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)

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 the Commission has previously found 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.

Having reviewed the IPA Act and the PUA, the Commission concludes that any energy efficiency programs to be undertaken by the IPA must be pursuant Section 16-111.5B of the PUA. The IPA, CUB, and the AG fail to identify any other provision in the IPA Act or the PUA which would govern additional energy efficiency procurements. While all provide sound policy arguments in favor of the IPA's proposal, the Commission and the IPA are limited to taking actions authorized by the Illinois General Assembly.

Perhaps in light of this limitation, the IPA proposed an alternative proposal in the event the Commission rejected its primary proposal. 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 also believes such efforts should be pursued pursuant to Sections 16-111.5 and 16-111.5B of the PUA. Because neither ComEd nor Ameren presented energy efficiency proposals consistent with the IPA's stated objectives, it is not possible for the Commission to approve the IPA's alternative proposal at this time. That does not mean; however, that it should simply be dismissed.

The Commission directs the parties to commence workshops, coordinated by Staff, to pursue the IPA's alternative proposal. 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 Sections 16-111.5 and 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)

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 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, then 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)

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 Commisson:

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)

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 demand reduction induced price effects (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 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 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 for 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 Utiltiy 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	1.19
Small Business Refrigeration	17,947	17,947	$7,571,125	1.09
Demand-Controlled Ventilation	5,318	-	$1,146,840	1.2

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.

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 it should 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 that 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 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 as outlined in Section 16-111.5B. (Staff Objections at 17)

The Proposed Plan states that 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. 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 has also shown that 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 that 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 be arguing that 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 that 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 versus 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 it appears 138,769 new households, which is more than double the amount of new households that 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. Staff states that reviewing the Ameren electric energy savings results, they 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)

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)

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)

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)

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)

9. Commission Analysis and Conclusions

NRDC urges the Commission to require the inclusion of marginal line losses, DRIPE, and NEB 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.

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 not participating in this proceeding. They believe the Commission should refer the issue to workshops conducted either by Staff or the SAG. NREC 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. Additionally, the Commission directs those parties opposed to NRDC's recommendation to seriously reconsider their opposition. In particular, the Commission is troubled by Ameren's refusal to consider utilizing its best estimate of marginal line losses in place of average line losses, which ComEd already utilizes. Additionally, it appears possible that ComEd is relying on outdated literature 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. Finally, the Commission notes that even the IPA appears to be considering the possibility that NRDC's recommendations may have merit. 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, 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. The Commission finds the quality of evidence relating to this issue somewhat disappointing. There is essentially no evidence regarding Ameren specific overhead or administrative costs though it is almost certain they exist. 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.

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.

The Commission notes that, to some extent, the schedule for the third party bid process is out of the utilities' control 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. The Commission will be disappointed if it hears similar complaints to those raised by NRDC and ELPC in future proceedings. Again, while the Commission does not wish to initiate a formal proceeding to address this issue, 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. Unfortunately, the Commission finds Staff's recommendations and arguments, as well as the IPA's responses, somewhat confusing. 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.

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 phase "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 date certain, 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)

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)

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, that is 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 (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. However, ISEA states 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 Solar Renewable Energy Credits (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 [Alternative Compliance Payment ("ACP")] funds to allow the utilities to meet their [distributed generation ("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)

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 wonders how and when these assets be uniquely identified. ISEA also wonders 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 wonders 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 Renewable Portfolio Standard ("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." However, 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).” 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. Section 16-111.5(e) requires that bids be selected “solely on the basis of price” (220 ILCS 5/16-111.5(e)), 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. ISEA says many states, including Massachusetts and New York, have acknowledged the need to independently incentivize small commercial projects. ISEA asserts 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 understand 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 object to and question 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. However, per the contract tendered by ComEd for the purchase of curtailed 2014-2015 RECs using HACP funds, the RS says FPL Illinois 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 asking the Commission to 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 take 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)

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 has 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 only 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 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 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:

- Documents used for project identification – 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.
- Cancellation for non-performance – The contract amount would only be reduced for non-performance and not outright cancelled.
- Contract length/performance start date – 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. (OPA Response at 46)

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)

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)

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 ELPS, ISEA, and to a lesser extent by Ameren. Among other things, they 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 ELPS and ISEA proposal is the lack of stability in the funding source for this particular procurement. 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 1-75(c) of the IPA Act. 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. That ComEd's proposal could easily result in a procurement from only facilities larger than 25 kilowatts 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. The Commission therefore approves the IPA's proposed credit deposit of $10 per REC for the purposes of this procurement Plan.

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. 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. 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. ComEd proposed different language intended to accomplish the same goal. 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. It appears the RS did not reply to ComEd's proposed language. 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, it wants the Commission to intervene with respect to future contracts regarding curtailed RECs. The Commission also finds it troubling that ComEd, apparently, does not communicate with the RS to obtain its input on contract terms and conditions before having the contract approved by the IPA and Staff. The Commission notes this is not the first time this type of complaint has been raised by the RS. In the future, the Commission directs ComEd to obtain the input of the counterparty, in this case the RS, before having contracts concerning curtailed RECs approved by the IPA and Staff.

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 wellfounded 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)

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)

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)

10. IIEC's Position

IIEC supports the recommendations of the IPA, Staff, Ameren, ComEd, and ICEA to reject the Sargas request.

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, the parties opposed to the Sargas proposal 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 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 court 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.

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.

DATED: November 13, 2014

Michael L. Wallace
Chief Administrative Law Judge

Briefs on Exceptions due November 21, 2014.
Reply Briefs on Exceptions due December 1, 2014.