect of the IPA's recommended capacity procurement for the third delivery year. The IPA says Ameren seems to suggest testing the market by holding a procurement event without first taking a contemporaneous look at the market conditions, but also seems to agree that the capacity market in MISO remains uncertain. (IPA Response at 31)

Although the IPA agrees that the benchmark mechanism is a valuable tool for dealing with offer prices that exceed market prices, the IPA is not convinced that it is prudent at this time, in the face of much uncertainty in the MISO capacity market, to commit unconditionally to a procurement event for the third delivery year without first taking a contemporaneous review of the market conditions. The IPA disagrees with Ameren's proposal to use the procurement event to determine whether the market is

willing to offer fair prices and believes its argument should be rejected. (IPA Response at 31)

Ameren makes a secondary recommendation: to include the additional consensus of Ameren and the Procurement Administrator in the determination of whether the contingent procurement event for the third delivery year should be conducted, and to incorporate minor adjustments to the language on page 94 of the Plan. The IPA believes that Ameren's secondary recommendation is a reasonable compromise. Accordingly, the IPA provides specific modifications it proposes to the language on page 94. (IPA Response at 31-32)

4. Commission Analysis and Conclusions

It appears to the Commission that with the exception of one substantive issue, the IPA and Ameren have resolved minor issues intended to clarify the Plan with regard to capacity acquisition for Ameren. The Commission appreciates the efforts of the IPA and Ameren in this regard and the uncontested changes to this portion of the Plan are hereby approved.

Ameren recommends removal of the proposal for consensus associated with the procurement of capacity for the third delivery year. Ameren's rationale is that both the second and third delivery year procurements already have a built-in contingency because confidential benchmarks will be developed, and should capacity offers from suppliers exceed these benchmarks, the rejection of some or all offers could occur. In the event its recommendation is not adopted, Ameren recommends that it and the Procurement Administrator be added to those who must reach consensus on the capacity procurement for the third delivery year.

This proposal is opposed by the IPA because it believes there is too much uncertainty associated with the MISO capacity market at this time. The IPA does not object to Ameren's alternative proposal. While Staff's position on this issue is not entirely clear, it did express concerns about uncertainty in the MISO capacity market and with the possibility of acquiring too much capacity that must be sold back to MISO.

It appears to the Commission that uncertainty in the MISO capacity markets is recognized by all parties and a valid source of concern for Ameren's customers. This is part of the reason the IPA modified its proposed approach to acquiring capacity for Ameren between the draft Plan and the filed Plan.

To some extent, the Commission agrees with Ameren that the confidential benchmarks provide some level of protection to customers. The Commission; however, sees value to providing additional flexibility to the IPA in acquiring capacity for the third delivery year. As a result, the Commission will not accept Ameren's primary proposed change to the Plan with regard to capacity acquisition. The Commission finds that the alternative is reasonable, and hereby adopts, Ameren's alternative proposal. Ameren

and the Procurement Administrator should be added to the group that will need to reach consensus on the acquisition of capacity for the third delivery year.

F. Clean Coal

1. Sargas' Position

Sargas states that it is developing a coal-fired power plant at Mattoon with post-combustion carbon capture for additional economic and environmental benefit. Sargas says the plant has been designed to burn Illinois coal using Sargas' proprietary fluidized bed and CO2 capture technology to generate electricity with 99% SO2 capture, low NOx emissions, and 90%-plus carbon capture. Sargas asserts that captured CO2 will be used beneficially for enhanced oil recovery ("EOR"). Sargas says combustion and emissions reduction are achieved at a high pressure, in the Sargas process, resulting in better efficiency and reduced component size compared to unpressurized systems. According to Sargas, the technology and design implementations result in a modular design approach of increments of approximately 80 MW. Sargas says the initial design of the proposed plant at Mattoon is a single module of approximately 80 MW. (Sargas Objections at 1-2)

Prior to the release of the Draft 2015 Procurement Plan, Sargas indicates its representatives met with the IPA and had discussions concerning the Sargas proposal and the 2015 procurement plan. Sargas says the outcome of these discussions was a proposal by Sargas to include a competitive clean coal procurement in the 2015 Procurement Plan. The IPA has rejected the inclusion of a competitive clean coal procurement in the 2015 Procurement Plan. (Sargas Objections at 3)

Sargas believes that it is crucial to the continued development of clean coal technologies and the coal industry in Illinois for the Commission to follow what it calls the "clear legislative intent" in the enactment of the Clean Coal Portfolio Standard ("CCPS") statute and use its discretionary authority in regulating Illinois' utilities and ARES to require both to purchase power produced by clean coal facilities and procured under a competitive process mandated by the Commission and managed by the IPA as part of the 2015 Procurement Plan. (Sargas Objections at 3)

Sargas asserts that the extensive work it has done on the Mattoon project over the past several years has been undertaken in reliance on the statutory mandates concerning the IPA's statutory obligation to include a clean coal provision in each Procurement Plan. Sargas claims considerable State resources, from the Department of Commerce and Economic Opportunity and Illinois Clean Coal Review Board, have also been expended in this regard. Sargas contends it does not seek special treatment – merely the opportunity to bid competitively in the processes required by the objectives of the legislative plan. Sargas believes the IPA analysis and 2015 Procurement Plan usurps legislative authority by its circumvention of these objectives. (Sargas Objections at 3-4)

Sargas argues that the IPA "clean coal" statutory analysis underlying its refusal to include a clean coal competitive bidding requirement in the Procurement Plan makes clear that the statutory requirement of 25% of Illinois electricity by 2025 to be clean-coal-produced can never be met. In Sargas' view, this analysis entails an inadvertent, but significant, contravention of legislative intent – the 25% can never be met under the rationale for procedures promulgated by the IPA in its Procurement Plan. (Sargas Objections at 4, Reply at 1-2)

Sargas indicates that Section 1-75(d) of the IPA Act includes a CCPS for Illinois. Sargas reports that Section 1-75(d) of the IPA Act also directs that each annual "procurement plan shall include electricity generated using clean coal." (Sargas Objections at 4)

Sargas notes that in December 2012, the Commission approved the annual electricity procurement plan submitted by the IPA and that the 2013 Plan is the first procurement plan to include clean coal. Sargas states that the 2013 Plan indicates that the FutureGen Project is scheduled to go on line in 2017, which is the fifth and final year of the planning horizon considered in the 2013 Plan. Sargas indicates the IPA's 2014 annual procurement plan did not include any clean coal in addition to the FutureGen Project's power purchase agreement and that the current five-year planning horizon includes no new clean coal. (Sargas Objections at 4-5)

Sargas reports that the CCPS also includes a stated legislative objective "that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities." Sargas states that the decision by the Illinois First District Court of Appeals ("First District") affirming the Commission's Final Order that approved the FutureGen Project's power purchase agreement acknowledged the CCPS' 25% clean coal requirement: "The legislature established that by January 1, 2025, '25% of the electricity used in the State shall be generated by cost-effective clean coal facilities.'" (Sargas Objections at 5, citing Commonwealth Edison Co. v. Illinois Commerce Commission, 2014 Ill App (1st) 130544 (July 22, 2014) and Reply at 1-2)

In Sargas' view, the IPA's decision not to include a clean coal project or a clean coal mechanism, such as a competitive clean coal procurement, in the Plan renders it deficient for at least three reasons: (1) the Plan fails to satisfy the requirement in Section 1-75(a) of the IPA Act to include clean coal in each procurement plan; (2) the IPA has not properly prepared to "ramp up" toward a 25% clean coal requirement that is to be met in just over 10 years; and (3) by not including clean coal in this procurement plan the IPA, by its "unelected staff's" action, will effectively prevent any additional clean coal projects from being available to satisfy the 25% legislative directive. (Sargas Objections at 5)

Sargas complains that the Plan is silent about how the IPA intends to account for the 25% by 2025 requirement. Sargas claims the Plan incorrectly refers to the 25% requirement as an "aspirational goal," which it believes is contradicted by both the language in the IPA Act as well as the First District's opinion, which states that the

General Assembly “established” the 25% requirement by 2025. (Sargas Objections at 5)

According to Sargas, under the IPA Act and the PUA, the IPA has both the authority and discretion to adopt its own interim deadlines and percentages as a means to clear up the confusion associated with complying with the CCPS. Sargas says just over ten years away from the January 1, 2025 deadline, the IPA and the Commission have only approved approximately 168 MW of nameplate capacity for clean coal in Illinois, from the FutureGen Project. Sargas says this is less than 1% of Illinois’ annual consumption and far short of the 25% requirement, and given a realistic seven year plant development time, renders the State at risk of violating the 25% requirement, given the effective three year “cushion” remaining. (Sargas Objections at 6)

Sargas states that the First District Appellate Court lent a great deal of deference to the authority of the Commission to interpret, manage and implement statutory provisions pertaining to the CCPS. Sargas says the First District first noted that courts give substantial deference to the Commission's decisions for it is an administrative body with expertise in the area of public utilities, and thus is qualified to interpret highly technical evidence. Sargas also states that the court also emphasized that courts appreciate an agency's experience and expertise in a given area and therefore will give substantial deference to its interpretation of an ambiguous statute it administers and enforces, and that although they are not binding on the courts, an agency's interpretations are an informed source for ascertaining the legislature's intent in enacting the statute. (Sargas Objections at 6)

With reference to these standards, Sargas says the First District found that the Illinois General Assembly granted the IPA and the Commission more authority than usual when it comes to procuring electricity from clean coal facilities stating this legislative intent is reflected in the clean coal portfolio standard which, by its terms, grants the IPA and the Commission more authority in the procurement of electricity from such sources. Sargas indicates the First District also acknowledged the Commission's experience and expertise in this area and gave substantial deference to its interpretation of an ambiguous statute it administers and enforces. (Sargas Objections at 6-7)

Sargas argues that based on the First District’s ruling, the IPA or the Commission could exercise its broad discretion under the CCPS provisions to begin enforcing the ARES’ obligation to source electricity from clean coal facilities in preparation for compliance with the 25% requirement by 2025. Sargas says Section 16-115(d)(5) of the PUA requires each ARES to purchase electricity from clean coal facilities according to the percentage outlined in Section 1-75(d) (or 25% by 2025). Sargas believes the IPA could choose to exercise its discretion under the PUA and IPA Act to establish deadlines in advance of January 1, 2025 for meeting that requirement, just as the IPA has already exercised its discretion by “laddering” purchases as a price hedge. Sargas argues that read together with Section 1-75(a) of the IPA Act – each procurement plan shall include clean coal – both the PUA and IPA Act provisions relating to clean coal

provide the IPA with a mechanism to include clean coal in the current five-year planning window. Sargas believes hosting a competitive procurement would be the most cost-effective mechanism for getting that done. Without a competitive clean coal procurement, or an alternative means for promoting the development of clean coal projects to supply Illinois' electric markets, Sargas contends the Plan is deficient because it includes no mechanism for achieving the statutory directive of 25% clean coal by January 1, 2025. (Sargas Objections at 7)

Sargas reports that in the Plan, the IPA expresses concerns over Sargas' proposal to include a competitive clean coal procurement in the 2015 Plan on the grounds that the IPA may not have the authority to bind both Illinois utilities and ARES to the results of such a procurement. Sargas believes these concerns are not well-founded because the IPA Act and PUA do confer upon the IPA and the Commission the power to conduct a competitive procurement and bind both electric utilities and ARES. (Sargas Objections at 8)

Sargas says generally speaking, the IPA Act's procurement provisions apply to the "eligible retail customers" of Ameren and ComEd: Section 1-75(a) of the IPA Act directs the IPA to develop procurement plans and conduct competitive procurement processes in accordance with the requirements of Section 16-111.5 of the PUA for the eligible retail customers of electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois. In Sargas view, the IPA was designed primarily to procure power on an annual basis for the customers of Ameren and ComEd, not for the customers of the ARES, who compete in a largely unregulated environment. (Sargas Objections at 8)

Sargas states that unlike the FutureGen Project, which was able to proceed under the special Retrofit Provision of the CCPS, a greenfield project like Sargas' proposed clean coal project has no express statutory language to point to as a basis for compelling the ARES to purchase its electricity. Sargas maintains that both the Commission and the First District Court of Appeals found that the Retrofit Provision, because it expressly references ARES, provides a basis for support for requiring both the utilities and ARES to purchase power from a retrofitted clean coal facility. (Sargas Objections at 8)

Sargas asserts that through the various CCPS statutory provisions that the General Assembly intended to grow the use of clean coal by imposing the 25% requirement by 2025, the mechanisms for growing the industry, with the exception of the initial clean coal facility and repowered and retrofitted facilities, are not clearly articulated. Sargas argues that the statutory scheme as a whole confers discretion upon the IPA and the Commission to work toward and achieve the statutory requirement of 25% by 2025. (Sargas Objections at 8-9)

Sargas cites Section 16-115(d)(5) of the PUA which states:

> That the [ARES] applicant will procure renewable energy resources in accordance with Section 16-115D of this Act, and will source electricity from clean coal facilities, as defined in Section 1-10 of the Illinois Power Agency Act, in amounts at least equal to the percentages set forth in subsections (c) and (d) of Section 1-75 of the Illinois Power Agency Act.

Sargas notes that Section also states "for purposes of this Section[:]"

> (iii) the required source of electricity generated by clean coal facilities, other than the initial clean coal facility, shall be limited to the amount of electricity that can be procured or sourced at a price at or below the benchmarks approved by the Commission each year in accordance with item (1) of subsection (c) and items (1) and (5) of subsection (d) of Section 1-75 of the Illinois Power Agency Act[.]

Finally, Sargas cites Section 1-75(d)(5) of the IPA Act which states:

> Pursuant to such procurement planning process, the owners of such [clean coal] facilities may propose to the Agency sourcing agreements with utilities and alternative retail electric suppliers required to comply with subsection (d) of this Section and item (5) of subsection (d) of Section 16-115 of the Public Utilities Act, covering electricity generated by such facilities.

Sargas maintains that the First District found that the IPA and the Commission have the authority to require both Illinois' regulated utilities and ARES to purchase from clean coal facilities, and the IPA reads that decision too narrowly. Sargas says the First District specifically rejected the ARES' argument that the IPA Act and the PUA only apply to the customers of Illinois' electric utilities. Sargas claims the First District found that the IPA Act gives the IPA and the Commission broad authority over the ARES. Sargas asserts that in contrast to the IPA's conservative approach to its authority in the Plan, the First District Court of Appeals found that the IPA and the Commission have more authority in the procurement of electricity from clean coal sources. (Sargas Objections at 9-10)

According to Sargas, Section 16-115(d)(5) of the PUA leaves little doubt that ARES must purchase electricity from clean coal facilities. Sargas asserts the Final Order in Docket No. 12-0544 expressed "incredulity" that the ARES would complain about this requirement. (Sargas Objections at 10)

Sargas indicates that Section 16-115(d)(5)(iii) of the PUA limits the amount of electricity generated by clean coal facilities that the ARES are required to purchase to the percentages in Section 1-75(d) of the IPA Act. Sargas says the only percentage set forth in Section 1-75(d) of the IPA Act, apart from the initial clean coal facility, is 25% by 2025. Sargas states that by the time the Plan goes into effect in 2015, the IPA will have less than 10 years to meet the 25% clean coal requirement. Sargas asserts that the

IPA Act and PUA, as interpreted by the First District Court of Appeals, afford the IPA the mandate to begin ramping up for the January 1, 2025 deadline. In Sargas view, since nothing in the CCPS or PUA limits the IPA from doing so, the IPA's failure to plan for the January 1, 2025 deadline, given the realistic plant development times, makes it likely the 2015 Plan as written will render its efforts to be out of compliance with the IPA Act and the PUA. (Sargas Objections at 11)

Sargas argues to meet its various obligations concerning clean coal power procurement, the IPA not only has the authority to conduct a competitive clean coal procurement, it has an obligation to do so, and thereby comply with the IPA Act's and PUA's CCPS mandated provisions. Sargas contends including a competitive clean coal procurement in the 2015 procurement plan will ensure compliance with those CCPS provisions and is necessary to a realistic possibility of meeting the January 1, 2025 clean coal deadline. (Sargas Objections at 11)

Sargas states that in approving the IPA's recommendation to include a clean coal component in the 2013 procurement plan, the Commission found that the clean coal electricity in that plan helped satisfy its statutory obligations to promote a diverse portfolio of energy supply. Sargas says the Commission also found that including clean coal in the 2013 plan would serve as a reasonable hedge against future carbon risk, particularly as it relates to providing a continued market for the use of Illinois coal, an abundant State resource. Sargas believes conducting a competitive clean coal procurement will further contribute to the State's diverse energy portfolio and will provide an additional hedge against future carbon use restrictions at the federal level. Sargas suggests this would seem to be a particularly prudent approach, given various impending regulatory schemes that will impose clean-coal-like restrictions on all coal-fired electric generation. (Sargas Objections at 11-12)

Sargas proposes that the IPA award a 20-year power purchase agreement for the successful participant(s) in the procurement process. Sargas proposes for those successful bidders (or bidders) to enter into a power purchase agreement(s) with both of Illinois' electric utilities and ARES certified to sell electricity in Illinois under terms developed by the Commission. (Sargas Objections at 12)

Sargas says the IPA agrees that benefits such as job creation, technology advancement and industry advancement are both real and meaningful, and would add that new facilities can also contribute to the least total cost over time, taking into account the benefits of price stability through a more robust and diverse supply portfolio. Sargas states that despite the argument made to the contrary by the IPA in its response, any movement toward reaching the goal contained in the CCPS, no matter how small, is movement in the right direction and brings the State closer to the clean coal goal. (Sargas Reply at 2)

Sargas indicates it is well aware of the requirement for meeting benchmark standards as contained in the CCPS and as they pertain to clean coal facilities. As such, Sargas understands that any new clean coal facility will have to produce power at

a price below the yet-to-be developed benchmark for clean-coal-produced power. Sargas believes that a clean coal power procurement process can identify a provider of power that is able to meet any yet-to-be developed benchmark for the price of clean coal. Based upon the preliminary numbers for its cost of power production and the benchmark already developed by the IPA for the FutureGen project, Sargas is confident that its Mattoon facility will produce power below any benchmark set by the IPA. Sargas says much like the FutureGen project, Sargas believes that the benchmark for this clean coal procurement will ultimately be developed after any such competitive procurement process for new clean coal power. (Sargas Reply at 2-3)

Sargas also indicates it is aware of the rate caps contained in the CCPS and understands that they constrain any new clean coal power produced for the Illinois market. Based on the preliminary numbers developed by Sargas, it believes it, and perhaps others, can produce power within the constraint of the current rate caps contained in the CCPS. Sargas complains that a great part of the benchmark and rate cap arguments are based upon hypothetical cases, undeveloped benchmarks, and costs unknown to the individuals making the arguments. Sargas claims the undisputed fact is that the CCPS requires any clean coal power be subject to the benchmarks as established by the IPA and the rate caps as set by the Illinois legislature. Sargas says all power procured by the IPA under a competitive process, without regard to the source, would need to meet the benchmark and the price would be constrained by the rate caps as currently contained by the CCPS. Sargas notes that the legislature put in place an automatic review of the rate caps. (Sargas Reply at 3)

Sargas states that pursuant Section 1-75(d)(2)(E) of the IPA Act to prior to June 30, 2015 the Commission must review the rate caps and report to the General Assembly whether the rate caps contained in the CCPS unduly constrain the amount of electricity generated by cost-effective clean coal facilities. With regard to the benchmarks and rate caps, Sargas says what the opponents are asking is that one of the parties available to bid in an open procurement process demonstrates that its bid will comply with yet to be determined benchmarks and rate caps based on yet to be built facility. Sargas contends the current statutory requirements already have those safeguards in place to protect the consumers from overpriced clean coal power. (Sargas Reply at 4)

Sargas asserts that in its ruling in Docket No. 12-0544 the Commission provided some opinion relevant to the arguments currently being made against inclusion of a competitive clean coal power procurement in this year's plan. Sargas says the Commission recognized the legislature's commitment to the development of clean coal technology, saying "It is the policy of the State of Illinois, as expressed by the General Assembly, to encourage generation of electricity from clean coal generating stations. That policy is expressed in the specific provisions of the IPA Act and the PUA, which direct the IPA to include electricity generated by clean coal facilities in its procurement plans, require Illinois utilities and ARES to source electricity from clean coal facilities, and establish a specific process and standard of consideration for agreements like the

sourcing agreement for the FutureGen project." (Sargas Reply at 4, citing Docket No. 12-0544, Order at 230)

Sargas also says the Commission previously recognized that Section 1-5 of the IPA Act includes a finding by the General Assembly that the State should encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to demonstrate the viability of coal in a carbon constrained economy. (Sargas Reply at 4-5)

In regard to the IPA's argument that each plan need not include clean coal, Sargas says the Commission has stated that Section 1-75(a) of the IPA Act requires the IPA to develop annual procurement plans, and Section 1-75(d) of the IPA Act includes an express requirement that annual procurement plans include electricity generated by clean coal facilities. Sargas notes the first sentence of Section 1-75(d) of the IPA Act, titled "Clean Coal Portfolio Standard," includes a mandate that annual procurement plans include electricity generated by clean coal facilities: "The procurement plans shall include electricity generated using clean coal." (Sargas Reply at 5)

2. ICA's Position

The ICA objects to the exclusion of new clean coal power procurement in the proposed plan and encourages the Commission to include the opportunity for new clean coal technology projects in the Final 2015 Power Procurement Plan. The ICA asserts that the Illinois coal industry and its employment economics will be negatively affected by the announced retirements of existing coal-fired generating facilities, and recently promulgated (and expected) federal emissions guidelines are expected to have a significant negative effect on any new coal projects that lack clean coal features. (ICA Objections at 1)

The ICA contends the importance of clean coal was recognized and acted upon by the Illinois legislature in its creation of the clean coal features and procurement procedures via the IPA Act and related legislation. The ICA says the IPA's recently proposed 2015 Procurement Plan ignores clean coal entirely, relying on a statutory interpretation that makes impossible the achievement of the legislative purpose of having 25% clean coal power in Illinois by 2025. The ICA claims that by the interpretation submitted, no new projects will ever be defined as clean coal in order to participate in competitive procurement to be conducted by the IPA. (ICA Objections at 1-2)

The ICA argues that permitting clean coal into the Illinois IPA procurement portfolio will make Illinois a leader and case example of the existence and benefits of genuine clean coal technology. The ICA claims this fact will stimulate market growth for Illinois coal in the near future, as nearby states undertake to install new clean coal facilities - with corresponding retention and creation of jobs in the coal industry. (ICA Objections at 2)

The ICA requests that the Commission modify the proposed Power Procurement Plan to include the opportunity for development of clean coal technology. (ICA Objections at 2)

3. IBEW's and Plumbers & Steamfitters Position

The Commission notes that IBEW and the Plumbers & Steamfitters filed identical Objections, which will not be repeated.

IBEW objects to the fact that Plan excludes new clean coal power procurement and encourages the Commission to include the opportunity for new clean coal technology projects in the Final approved Plan. IBEW asserts that new clean coal technology power plants will not only create new construction jobs but insure the continued viability of the coal mining industry within Illinois. (IBEW Objections at 1)

IBEW asserts that with the ever increasing regulation of power production, especially coal fired power production, the State and the Nation need the continued development of clean coal technologies in order to provide a cost effective and balanced approach to power production. IBEW claims through the Clean Coal Portfolio Standard, the Illinois legislature intended to provide for advancement of clean coal technology and the most efficient way to promote that advancement is to include the opportunity for those technologies in the 2015 Power Procurement Plan. (IBEW Objections at 1)

IBEW states that the clean coal technologies currently under development not only offer the opportunity for job creation and technological advancement but also the creation of entirely new industries. IBEW says from CO2 sequestration to enhanced oil recovery, developing clean coal technology is opening the door to new advancements in other areas of the economy. The IBEW also says the use of CO2 for Enhanced Oil Recovery, currently used successfully in other parts of the country, has the ability to unlock oil currently unreachable by the method now employed in the oil fields of Southern Illinois. The IBEW believes the availability of CO2 from clean coal power plants could provide an entirely new industry for parts of Illinois. (IBEW Objections at 2)

4. Staff's Position

While Staff finds the overall legal analysis set forth in the IPA Plan regarding Clean Coal to be well reasoned, consistent with the PUA and the IPA Act and has no basis to take issue with the facts alleged concerning Sargas in the IPA Plan, Staff does propose: (a) edits clarifying what is not provided for in the IPA Act and (b) two non-substantive edits. (Staff Objections at 29-30)

Staff reports that in Section 7.7.2, the Plan states that "The Agency does not have a mechanism for considering sourcing agreements from a standard, non-delineated "clean coal facility" …" Based upon a reading of the IPA Act, Staff believes it is more accurate to state that "The IPA Act does not direct the Agency to consider

sourcing agreements from a standard, non-delineated "clean coal facility." (Staff Objections at 30)

Staff notes that the Plan states that "Section 1-75(d)(5) of the IPA Act provides an express mechanism for the IPA's consideration of sourcing agreements between alternative retail electric suppliers and owners of retrofitted clean coal facilities. But for a non-retrofitted, greenfield "clean coal facility," such as Sargas, the IPA Act contains no such mechanism for considering sourcing agreements involving ARES." Based upon a reading of the IPA Act, Staff believes it is more accurate to state that "Section 1-75(d)(5) of the IPA Act provides an express mechanism for the IPA's consideration of sourcing agreements between, utilities, alternative retail electric suppliers and owners of retrofitted clean coal facilities. But for a non-retrofitted, greenfield "clean coal facility," such as Sargas, the IPA Act contains no such mechanism for considering sourcing agreements." (Staff Objections at 30)

Staff notes that several parties cite to job creation and clean coal market growth as reasons for including a clean coal procurement in the Plan. Staff argues the PUA is clear that the standard for determining whether a Plan should be approved by the Commission is not whether the Plan will create jobs or provide for market growth, but rather whether the Plan "[ ] 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." Staff claims that nowhere do those parties address that standard. For this reason, Staff believes the parties' suggested change to the Plan should be rejected. (Staff Response at 13)

Sargas wants the Plan to include a specific procurement of 100 MW of electricity generated by clean coal facilities that capture and sequester CO2 emissions. Sargas specifically wants the Plan to include a 20-year power purchase agreement for successful bidders in the procurement process. Sargas also wants the Plan to provide that both Illinois electric utilities and ARES certified to sell electricity in Illinois would be required to enter into power purchase agreements with the successful clean coal bidders. Sargas argues in support for its proposal that the Commission and the IPA have broad discretion to include a clean coal procurement in the Plan. Staff complains that nowhere in Sargas' objections does it discuss the fact that pursuant to the PUA, ARES are only required to source electricity from clean coal facilities other than the initial clean coal facility in an amount that can be procured or sourced at price at or below benchmarks approved each year by the Commission "in accordance with item (1) of subsection (c) and items (1) and (5) of subsection (d) of Section 1-75 of the Illinois Power Agency Act[.]" (Staff Response at 14)

Staff also complains that nowhere in its objections, does Sargas address the fact that utilities are not required to purchase electricity from clean coal facilities other than the initial clean coal facility, at prices that exceed a Commission-approved cost-based benchmark. Staff says to date the Commission has not approved cost-based benchmarks for a clean coal facility, other than for a retrofit clean coal facility. Absent the Commission approval of a cost-based benchmark and an analysis of whether the

purchase of more clean coal would meet the cost-effective requirements of the IPA Act, Staff contends it would be premature for there to be a clean coal procurement included in the Plan other than for the retrofit clean coal facility, FutureGen. (Staff Response at 14)

Staff maintains that unlike for the initial clean coal facility and for a retrofit clean coal facility, the IPA Act does not direct the IPA to consider sourcing agreements for standard non-delineated clean coal facilities. Staff says Sargas' proposal has Commission approval of a sourcing agreement as a critical element of its proposal. Staff notes Sargas cites to the recent Appellate court case to support its position, but Staff claims the facts in that case are far different than what Sargas is proposing here. Staff says that case involved FutureGen, a retrofit clean coal facility. Staff says retrofits have a specific statutory section dealing with them (Section 1-75(d)(5) of the IPA Act). Staff indicates Sargas' planned facility and other standard non-delineated clean coal facilities are treated differently than retrofits and the initial clean coal facility under the IPA Act and PUA. Staff says those non-delineated clean coal facilities fall under Section 1-75(d)(1) of the IPA Act. Staff contends that under that section, there is no express authority given by the legislature to the IPA and Commission to consider sourcing agreements for standard non-delineated clean coal facilities, like Sargas. Staff maintains that only the benchmark for such facilities is addressed in Section 1-75(d)(1). Staff insists there is no authority to approve a sourcing agreement as Sargas proposes, similar to the manner in which one was approved for FutureGen. In Staff's view, this failure by Sargas to adequately address the lack of authority for the IPA and Commission to consider sourcing agreements with facilities like Sargas is critical and provides yet another reason for the Commission to reject Sargas' proposal. (Staff Response at 15-16)

Staff also identifies what it describes as non-substantive edits and provides specific changes intended to improve the Plan. (Staff Objections at 30-34)

5. The IPA's Position

According to the IPA Sargas claims that the IPA's plan fails to comply with the IPA Act's directive to include electricity generated by clean coal and fails to meet the IPA Act's "25% by 2025" clean coal sourcing requirement. The IPA says Sargas argues that the IPA has the authority to bind ARES to a power purchase agreement from a "clean coal facility." The IPA also says Sargas argues the IPA should conduct a clean coal procurement as a hedging strategy. (IPA Response at 32)

Having reviewed Sargas's objections, the IPA stands by the analysis contained in the Plan. In the abstract, the IPA believes it may have authority conduct a competitive clean coal procurement pursuant to Section 1-75(d)(1) of the IPA Act, and a facility such as Sargas may make a valuable contribution to a more diverse supply portfolio. The IPA says it appreciates the comments put forward by IBEW, the International Brotherhood of Boilermakers Local Lodge 363, Plumbers & Steamfitters Local 149, and the Illinois Coal Association touting the job creation, technology advancement, and

industry creation benefits that a competitive clean coal procurement may bring to Illinois. The IPA agrees that such benefits are both real and meaningful, and would add that new facilities can also contribute to the "least total cost over time, taking into account the benefits of price stability" through a more robust and diverse supply portfolio. (IPA Response at 32)

The IPA does not agree that it has authority to bind ARES to a power purchase agreement through a competitive clean coal procurement conducted under Section 1-75(d)(1) of the IPA Act. The IPA "develop[s] procurement plans and conduct[s] competitive procurement processes . . . for the eligible retail customers of electric utilities." The IPA asserts customers who are not "eligible retail customers," customers of retail electric suppliers, among others, "shall not be included in the procurement plan load requirements." In the IPA's view, no matter how compelling any policy arguments may be, it is axiomatic that the IPA does not procure supply for retail suppliers absent express statutory authority to do so. (IPA Response at 33)

The IPA says the Illinois First District Court of Appeals says such authority does exist with respect to 1-75(d)(5) of the IPA Act, applying to "retrofitting or repowering clean coal facilities." According to the IPA, the Appellate Court held that "[i]f the [IPA] can consider such agreements, it is reasonable to presume that the IPA can compel ARES to enter into sourcing agreements with such facilities as part of the procurement planning process if doing so furthers statutory goals." (IPA Response at 33)

The IPA states that the Sargas project is not a "retrofit clean coal facility," express authority to bind ARES does not exist for such a project. While the IPA finds Sargas' arguments creative, it argues this indirect approach reads the far more direct requirement that the IPA conduct its procurement process for "eligible retail customers" out of the law and renders meaningless Section 1-75(d)(5)'s expressly articulated allowance for the consideration of "sourcing agreements with . . . alternative retail electric suppliers." The IPA claims the Appellate Court relied heavily on this specific statutory exception to the general rule, reading the law to render this very language superfluous is both inconsistent with governing jurisprudence and with a fair reading of the IPA Act. (IPA Response at 33-34)

Absent authority to bind ARES to the output of a "clean coal facility," the IPA says it cannot recommend including a competitive clean coal procurement as part of its 2015 Plan. The IPA states any such procurement would be subject to the statutory 2.015% rate impact cap – a limitation which would be borne exclusively by eligible retail customers, resulting in only a small portion of the winning bidder's output being covered (with those contracts subject to potential curtailment based on load migration to retail suppliers). The IPA recommends that the proposal for a competitive clean coal procurement be denied. (IPA Response at 34)

Sargas also argues that absent a competitive clean coal procurement, the IPA has not properly prepared to ramp up toward a 25% clean coal requirement that is to be met in just over 10 years. The IPA claims sourcing agreements with FutureGen 2.0 are

forecast to use up approximately two-thirds of the budget available under the clean coal portfolio standard's rate impact cap, while providing just 0.9% of the state's electric supply. The IPA states with the inclusion of Sargas, even assuming that ARES could be bound to purchase its output, this number would climb only to 1.4%, and no additional clean coal projects could ever be authorized under Section 1-75(d)'s rate impact cap. The IPA says it would be left 23.6% short of a 25% target, with Sargas having taken up any remaining funding available. (IPA Response at 34-35)

Sargas also argues that if a competitive clean coal procurement is not included in the IPA's Plan, the IPA will have failed to satisfy 1-75(a)'s requirement to include clean coal in each procurement plan. The IPA states that the 2015 Plan considers a 5-year planning horizon that begins with the 2015-2016 delivery year and lasts through the 2019-2020. The IPA maintains it has already authorized sourcing agreements with FutureGen 2.0, a retrofit clean coal facility scheduled to come online in 2017. The IPA insists FutureGen 2.0 constitutes "clean coal," and it is included in the Plan. The IPA asserts a competitive clean coal procurement seeking power purchase agreements with facilities such as Sargas, which seeks to begin providing energy in 2019, would not bring the IPA into closer compliance with a requirement to include clean coal in a plan developed for this five-year planning horizon. (IPA Response at 35)

The IPA notes Staff recommends minor clarifying and non-substantive edits to the discussion in Section 7.7.2 of the Plan. The IPA supports these changes and recommends their adoption. (IPA Response at 35)

The IPA generally agrees with the Responses field by ComEd, Ameren, Staff, RESA, and ICEA with respect to Sargas' competitive clean coal procurement Objection. In particular, the IPA supports ICEA's request for an express determination that the 2015 Plan features the inclusion of "electricity generated using clean coal" through existing contracts with the FutureGen 2.0 retrofit "clean coal" facility, and agrees with multiple parties' statements that any clean coal facility authorized under Section 1-75(d)(1) of the IPA Act, such as Sargas, would be subject to a cost-based benchmark. (IPA Reply at 14-15)

On exceptions, Sargas seeks the inclusion of a competitive clean coal procurement in part because the current 5-year procurement planning horizon contains no clean coal project or procurement. The IPA maintains this is incorrect, as the IPA's current procurement planning horizon features executed sourcing agreements with a retrofit clean coal facility as defined by Section 1-75(d)(5) of the IPA Act. The IPA says delivery of electricity under those agreements is scheduled to commence in 2017. The IPA suggests that to avoid such confusion, the Commission should consider an express statement that the IPA's 2015 Procurement Plan includes "electricity generated using clean coal" by virtue of existing contracts with the FutureGen 2.0 facility. (IPA RBOE at 14-15)

The IPA claims Sargas presents no new arguments on exceptions for its competitive clean coal procurement proposal, and its proposed language fails to draw

any distinction between procurement on behalf of eligible retail customers and procurement binding alternative suppliers, which is prohibited absent express statutory authority to the contrary. The IPA also says its statement that the Proposed Order would end the possibility of any future projects being considered under the clean coal portfolio statute as they are currently written is also incorrect, as projects meeting other criteria may still proceed under provisions other than Section 1-75(d)(1). (IPA RBOE at 15)

6. Ameren's Position

Ameren agrees with the IPA and Staff that procurement from Sargas should not be included in the Plan. Ameren says the IPA puts forth a legal basis for not including a procurement of Sargas in the Plan, and Staff provides additional clarity in its Objection that the IPA Act contains no mechanism to consider sourcing agreements from non-retrofitted greenfield clean coal plants such as Sargas. (Ameren Response at 1)

Aside from the legal argument, Ameren indicates it has executed a sourcing agreement with FutureGen where current projected costs are expected to consume the majority of the rate cap associated with the Clean Coal Portfolio Standard. Ameren says this sourcing agreement includes a Staff review of costs throughout the term of the agreement followed by an annual order by the Commission. Ameren states that if actual costs associated with FutureGen exceed current projected costs, any "balance" under the rate cap would be reduced. Ameren also says under a scenario where actual costs associated with FutureGen cause the rate cap to be exceeded, costs under the sourcing agreement would be adjusted downward to a level where the rate cap is no longer exceeded. Ameren emphasizes that actual FutureGen costs remain uncertain and therefore a decision to procure additional clean coal at this time could result in stranded costs since customers (or utilities) would not be responsible for costs in excess of the rate cap. In Ameren's view, the decision by the IPA to omit Sargas from the Plan is appropriate because the proposal lacks a legal basis and the future rate cap balance, if any, remains uncertain. (Ameren Response at 1)

7. ComEd's Position

According to ComEd, the entirety of Sargas' proposal rests on only a couple of phrases "cherry-picked" from the Clean Coal Portfolio Standard. ComEd says these include a purported "requirement" that 25% of Illinois electricity by 2025 be "clean-coal-produced" and the claim that "each annual 'procurement plan shall include electricity generated using clean coal.'" ComEd argues that when read in context, these phrases do not support the sort of procurement suggested by Sargas. (ComEd Response at 15)

ComEd states that the introductory paragraph to Section 1-75(d) of the IPA Act introduces the CCPS, expresses the goals of the General Assembly in enacting this law, and indicates how the legislature generally intended the goals to be accomplished. Important to ComEd is that this paragraph indicates the utilities' execution of sourcing agreements with the initial clean coal facility would feature prominently in the

achievement of the goal. ComEd says since the CCPS became law in 2009 no clean coal facility has ever been proposed that would fit the statutory requirements applicable to qualify as the initial clean coal facility. ComEd also says Sargas admits that its facility would not be the "initial clean coal facility." ComEd argues that because this condition precedent (or "trigger") has not occurred, to date there has been no requirement that utilities' procurement plans include any electricity generated using clean coal from the initial clean coal facility. (ComEd Response at 16)

ComEd says while nearly all of the CCPS is devoted to defining and approving the initial clean coal facility and the development and execution of sourcing agreements between the utilities and this facility, the CCPS makes allowance for sourcing agreements with one other type of clean coal facility. ComEd says paragraph (5) of the CCPS requires the IPA and the Commission to consider the sourcing of electricity from certain retrofitted coal facilities previously owned by Illinois utilities. (ComEd Response at 17)

ComEd states that unlike the initial clean coal facility provisions, this provision has been invoked. In the course of approving the 2013 IPA Plan, ComEd notes the Commission considered a proposal by FutureGen 2.0 under paragraph (5). ComEd says because FutureGen 2.0 qualified as a retrofitted coal-fired power plant previously owned by an Illinois utility that will be converted into a clean coal facility, the Commission exercised its authority under paragraph (5) to consider sourcing agreements with such a facility and ultimately approved the sourcing of power from FutureGen 2.0 by Illinois utilities and alternative retail electric suppliers. ComEd indicates Sargas does not contend that its proposed clean coal facility qualifies as a retrofitted facility under paragraph (5). (ComEd Response at 17-18)

ComEd argues that because Sargas does not qualify as either the initial clean coal facility or a retrofitted clean coal facility, Sargas' proposal cannot be considered or approved under the CCPS. ComEd asserts Sargas' attempts to inflate aspirational language into hard requirements in conflict with the CCPS are unavailing. ComEd maintains the legislature's goal to source 25% of the State's electricity from clean coal facilities by 2025 does not trump the intricate and explicit CCPS statutory framework or override the exclusive means by which electricity generated by clean coal facilities can be sourced (i.e., from the initial clean coal facility or a retrofitted facility previously owned by an Illinois utility). (ComEd Response at 18)

ComEd finds unavailing Sargas' claim that the introductory sentence of paragraph (1) – "[t]he procurement plans shall include electricity generated using clean coal" – should be read in isolation as an absolute mandate and without regard to the larger context and statute. According to ComEd, the very next sentence explains the contemplated process for how clean coal would be included in the procurement plans – each utility shall enter into one or more sourcing agreements with the initial clean coal facility. ComEd says subparagraphs (2) through (4) continue to provide, over the course of several pages, the details regarding how utilities and alternative retail electric suppliers will procure power from the initial clean coal facility, how the sourcing

agreements will be structured, and the requirements the initial clean coal facility must satisfy. ComEd asserts the CCPS only departs from its focus on the initial clean coal facility when it makes provision for a retrofit facility – the only other means for including electricity from a clean coal facility in procurement plans. ComEd argues that contrary to Sargas' claims, the procurement plans already include electricity from clean coal facilities. ComEd believes no requirement exists that every procurement plan must include new, incremental electricity sourced from clean coal facilities and neither the budgets nor clean coal facilities are of sufficient size or number to accommodate such an interpretation. (ComEd Response at 18-19)

In ComEd's view, Sargas should defer to the IPA's interpretation of its statute. ComEd says Sargas quotes extensively from a recent Appellate Court decision, which summarizes the well-established principles that "courts appreciate an agency's experience and expertise in a given area and therefore will give substantial deference to its interpretation of an ambiguous statute it administers and enforces." ComEd states "although they are 'not binding on the courts, an agency's interpretations are an informed source for ascertaining the legislature's intent in enacting the statute.'" ComEd asserts consistent with these principles, the Plan's analysis and conclusions regarding Sargas should prevail. (ComEd Response at 19-20)

ComEd states that Sargas devotes no more than two pages of its Objections to describing its proposed clean coal facility. ComEd claims Sargas' proposal contains no detail regarding costs, customer rate impacts or what the sourcing agreements would entail. ComEd says no cost detail is presented, much less the statutorily required showing that this power represents the lowest cost over time. ComEd finds this concerning given that Sargas would apparently be the only participant in the "competitive" procurement process it proposes. ComEd suggests that as the sole bidder, it appears that Sargas would require customers to pay for this electricity no matter how expensive it is to generate. ComEd asserts that while the power cost would be subject to the overall rate impact caps set forth in the CCPS, to the extent margin is left after accounting for FutureGen 2.0, even this is insufficient to protect customers. ComEd says simply because the cost of electricity cannot exceed an overall cap does not mean that, on a price per kilowatt-hour basis, the cost is reasonable or the overall project is cost effective. ComEd contends that because Sargas proposes that its power be procured through a procurement process and the IPA is limited to procuring for only the utilities' eligible retail customers, it is unclear if that means that only this small subset of customers who take fixed-priced bundled service will be saddled with the costs to source Sargas' electricity. In ComEd's view, such a result would be unfair to ComEd supply customers, is at odds with legislative intent, and should be rejected by the Commission. (ComEd Response at 20-21)

8. ICEA's Position

In ICEA's view, the Plan provided several well-reasoned arguments in favor of its position to reject a competitive clean coal procurement, all of which ICEA support. ICEA claims further statutory analysis supports the Plan's conclusions, which were in part

based on the differences in authority between Sections 1-75(d)(1) and (d)(5) of the IPA Act. (ICEA Response at 4-5)

ICEA says no party appears to contest the Plan's conclusion that Sargas's proposed procurement would not be restricted to facilities that qualify under 1-75(d)(5) of the IPA Act. ICEA believes the Plan correctly concluded that Section 1-75(d)(5) of the IPA Act is inapplicable. (ICEA Response at 6)

ICEA notes the Plan's conclusion that any procurement of clean coal resources must be required or authorized by Section 1-75(d)(1) of the IPA Act. Section 1-75(d)(1) states that: "The procurement plans shall include electricity generated using clean coal;" however, ICEA believes that this has been accomplished by the inclusion of FutureGen as supply from clean coal already under contract. ICEA asserts Section 1-75(d)(1) of the IPA Act does not require a procurement in any given year, it merely requires inclusion of "electricity generated using clean coal." ICEA recommends that the Commission explicitly find that the Plan has met this statutory burden by including FutureGen 2.0 that is already under contract pursuant to sourcing agreements with utilities. (ICEA Response at 6)

Even to the extent that the Commission does not believe that Section 1-75(d)(1) is satisfied by inclusion of FutureGen, ICEA argues that there is no authority to bind RES with any sourcing agreement procured under the mandates of Section 1-75(d)(1). ICEA states that unlike Section 1-75(d)(5), Section 1-75(d)(1) does not mention ARES or RES. Although ICEA does not agree with the Illinois Appellate Court's decision regarding the authority of the Commission to bind RES with regard to Section 1-75(d)(5), the sourcing agreement language that the Appellate Court relied on in 1-75(d)(5) is not present with regard to ARES in Section 1-75(d)(1). (ICEA Response at 6-7)

Although ICEA is continuing to litigate the question of whether RES may be bound by sourcing agreements under Section 1-75(d)(5) of the IPA Act, ICEA agrees with Staff that there is no authority to bind RES under Section 1-75(d)(1) of the IPA Act. (ICEA Response at 7)

ICEA states that in its Objections, Sargas recommends a clean coal procurement, presumably for facilities similar to Sargas's planned facility in Coles County. In ICEA's view, Sargas's arguments are insufficient to disturb the Plan's decision. ICEA argues that contrary to Sargas's contention that it "does not seek special treatment," it does in fact seek special treatment for clean coal procurement that the Plan demonstrated was imprudent. Sargas cites Section 1-75(d)(1) for the proposition that the Plan "shall include electricity generated using clean coal." ICEA asserts that FutureGen 2.0 satisfies that requirement. ICEA contends that Sargas misinterprets the Appellate Court opinion because the Appellate Court decision relied on the mention of IPA planning authority regarding ARES in Section 1-75(d)(5) of the IPA Act. (ICEA Response at 7-8)

ICEA claims that acknowledging that there is no mandate to procure clean coal, Sargas makes the argument that the IPA and the Commission should "exercise discretion" to approve a clean coal procurement. ICEA says the Plan articulates reasons why such a procurement would be imprudent. According to ICEA, the Plan concludes that a procurement would be imprudent; as a result, the Commission should not exercise its discretion to authorize any imprudent clean coal procurements. (ICEA Response at 8)

ICEA says Sargas attempts to counter the Plan's prudence argument by arguing that the Plan "has not properly prepared to 'ramp up' toward a 25% clean coal requirement that is to be met in just over 10 years." ICEA claims Sargas's argument does not correctly capture clean coal procurement requirements. ICEA states that Section 1-75(d)(1) of the IPA Act does not set a target for procurements from "clean coal facilities" but "cost-effective clean coal facilities" ICEA says "cost-effective" is defined in part as: "the expenditures pursuant to such sourcing agreements do not cause the limit stated in paragraph (2) of this subsection (d) to be exceeded and do not exceed cost-based benchmarks." ICEA agrees with the Plan that FutureGen is anticipated to take up 65% of the statutory cap. With only 35% of the cap remaining, ICEA expresses concern that even a single project might put the IPA at or over the cost cap for the duration of the FutureGen sourcing agreement. ICEA argues there is no need for a "ramp-up" with so little of the statutory budget cap remaining. (ICEA Response at 8-9)

ICEA says the standard for approval of the Plan is whether the Plan: "will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." ICEA says nowhere to be found in that standard is promoting clean coal, or approving a project because it creates jobs as IBEW suggests. (ICEA Response at 9)

ICEA states that it, the IPA, Staff, and ComEd make similar and complimentary arguments regarding the requirements of and authority under Section 1-75(d)(1) of the IPA Act. ICEA says neither Sargas nor any other party filed a Response addressing the statutory issues raised by ICEA and others in Objections. ICEA recommends that the Commission preserve the Plan's rejection of a new clean coal procurement. (ICEA Reply at 17-18)

ICEA maintains that RES cannot be bound by sourcing agreements authorized by Section 1-75(d)(1) of the IPA Act. ICEA recommends that the Commission supplement the Proposed Order to reflect the additional bases for rejecting Sargas' proposed procurement raised by Staff, the IPA, ICEA, RESA, ComEd, and Ameren. (ICEA RBOE at 7)

9. RESA's Position

RESA says in its Objections, Sargas basically makes the same arguments that it made in its Comments on the 2015 Draft Plan. RESA says those arguments have

already been considered and rejected by the IPA. RESA does not believe that there is anything of merit in the Objections that justifies a different result. RESA agrees with the IPA that Sargas' position would require a change in the IPA Act. RESA believes the Commission should accept the IPA's exclusion of the clean coal procurement contemplated by Sargas. (RESA Response at 6)

The IPA basically relies on the opinion in Commonwealth Edison Co. v. Illinois Commerce Commission, 2014 IL App (1st) 130544, July 22, 2014, to state that while the Commission has the authority to require ARES to enter into sourcing agreements with a retrofitted clean coal facility such as FutureGen, the Commission does not have the authority to require ARES to enter into sourcing agreements with other types of clean coal facilities, such as that contemplated by Sargas. RESA disagrees with the IPA's position and the Appellate Court's acceptance of that opinion and notes that the Appellate Court's opinion is the subject of a motion for leave to appeal to the Illinois Supreme Court. RESA says the IPA relies on a decision which is pending further appeal for support for Commission authority to impose sourcing agreement burdens on ARES for retrofitted clean coal plants, which RESA believes is premature. In RESA's opinion, the IPA and the Commission do not have the authority to require ARES to enter into sourcing agreements, other than with the initial clean coal facility, which neither FutureGen nor Sargas is. (RESA Reply at 8-9)

Staff also supports the exclusion of the clean coal procurement proposed by Sargas from the 2015 Plan. While RESA agrees with the Staff that that procurement should be excluded, RESA disagrees with the Staff's position, similar to that of the IPA, that the IPA and the Commission can require ARES to enter into a sourcing agreement with a retrofitted clean coal facility. (RESA Reply at 9)

AIC takes the position, and RESA agrees, that the decision of the IPA to omit the clean coal procurement proposed from the 2015 Plan is appropriate because the legal basis is lacking and the future rate cap balance, if any, remains uncertain. ComEd takes the position, and RESA agrees, that the IPA Act neither requires nor authorizes the clean coal procurement requirement of ARES as proposed by Sargas. (RESA Reply at 9)

ICEA also takes the position that the IPA correctly decided not to include the clean coal procurement proposed by Sargas in the 2015 Plan. ICEA also states the position, supported by RESA that it does not agree with the Illinois Appellate Court's decision which found that the Commission had the authority to require ARES to enter into sourcing agreements with retrofitted clean coal facilities such as FutureGen. (RESA Reply at 9)

RESA notes that Sargas' Brief on Exceptions proposes to revise the Proposed Order to reverse its position and order a competitive clean coal procurement as contemplated by Sargas. RESA claims that Sargas does not in any way refute the analysis of the Proposed Order that supported its conclusion to exclude the proposal. (RESA RBOE at 4-5)

10. IIEC's Position

IIEC supports the recommendations of the IPA, Staff, Ameren, ComEd, and ICEA to reject the Sargas request.

IIEC does not believe there is statutory authority for the Clean Coal Power Procurement as proposed by Sargas. IIEC says Sargas fails to identify any statutory language which specifically grants the IPA or the Commission authority power to compel utilities or ARES to enter into sourcing agreements with the Clean Coal Facilities of the Sargas kind. (IIEC RBOE at 1-2)

IIEC states that Sargas fails to explain why the lack of detail in its proposal is not a barrier to the evaluation of a sourcing agreement for the kind of facility proposed by Sargas. (IIEC RBOE at 2)

11. Commission Analysis and Conclusions

Sargas, ICA, and IBEW and Plumbers & Steamfitters urge the Commission to include a competitive clean coal procurement in the Plan. Sargas argues that the Commission and IPA have the discretion to include in procurement plans the type of facility it is proposing. This proposal is opposed by the IPA, Staff, ComEd, Ameren, ICEA, RESA, and IIEC. Among other things, ComEd, Ameren, ICEA, and RESA claim that such a procurement is not authorized by the IPA Act or the PUA.

Assuming for the moment that the proposed Sargas facility qualified as a clean coal facility under Illinois law, there is essentially no discussion of how the IPA or the Commission would develop or evaluate a sourcing agreement with such a clean coal facility. This is in stark contrast to the detailed explanation of the requirements for, the approval process, and associated sourcing agreements associated with the initial clan coal facility and the re-powered and retrofitted coal power plants previously owned by Illinois utilities which qualify as clean coal facilities. The Commission finds this lack of detail a barrier to any evaluation.

The Commission has carefully reviewed the PUA and the IPA Act and there is extensive discussion of the initial clean coal facility and re-powered and retrofitted coal power plants previously owned by Illinois utilities which qualify as clean coal facilities. While there are few reference to the generic term clean coal facility; there is no specific reference to, or discussion of, what Sargas describes as a greenfield facility. The Commission acknowledges that neither the PUA nor the IPA Act explicitly prohibits consideration of clean coal facilities other than the initial clean coal facility and re-powered and retrofitted coal power plants previously owned by Illinois utilities which qualify as clean coal facilities. Based upon its review of the law and the information provided, it is not clear to the Commission that the facility proposed by Sargas qualifies as a clean coal facility under Illinois law.

It is true that Illinois courts often defer to the expertise of administrative agencies. In this case, the Commission is not convinced that a proposal of the type presented by Sargas was contemplated by the Illinois General Assembly or is in the public interest. As a result, the Commission will not include a competitive clean coal procurement in the pending Procurement Plan.

G. Demand Response

Staff is concerned that language in Sections Section 7.6 and 6.7 of the plan which references a court decision "could lead to a more comprehensive challenge to ISO-supplied demand response compensation," as the Proposed Plan phrases it. Nevertheless, Staff firmly supports the IPA's decision to avoid making any rash and ultimately futile moves to develop utility-level substitutes for the demand response programs of PJM and MISO. (Staff Objections at 28-29)

According to Staff, the IPA's authority to pursue demand response is limited to the demand response of eligible retail customers, who are a small part of the traditional and current demand response marketplace which is dominated by large retail customers. (Staff Objections at 29)

Staff states that while demand response had been an important element of utility tariffs and resource planning for decades, as the responsibility for maintaining reliability has shifted from individual utilities to ISOs like PJM and MISO, demand response programs have become important elements of ISO tariffs and planning. Staff believes reaping anywhere close to the full value of demand response depends critically on the willingness and ability of the ISOs to recognize that demand response as a resource that can substitute for supply. In Staff's view, it is absolutely crucial that the ISOs continue to be central to demand response; and it is equally crucial that ISOs be closely involved in developing potential replacements for their present demand response programs, if that ultimately becomes necessary. Staff is confident that, one way or another, this will be the case. Staff says, as the IPA implies, presently, we must wait for the courts to resolve some of the jurisdictional issues. (Staff Objections at 29)

The Commission notes that no party responded to Staff on this issue and it appears unnecessary for the Commission to take any action with regard to this matter.

H. Miscellaneous and Technical Issues

According to Ameren, Tables 7-6, 7-7, 7-8 and 7-9 appear to contain quantities that are representative of the July 2014 expected load forecast without consideration for additional energy efficiency. Ameren says this is in contrast to the footnote which states that the volumes will be based on the March 2015 forecast including newly approved energy efficiency programs. Ameren suggests the footnote for each of the tables, found on pages 88-90 be changed to say:

> Volumes are based on the July 2014 expected load forecast without consideration for incremental energy efficiency programs. Assuming approval of incremental energy efficiency programs by the Commission, the actual quantities will be based on the March 2015 expected load forecast including adjustments for incremental energy efficiency programs.

Ameren also states that Tables 7-14, 8-1 and 8-3 appear to contain quantities that are representative of the July 2014 expected load forecast without consideration for additional energy efficiency. Ameren suggests a footnote be added to those tables found on page 98, 101 and 103, respectively, which says:

> Volumes are based on the July 2014 expected load forecast without consideration for incremental energy efficiency programs. Assuming approval of incremental energy efficiency programs by the Commission, the actual quantities will be based on the March 2015 expected load forecast including adjustments for incremental energy efficiency programs.

Ameren appreciates the additional explanations provided by the IPA and has no further comment at this time.

For clarity and at the request of certain parties, Ameren would like to make clear that the amounts set forth in the budgets identified in Table 7-2 of the Plan (found on page 79) reflect the total budgets for both the gas and electric portions of the proposed behavioral modification programs. Ameren says the gas portion for both programs, which represents the budget approved for Ameren's Section 8-104 gas portfolio, equals $2,244,375. Accordingly Ameren seeks approval of only the electric portion of either of these budgets, or $2,311,065 for Home Energy Reports or $2,244,375 for Behavioral Energy Efficiency. (Ameren Reply at 13-14)

Ameren suggests that the footnote for Tables 7-6 through 7-9, found on pages 88-90 of the Plan, be edited. The IPA disagrees that this edit is necessary. (IPA Response at 46-47)

The IPA believes that the existing footnote, taken in combination with the text in the Plan, provides sufficient clarity that the forecasted volumes are based on an expected load forecast without consideration for incremental energy efficiency programs, and that the March 2015 and July 2015 load forecasts are expected to include approved energy efficiency programs for both Ameren and ComEd. Thus, the IPA does not support this change. (IPA Response at 47)

Ameren also suggests a footnote be added to Tables 7-14, 8-1, and 8-3. The IPA believes this additional footnote is unnecessary for Table 7-14 for the reason stated above. The IPA suggests, for the sake of clarity, adding the suggested footnote to tables 8-1 and 8-3, as well as to tables 8-2 and 8-4, which reference ComEd, is a reasonable suggestion and the IPA supports its adoption. (IPA Response at 47)

Having reviewed the parties' positions, with the exception of the modifications identified by the IPA immediately above regarding Tables 8-1 through 8-4, the Commission believes the Plan is sufficiently clear. The Commission declines to adopt Ameren's other proposed modifications to the Plan.

I. Pre-Bid Letters of Credit

Ameren claims the pre-bid letter of credit held by it is used primarily to protect customers from a scenario where winning suppliers do not execute contracts and this in turn results in higher supply costs. The IPA has also identified that it has risk under a scenario where winning suppliers do not pay for fees associated with procurement events. The IPA has therefore proposed that Ameren and the IPA have a side agreement whereby under certain circumstances Ameren could draw on funds associated with the pre-bid letter of credit and reimburse the IPA for unpaid supplier fees. (Ameren Objections at 7-8)

Ameren believes the solution that provides the best credit protection for both Ameren and the IPA is for Ameren and the IPA to hold separate pre-bid letters of credit from suppliers. Ameren says it recognizes that doing so may create additional administrative burden and cost to the IPA and suppliers. Therefore, Ameren does not oppose the IPA proposal; however it desires to make the Commission aware that the pre-bid letter of credit has limited funds available for drawing. Ameren says this is especially pertinent to a scenario where the Commission approves a procurement and winning suppliers fail to execute contracts and fail to pay supplier fees. Ameren believes that the side agreement should state that funds are available to the IPA only to the extent that they are not required by Ameren. (Ameren Objections at 8)

Ameren does not oppose the IPA's proposal to include a condition in the pre-bid letter of credit by which the utility could withdraw funds in the event that a supplier fails to pay the supplier fee. Neither does Ameren oppose entering into a side agreement with the IPA which would state that funds are available to the IPA only to the extent that they are not required by Ameren. The IPA agrees that this arrangement is not a perfect credit hedge for the IPA in the event that the Commission approves a procurement and the winning supplier fails to execute contracts and fails to pay the supplier fee. The IPA believes, however, that this arrangement does reduce administrative burden and cost for the suppliers and to some less degree for the IPA, and continues to support adoption of its proposal. (IPA Response at 46)

Based on the above, the Commission approves and finds in favor of the Ameren and IPA compromise. Ameren and the IPA have reached agreement regarding how to proceed with pre-bid letters of credit for 2015/2016. The two parties have agreed to enter into an agreement in 2015/2016 whereby funds from the pre-bid letter of credit will be available to the IPA to meet a shortcoming in supplier fees, but only to the extent that funds are not required by Ameren under a scenario where suppliers fail to execute contracts after Commission approval of an IPA procurement.

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 legal argument identified as the parties respective positions are supported by the record;

(4) the recitals of fact and conclusions of law reached in the Commission Conclusion portions of this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law for purposes of this Order;

(5) the load forecast for AIC attached to the IPA's September 29, 2014 petition should be approved; the load forecast for ComEd attached to the IPA's September 29, 2014 petition should be approved;

(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;

(7) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

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 17th day of December, 2014.

(SIGNED) DOUGLAS P. SCOTT

Chairman