STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER AGENCY	:	
	:	**Docket No. 14-0588**
Petition for Approval of the 220 ILCS 5/16-111.5(d) Procurement Plan	:	
	:	

STAFF OF THE ILLINOIS COMMERCE COMMISSION

RESPONSE TO OBJECTIONS TO PROCUREMENT PLAN

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Pursuant to the October 8, 2014 Notice of Chief Administrative Law Judge's Procedural Ruling, the Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, respectfully submits this Response to Objections to the Illinois Power Agency's ("IPA") 2015 Procurement Plan ("Plan," or "IPA Plan," or "Proposed Plan"). Staff also submits the Affidavits of Richard J. Zuraski, Dr. David Brightwell, and Jennifer H. Morris in support of facts and non-legal matters contained herein.

I. <u>BACKGROUND</u>

On September 29, 2014, the IPA filed its 2015 Plan for the five year procurement planning period from June 2015 through May 2020 with the Illinois Commerce Commission ("Commission") thereby initiating this docket.

On or about October 6, 2014 pursuant to Section 16-111.5(d)(3) of the Public Utilities Act ("PUA"), Staff and the following sixteen parties served on each other and filed Responses and/or Objections to the Plan:[1]

[1] The Plumbers & Steamfitters' Objections were not served on the parties until October 9, 2014.

Illinois Competitive Energy Association ("ICEA"),

Commonwealth Edison Company ("ComEd"),

Ameren Illinois Company ("Ameren Illinois," "Ameren," or "AIC"),

Retail Energy Supply Association ("RESA"),

Renewable Suppliers,

Exelon Generation Company ("Exelon" or "ExGen"),

Environmental Law and Policy Center ("ELPC"),

Sargas Inc. ("Sargas"),

Citizens Utility Board ("CUB"),

International Brotherhood of Electrical Workers Local 146 ("IBEW 146"),

International Brotherhood of Electrical Workers Local 363 ("IBEW 363"[2]),

Illinois Coal Association ("ICA"),

Illinois Solar Energy Association ("ISEA"),

Natural Resources Defense Council ("NRDC"),

Plumbers & Steamfitters Local 149, United Assoc. ("Plumbers & Steamfitters"),[3] and

Lincoln Land Trade Council.[4]

On October 8, 2013, the Chief Administrative Law Judge of the Commission provided notice that, "pursuant to Section 16-111.5(d)(3) of the Public Utilities Act, no hearing in the above-referenced matter is determined to be necessary." A separate Chief Administrative Law Judge procedural Ruling provides for the filing of: Verified Responses to Objections and Verified Replies to Responses, due October 21, 2014 and October 31, 2014, respectively. (October 8, 2013 Chief ALJ Ruling.)

[2] The ALJ Notice of October 14, 2014 stated in part that "objectors who have not filed petitions for leave to intervene will not have the objections considered." As of October 21, 2014, Plumbers & Steam Fitters has not filed a petition to intervene. Staff assumes at some point this party will file a petition to intervene.

[3] As of October 21, 2014, IBEW 363 has not filed a petition to intervene. Staff assumes at some point this party will file a petition to intervene.

[4] As of October 21, 2014, Lincoln Land Trade Council has not filed a petition to intervene. Staff assumes at some point this party will file a petition to intervene.

II. ARGUMENT

A. Fixed Price Full Requirements

ICEA proposes modifying the plan to include a limited pilot, whereby 25% of the total load of eligible retail customers for each of the next four years would be served through Fixed Price Full Requirements ("FPFR") contracts. (ICEA Objections, 8.) RESA and Exelon support ICEA's proposal, while CUB opposes it.

CUB opines that such a proposal should be rejected, arguing in part that "[s]uch a study is inappropriate in that it would not, in its own right, provide price stability for Illinois consumers, nor would doing a pilot inform the IPA as to the willingness of consumers to pay for price stability." (CUB Objections, 2.)

Staff neither supports nor opposes ICEA's proposal. In Staff's view, the issues surrounding FPFR contracting have been thoroughly discussed and are ready to be addressed by the Commission. However, Staff disagrees with one of CUB's arguments. While CUB is correct that a 25% pilot program "would not, in its own right, provide price stability for Illinois consumers," this CUB criticism overlooks the benefits of such a pilot. The value of such a pilot would be to provide side-by-side comparisons between the bidding results of a fixed-price fixed-quantity (block) procurement and a FPFR procurement, conducted nearly simultaneously and for the same delivery periods. Such experiments would provide additional relevant data on the relative cost of the two procurement approaches.

B. One-Year Solar REC Procurement

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 ("solar RECs" or "SRECs") 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." (ISEA Objections, 3.) According to ELPC, "There is ample evidence from Illinois and elsewhere that new PV resources cannot be developed using one-year SREC contracts." (ELPC Objections, 2.) Both intervenors recommend offering five-year contracts to potential SREC suppliers. Staff disagrees.

First, 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. 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.

Second, 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. 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 Illinois Power Agency Act ("IPA Act"). IPA procurement events are only one prong of a multi-pronged, multi-jurisdictional approach of encouraging growth in the utilization of solar power. Furthermore, Illinois law makes no distinction between new and old generating resources when it comes to the purchase of RECs. 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. 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. Indeed, many goods and services are sold without ***any*** explicit contracts. Hence, 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.

Third, 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, there is an argument for not procuring any SRECs for 2015-2016, since the ***total*** REC target has already been met. As Ameren Illinois states:

> [T]here is not a clear requirement that REC subtargets must be met in a year where the total REC target has been exceeded.
>
> * * *
>
> Ameren Illinois 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 Illinois eligible retail customers by approximately $0.50/MWh.

(Ameren Illinois Objections, 5.) ComEd echoes Ameren's position. (ComEd Objections, 21-22.)

Fourth, ELPC and ISEA fail to adequately address the budgetary issue. As the IPA states:

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

(IPA Plan, 100.) Without an assured base of eligible retail customers from whom to collect the costs incurred by the utilities over a five year period, 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.

The risk of running out of funds in the middle of a 5-year contract term can be mitigated, however, by reducing, at the time of the procurement event, the budget available. How far to reduce the budget is a matter of judgment.

Staff recommends rejecting the ELPC and ISEA proposed 5-year SREC procurement. However, 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, 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. This is shown below, with the budget caps rounded to the nearest $1000 and the contract price adjustments rounded down to the nearest tenth of 1 percent.

June to May REC Delivery Period	Budget Cap for 5-Year Contract		Contract Price Adjustment	
	Ameren	ComEd	Ameren	ComEd
2016-2017	$1,380,000	$2,280,000	100.00%	100.00%
2017-2018	$1,860,000	$2,210,000	134.70%	96.90%
2018-2019	$2,550,000	$2,420,000	184.70%	106.10%
2019-2020	$2,550,000	$2,380,000	184.70%	104.30%
2020-2021	$2,670,000	$2,620,000	193.40%	114.90%

To be clear, the budget caps above, 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. Similarly, the contract price adjustments shown in the table above would also remain at the levels shown.

Finally, even though the budgets for the 5-year contracts (shown in the above table) are equal to only one-half the ***projected*** remaining budget available, this does not guarantee that the ***actual*** remaining budget will be sufficient. That is, 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. History provides a cogent example. 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. Hence, 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. 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. In any event, the pecking order should be clearly specified prior to the new procurement event.

C. Distributed Generation Procurement with Hourly Customer ACP Revenues

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 Objections, 35-36.)

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 3rd Party Administrator for systems <25kW and that a standard offer price be given to all small systems.

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. However, neither ISEA nor ELPC suggest alternatives.

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.

To some extent, Staff is sympathetic to the concerns of ISEA and ELPC. However, some of their recommendations should be rejected. For example, they recommend use of a 3rd Party Administrator for systems <25kW and that a standard offer price be given to all small systems. To some extent, they misunderstand the IPA's proposal. There is nothing in the IPA's proposal that would prevent an aggregator from making its own standard offer to owners of systems <25kW. The issue is whether the IPA is permitted to make a "standard offer." As previously explained by Staff, it is clear that:

> [T]he 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. Among other things, 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)). 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.

(Staff Objections, 36.)

The Commission should also reject the ISEA and ELPC proposal to split the 25 kW – 2 MW category into two sub-categories. 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. However, ISEA and ELPC present no coherent rationale for spending more to purchase the smaller systems within the 25 kW – 2 MW range. While the law clearly expresses a preference for purchasing RECs from systems both above and below the 25 kW level, the law expresses absolutely no preference or requirement to split these systems into additional sub-categories. 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.

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. As ComEd explains it:

> 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). To date, all eligible bidders have been welcomed to participate, and the Procurement Administrator ("PA") 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, the PA 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, the PA 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.

(ComEd Objections, 23-24.) 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. That is not to say that this past practice is the ***only*** reasonable means of implementing those provisions.

On the other hand, 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. Indeed, it appears to Staff that the IPA is planning on using a single procurement fully consistent with past practice. First, the IPA refers to it as "a single procurement event." (IPA Plan, 107.) Second, 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." Id. Third, 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. It refers to the "ACP funds being held as of May 31, 2014: for Ameren Illinois, the value is $5,556,580; for ComEd, the value is $7,842,658." (Id., at 104.) However, it does not break up these funds into <25 kW segments and a 25 kW to 2 MW segments. Presumably, the IPA will clarify its intent in its own reply to ComEd's Objections. 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 it is imperative that the Commission, prior to those procurement events, approve separate budgets or authorize the IPA to adopt separate budgets.

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:

> Ameren Illinois 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 Illinois. To compensate the IPA for DG REC expenses under its contract, the Commission would order Ameren Illinois to transfer funds to the IPA based on prior Ameren Illinois collections from real time pricing customers. The Commission would also stipulate that the total dollar value of DG REC contracts would not exceed funds already collected by Ameren Illinois 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 Illinois and the IPA with a more systematic distribution of funds when supplier invoices are received by the IPA. Finally, the Commission should 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. The 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 Illinois Objections, 7.) 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. Furthermore, linking the regular Plan's proposed DG procurement with the supplemental solar photovoltaic procurement may reduce confusion among potential bidders and retail customers. Finally, 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. However, it is not clear 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.

Nevertheless, Staff cannot support Ameren’ proposal for the simple reason that it is not authorized by statute. The statute clearly 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).

D. Clean Coal

In their Objections, Sargas, ICA, IBEW 146, IBEW 149, IBEW 363, Plumbers & Steamfitters, and Lincoln Land Trade Council, all argue for the IPA Plan to include a clean coal procurement. As support for their position, those parties, except for Sargas, cite to job creation and clean coal market growth as reasons for including a clean coal procurement in the Plan. 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.” 220 ILCS 5/16-111.5(j)(ii). Nowhere do those parties address that standard. For this reason alone, the parties’ suggested change to the Plan should be rejected.

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 Objections, 12.) 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. Id. 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. (Id., at 7.) 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[.]" 220 ILCS 5/16-115(d)(5)(iii). Also, 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. 20 ILCS 3855/1-75(d)(1). 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, 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.

Finally, as Staff pointed out in its Comments and Objections to the Plan and as the IPA recognized in its discussion of clean coal in the Plan, 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 Objections, 30.) Yet Sargas' proposal has Commission approval of a sourcing agreement as a critical element of its proposal ("Sargas proposes that the IPA award a 20-year power purchase agreement" between successful bidders and ARES and Illinois electric utilities.") In its Objections, Sargas cites to the recent Appellate court case, Commonwealth Edison Co. v. Ill. Commerce Comm'n, 2014 Ill App (1st) 130544 (July 22, 2014) to support its position, but the facts in that case are far different then what Sargas is proposing here. That ComEd case involved FutureGen, a retrofit clean coal facility. Retrofits have a specific statutory section dealing with them (Section 1-75(d)(5) of the IPA Act). Sargas' planned facility and other standard non-delineated clean coal facilities are treated much differently than retrofits and the initial clean coal facility under the IPA Act and PUA. Those non-delineated clean coal facilities fall under Section 1-75(d)(1). 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. As discussed above, only the benchmark for such facilities is addressed in Section 1-75(d)(1). There simply is no authority to approve a sourcing agreement as Sargas proposes, similar to the manner in which one was approved for FutureGen. 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. Based upon the above, Staff recommends that the Commission reject Sargas' request for a new competitive procurement for standard non-delineated clean coal facilities in the Plan.

E. Incremental Energy Efficiency

1. Ameren Illinois

a) TRC Workshops

Ameren Illinois states that the post procurement plan proceeding Total Resource Cost Test ("TRC") workshops recommended by the IPA should be conducted through the Illinois Energy Efficiency Stakeholder Advisory Group ("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." (Ameren Objections, 15.) 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 discussed further below. As an initial matter and as a point of clarification, meeting notices and other information concerning the Section 16-111.5B energy efficiency workshops Staff held following the Commission's Order in ICC 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. (*See e.g.,* Appendix B-2 (Workshop Summaries) – 2015 Procurement Plan, 4, 31.) Thus, for clarity of the record, regardless of whether Staff or the SAG hosts the TRC workshops, ***all*** interested parties, including other utilities in Illinois not participating in this docket, would be able to participate in addressing the TRC issues.

Nevertheless, as noted above, Staff has no objection to Ameren's proposed language change to the IPA Plan that would shift responsibility from Staff to the SAG. Indeed, in the Commission's Orders in the energy efficiency plan dockets (i.e., ICC 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. *See e.g.,* Ameren Illinois Co., ICC Docket No. 13-0498, Order at 129 (Jan. 28, 2014). Thus, 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.

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" [5] 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. Accordingly, the Commission should adopt the following language changes to page 80 of the Proposed Plan:

> While the IPA does not recommend altering those calculations at this time because Ameren Illinois performed those calculations using reasonable assumptions per the review of Section 8-103 programs, the IPA recommends that ~~ICC Staff~~ the SAG hold workshops in early 2015 to

[5] The last SAG meeting was held July 29, 2014. The IL EE SAG facilitator informed the SAG e-mail distribution list on August 7, 2014 that "Until the funding issue is resolved, the EE SAG activities, except for the Technical Reference Manual Process, are suspended." A recent update provided October 21, 2014 seems to indicate the SAG may resume with a meeting starting October 28, 2014, and the funding of the SAG facilitator has been confirmed through May 2016.

> examine if the inputs used for the Section 16-111.5B TRC calculations should be different from those used for the Section 8-103 programs, and to develop recommendations for use in next year's filings.[6] The workshop could also consider if the IPA should develop and perform an independent TRC calculation with distinct inputs and assumptions rather than relying on inputs provided by the utilities. In their July 15, 2015 energy efficiency assessment submittals to the IPA required by Section 16-111.5B, the utilities should summarize the results of the Spring 2015 TRC workshops, including identification of areas where consensus (i.e., no objecting party) was able to be reached among all interested parties along with rationale supporting such consensus recommendations. Further, the IPA will report to the Commission on the results of the TRC workshops in its 2016 procurement plan. In the event the SAG does not have time to adequately address such TRC issues given SAG's other responsibilities and priorities, the utilities are required to host the aforementioned TRC workshops beginning in January of 2015, and the utilities shall encourage all interested parties to participate in the TRC workshops and should make best efforts to ensure all interested parties are made aware of the TRC workshops.

(IPA Plan, 80.)

2. NRDC

The NRDC's summary of one of its objections is:

> 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. The NRDC recommends that the calculations for these three programs be adjusted so that demand reduction induced price effects (DRIPE), marginal line losses, and an accurate non-energy benefits adder are included and any non-essential administrative costs are excluded.

(NRDC Objections, 2-3.)

a) Marginal Line Losses

Staff 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

[6] Changes to be considered could include, but not be limited to, the suggestions of NRDC to include demand reduction induced price effects, different line losses, and a non-energy benefits adder. Additionally, should the Commission approve the EEASR alternative proposal contained in Section 7.1.5, the workshop could consider the methodology for considering a time-sensitive avoided energy cost.

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. (IPA Plan, 80.) The Commission need not make a determination on the marginal line loss issue until after the TRC workshops are complete.

b) Administrative Costs

The accurate inclusion of costs includes costs that Staff understands NRDC to characterize as "non-essential administrative costs." These costs include items such as the cost to evaluate a program and the cost to administer the contracts associated with a program. Within the energy efficiency ("EE") 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. However, in the context of the Section 16-111.5B EE programs, it is more appropriate to include these types of costs within the program-level TRC analysis. The reason being that there is not a portfolio in Section 16-111.5B in the same context as there is under Section 8-103 of the PUA. Specifically, 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, 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. 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. 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 the IPA Act. 20 ILCS 3855/1-10 ("A total resource cost test compares…the benefits…to the sum of ***all incremental costs***…(including both utility and participant contributions), ***plus costs to administer, deliver, and evaluate each demand-side program***..." (emphasis added)). Accordingly, the Commission should reject NRDC's proposal to remove real administrative costs from Ameren Illinois' TRC analysis of the vendors' programs bid under Section 16-111.5B as such a proposal is clearly 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.

c) DRIPE

The Commission should reject the inclusion of so-called demand reduction induced price effects ("DRIPE") that are mentioned in the NRDC's second objection. 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 the IPA Act. 20 ILCS 3855/1-10. Additionally, 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.[7]

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, that customer has additional money equal to $1 times the number of units of the item that are purchased to use as desired. However, referring to this as a societal benefit is incomplete as customers are only one type of economic agent in a society. There is also the effect of the lower price on producers. In this case, 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. The result is that on net, society neither benefits nor loses from the lower electric price. From a societal perspective, DRIPE represent nothing more than a transfer of wealth towards customers and away from producers. It is neither a societal benefit nor a societal cost. In economic parlance, DRIPE would be referred to as a "pecuniary externality," as opposed to a "real" or "technological" externality. Pecuniary externalities are pervasive in markets. However, unlike real externalities, pecuniary externalities have no impact on economic efficiency and provide no justification for government intervention on economic efficiency grounds.[8]

[7] *See* "Analysis of Electric Energy DRIPE in Illinois." (NRDC Comments, 12, referenced in Footnote 8 of NRDC Objections, 4.)

[8] *See,* for example, Holcombe, Randall G., and Russell S. Sobel, "Public Policy Toward Pecuniary Externalities," *Public Finance Review*, Vol. 29 No. 4, July 2001 304-325; as well as Gillingham, Kenneth, and James Sweeney, "Market Failure and the Structure of Externalities," in *Harnessing Renewable Energy in Electric Power Systems: Theory, Practice, Policy,* Moselle, Boaz, Jorge Padilla, and Richard Schmalensee, editors, 2010, p. 71.

The Vermont Public Service Board makes a persuasive economic argument against counting DRIPE in a TRC test and states:

> The Board is persuaded by the arguments made by the Department and participating utilities that, from a societal perspective, the benefits associated with DRIPE (lower regional energy and capacity market clearing prices) are offset by the reduction in payments to owners of generation resources resulting from the lower market clearing prices. Therefore, while it may be appropriate to consider DRIPE in a bill impacts analysis since those analyses focus solely on the energy customer's perspective, it is not appropriate to consider DRIPE in cost-effectiveness screening since the societal test considers the effects on society as a whole, which includes both customers and producers. Accordingly, the Board concludes that an adjustment for DRIPE should not be included in the cost-effectiveness screening of efficiency investments in Vermont.

Vermont Public Service Board, Memorandum from Susan M. Hudson, Clerk of the Board, to EEU-2011-01 (Cost-Effectiveness Analysis) E-mail Service List, Re: Request to Consider adjustment for DRIPE in EEU Cost-Effectiveness Analysis of Efficiency Investments, August 18, 2011, 3.[9] Relying on much less cogent arguments, the Vermont board subsequently changed its position on DRIPE. Vermont Public Service Board, Order Re: Demand Reduction Induced Price Effect, Docket EEU-2013-07, April 4, 2014.[10]

Furthermore, the price reductions associated with artificially created DRIPE (*e.g., by misusing DRIPE to justify uneconomic energy efficiency programs*) is only temporary. As already noted, 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. To use economic parlance again, these are changes in

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[9] http://psb.vermont.gov/sites/psb/files/projects/EEU/2009avoidedcosts/Memo_re_avoided_costs_DRIPE.pdf

[10] http://psb.vermont.gov/sites/psb/files/orders/2014/2014-04/ORDreDRIPE.pdf

"consumer surplus" and "producer surplus." However, in a regulated or competitive market for energy (where economic profits tend toward zero[11]), producer surplus is used as a means of recovering at least some portion of fixed costs. Thus, as producer surplus is reduced, something else must change. For example, 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.[12]

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 the Commission should not, the Commission should reject the numerical findings provided by NRDC in the memo attached to its Initial Comments.

NRDC provided the linear regression models and data used in the memo (NRDC response to Data Request Staff-NRDC 1). The basic form of the models is $LMP_t = B_0 + B_1$*$Local\_Load_t + B_2$*$Load\_Else\_Where_t$. The implication of the model specifications is that the change in load causes a change in price. From this assumption, the memo's authors reason that a program that reduces load by X units will have an associated price reduction that is a benefit to consumers.

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[11] There is a difference between economic and accounting profits. Economic profits include implicit costs such as the returns to alternative uses of capital investment. The result is that economic profits tend toward zero whereas accounting profits will be positive.

[12] For a similar analysis in the context of adding renewable energy generating capacity, see Lesser, Jonathan A., "Gresham's Law of Green Energy," *Regulation*, Winter 2010–2011, 14-16, available from http://object.cato.org/sites/cato.org/files/serials/files/regulation/2010/12/regv33n4-3.pdf.

Staff's review leads it to conclude that the models are only measuring a correlation between locational marginal prices ("LMP") and load. The models lack the sophistication to determine the direction of causality between LMPs and Load. It is very likely that there is feedback between prices and loads that would cause the benefits to be overstated. Within the memo, the authors note that some models produced what the authors felt were implausible results and that these model specifications were ignored (*see* page 18 of NRDC's Objections which is page 7 of the memo). Specifically, the authors felt it was implausible to have "negative coefficients (indicating that higher load in some regions would decrease prices in Illinois) or implying that a MWh load reduction downstate would reduce ComEd prices more than a MWh reduction in Chicago." Id.

Staff agrees that if the models are correctly specified, these results are implausible. However, given the problematic model specifications such results are far from implausible or unrealistic. The results are merely contrary to the authors' expectations. The regression analysis appears to suffer from what is commonly referred to in the econometrics literature as an identification problem. Such problems arise, for example, 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, 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, regression results are not meaningful and often appear to be implausible.

DRIPE represents a deviation from the typical calculation of the TRC and the approach historically adopted by the Commission. Consistent with the Commission's findings in the 2013 Procurement Plan, ICC 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. Illinois Power Agency, ICC Docket No. 12-0544, Order at 270 (Dec. 19, 2012).

III. CONCLUSION

Staff respectfully requests that the Illinois Commerce Commission consider Staff's Response to Objections to the IPA's 2015 Procurement Plan and the various recommendations contained herein.

Respectfully submitted,

/s/________________________

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Illinois Commerce Commission

October 21, 2014

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER AGENCY **Petition for Approval of the 2015 IPA Procurement Plan pursuant to Section 16-111.5(d)(4) of the Public Utilities Act**	: : : : : :	**Docket No. 14-0588**

AFFIDAVIT OF DR. DAVID A. BRIGHTWELL

State of Illinois)
)
County of Sangamon)

The undersigned, under oath, deposes and states as follows:

1. My name is Dr. David A. Brightwell. I am employed by the Illinois Commerce Commission as an Economist in the Commission's Policy Division.

2. I have read the Staff of the Illinois Commerce Commission's Response to Objections to the Illinois Power Agency's Procurement Plan dated October 21, 2014.

3. I have personal knowledge of the facts and matters discussed in the Response to Objections and, to the best of my knowledge, information and belief, the facts and non-legal opinions expressed in the Response to Objections are true and accurate and, if sworn as a witness, I could testify concerning them.

Further affiant sayeth not.

David Brightwell

Dr. David A. Brightwell

Subscribed and sworn to before me

This 21st day of October, 2014.

Lisa Bowman

Notary Public

OFFICIAL SEAL
LISA BOWMAN
Notary Public - State of Illinois
My Commission Expires Dec 9, 2015

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER AGENCY **Petition for Approval of the 2015 IPA Procurement Plan pursuant to Section 16-111.5(d)(4) of the Public Utilities Act**	: : : : : :	**Docket No. 14-0588**

AFFIDAVIT OF JENNIFER H. MORRIS

State of Illinois)
)
County of Sangamon)

The undersigned, under oath, deposes and states as follows:

1. My name is Jennifer H. Morris. I am employed by the Illinois Commerce Commission as an Economist in the Commission's Policy Division.

2. I have read the Staff of the Illinois Commerce Commission's Response to Objections to the Illinois Power Agency's Procurement Plan dated October 21, 2014.

3. I have personal knowledge of the facts and matters discussed in the Response to Objections and, to the best of my knowledge, information and belief, the facts and non-legal opinions expressed in the Response to Objections are true and accurate and, if sworn as a witness, I could testify concerning them.

Further affiant sayeth not.

Jennifer H Morris

Jennifer H. Morris

Subscribed and sworn to before me

This 21st day of October, 2014.

Notary Public

OFFICIAL SEAL
LISA BOWMAN
Notary Public - State of Illinois
My Commission Expires Dec 9, 2015

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER AGENCY	:	
	:	
Petition for Approval of the 2015 IPA Procurement Plan pursuant to Section 16-111.5(d)(4) of the Public Utilities Act	:	**Docket No. 14-0588**

AFFIDAVIT OF RICHARD J. ZURASKI

State of Illinois)
)
County of Sangamon)

The undersigned, under oath, deposes and states as follows:

1. My name is Richard J. Zuraski. I am employed by the Illinois Commerce Commission as an Economist in the Commission's Policy Division.

2. I have read the Staff of the Illinois Commerce Commission's Response to Objections to the Illinois Power Agency's Procurement Plan dated October 21, 2014.

3. I have personal knowledge of the facts and matters discussed in the Response to Objections and, to the best of my knowledge, information and belief, the facts and non-legal opinions expressed in the Response to Objections are true and accurate and, if sworn as a witness, I could testify concerning them.

Further affiant sayeth not.

Richard J. Zuraski

Subscribed and sworn to before me
This 21st day of October, 2014.

Notary Public

OFFICIAL SEAL
LISA BOWMAN
Notary Public - State of Illinois
My Commission Expires Dec 9, 2015