

**COMMENTS BY THE STAFF OF THE ILLINOIS COMMERCE  
COMMISSION ON THE ILLINOIS POWER AGENCY'S 2013 DRAFT  
POWER PROCUREMENT PLAN FILED AUGUST 15, 2012**

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Note: In these comments, aside from adding a “Conclusion” section, Staff retains the same outline that is used in the body of the Illinois Power Agency’s “2013 Electricity Procurement Plan,” which was distributed on August 15, 2012 (“the Draft Plan”). The table of contents in the Draft Plan, however, does not accurately reflect the outline used in the body of that document. Staff addresses only two of the inaccuracies in the table of contents. First, under Section 5.0, Staff recommends adding the two subsections that are excluded in the Draft Plan’s table of contents, as shown below:

- 5.0 MISO and PJM Resource Adequacy Outlook and Uncertainty
  - 5.1 [North American Electric Reliability Corporation \(“NERC”\) Reliability Assessments](#)
  - 5.2 MISO
  - 5.23 PJM
  - 5.4 [Resource Adequacy Uncertainty and Environmental Regulation](#)
  - 5.35 Overall Conclusions for Illinois

Second, under Section 8.0, Staff recommends adding the three subsections (8.1, 8.2, and 8.3) to the table of contents. The above two corrections are incorporated into the above table of contents in these comments. However, Staff has not corrected other differences between the body of the Draft Plan and its table of contents. For example, the table of contents lists Section 7.4 as “Ancillary Services and Capacity Products (Including Demand Response),” but it is called “Ancillary Services and Capacity Purchases” within the body of the Draft Plan.

## 1.0 Executive Summary

On August 15, 2012, pursuant to Section 16-111.5(d) of the Illinois Public Utilities Act, the Illinois Power Agency (“IPA”) made available to the public a “2013 Electricity Procurement Plan” (“the Draft Plan”) and invited affected utilities and other interested parties to submit comments on the Draft Plan by September 14, 2012. In response, the Staff of the Illinois Commerce Commission (“Staff”) hereby submits these comments to the IPA. The outline of these comments conforms to the outline of the Draft Plan.

Among other things, the Draft Plan’s Executive Summary outlines the following actions being proposed by the IPA:

- In order to deal with the risk associated largely with retail customer migration, the IPA recommends replacing its former 100%/70%/35% hedging strategy for energy products (i.e., 100% of the base case demand forecast hedged for the first year in the planning horizon, 70% hedged for the second year and 35% hedged for the third) with a 75%/50%/25% strategy. Staff supports this proposal.<sup>1</sup>
- Assuming no significant changes in the demand forecasts, the IPA recommends that there be no standard energy forward contracts procured during this 2013 planning cycle for any of the five 12-month delivery periods between June 2013 and May 2018. Staff agrees with this proposal.
- The IPA recommends retaining the 100%/70%/35% hedging strategy for purposes of Ameren’s capacity requirements until such time as MISO

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<sup>1</sup> Staff notes that this policy change does not affect plans for the June 2013-May 2014 delivery period. With existing contracts, the 24 hedge ratios during this period are already between 128% and 182% for ComEd and between 133% and 261% for Ameren (relative to the base-case forecasts).

demonstrates a robust FERC-approved capacity auction. Assuming no significant changes in the demand forecasts, the IPA recommends that Ameren meet any small remaining capacity requirements for the two 12-month delivery periods between June 2013 and May 2015 by participating in MISO's capacity auction; and that the IPA be authorized to conduct a capacity procurement during this 2013 planning cycle to acquire 35 percent of Ameren's projected capacity requirements for the 12-month delivery period between June 2015 and May 2016 (which would be 540 megawatts ("MW") of MISO Zonal Resource Credits). Staff agrees in part and disagrees in part with this recommendation. As explained more fully in Section 7.4.2, Staff recommends that the IPA amend the plan to eliminate the procurement of MISO Zonal Resource Credits during this 2013 planning cycle for the June 2015 and May 2016 delivery period.

- The IPA recommends that ComEd continue to meet all of its capacity requirements by paying PJM in accord with PJM's Reliability Pricing Model. Staff agrees with this proposal.
- Assuming no significant changes in the demand forecasts, the IPA primarily recommends that no new renewable energy resources be procured during this 2013 planning cycle, and that the alternative compliance payment funds held by the utilities and the IPA be reserved and made available, as needed, to permit ComEd and eventually Ameren to continue purchasing up to 100% of the contract quantities associated with the 20-year renewable energy contracts entered into pursuant to the request for proposals ("RFP") conducted by the IPA in December 2010. In the alternative, for Ameren, the IPA recommends that the

Commission approve a limited purchase of solar Photovoltaic RECs in this 2013 planning cycle for the 2013-14 delivery year, to the extent to which funds are available. Staff supports the IPA's primary recommendation with slight modification and clarification and takes no position with respect to the IPA's alternative recommendation for Ameren.

- For purposes of reporting each of the utilities' incremental spending pursuant to existing renewable energy resource contracts, the IPA recommends that it be authorized to use -- in this and subsequent procurement plans -- a blended average imputed renewable energy credit ("REC") price. The IPA presents such imputed values in the Draft Plan for the five 12-month delivery periods between June 2013 and May 2018. The values are imputed, in part, using a confidential forward price curve that was developed by the IPA's procurement administrator for the evaluation and management of the 20-year renewable energy contracts entered into pursuant to the RFP conducted by the IPA in December 2010. With a minor caveat, as explained in Section 8.0, Staff agrees with the IPA.
- The IPA recommends that the Commission direct Ameren and ComEd to pursue various new or expanded energy efficiency programs. Staff's review of these new or expanded energy efficiency programs is still ongoing. However, if, following that review, Staff concludes that these programs are likely to be cost-effective, Staff would support the IPA's recommendation.
- The IPA recommends that the Commission approve the form of a sourcing agreement between the FutureGen Alliance (as a seller of electricity) and ComEd, Ameren, Illinois ARES, and Illinois utilities operating in the service

territories of ComEd and Ameren (as the buyers), pursuant to Section 1-75(d)(5) of the Illinois Power Agency Act, dealing with retrofit clean-coal facilities. Staff finds this recommendation to be premature, due to the lack of any cost and rate impact projections presented in the Draft Plan and due to the lack of a proposed sourcing agreement. All that the IPA has presented is a draft sourcing agreement that the IPA admits is the subject of ongoing negotiations. The IPA presents no justification for the Commission to approve such an open-ended commitment on behalf of Illinois consumers. As detailed in Section 7.5, Staff recommends that the IPA significantly modify its proposal with respect to retrofit clean-coal facilities.

- The IPA recommends that the Commission approve the general parameters of a Distributed Generation program, without implementing the program until a later date to be determined in future procurement plan proceedings. As discussed in Section 8.0, Staff generally supports the IPA's proposal. Staff recommends a few modifications and clarifications.
- The IPA also indicates that it plans to implement various improvements to the procurement process. Staff will address these process improvement issues during the implementation phase of the plan.

## **2.0 Legislative/Regulatory Requirements of the Plan**

Generally, Staff has no objections to the content of this section of the Draft Plan. However, Staff recommends a slight rewording of two paragraphs, for the sake of accuracy.

First, on page 11, in an unnumbered subsection entitled, “Clean Coal Portfolio Standard,” Staff recommends the following changes:

The ~~PUA-IPA Act~~ contains an aspirational goal that cost-effective clean coal resources account for, 25% of the electricity used in Illinois by January 1, 2025.<sup>39</sup> To that end, the Plan must also include electricity generated from clean coal facilities.<sup>40</sup> While there is a broader definition of “clean coal facility” contained in the definition section of the IPA Act<sup>fn1</sup>, Section 1-75(d) describes two special cases: ~~There are two types of clean coal facilities described in the applicable legislation:~~ the “initial clean coal facility”<sup>41</sup> ~~and~~ “electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities (“retrofit clean coal facility”).<sup>42</sup> Currently, there is no facility meeting the definition of an “initial clean coal facility” that the IPA is aware of that has announced plans to begin operations within the next five years. However, the IPA is aware of a retrofit clean coal facility that intends to begin operations within the next five years.

The new footnote, labeled fn1, above, would be the following reference:

20 ILCS 3855/1-10.

Second, also on page 11, in the second paragraph of the unnumbered subsection entitled, “Retrofit Clean Coal Facilities,” Staff recommends the following changes:

By law, ~~the~~ the total amount paid under sourcing agreements ~~for~~ with clean coal facilities pursuant to the procurement plan for any given year shall be reduced by an amount necessary to limit the annual estimated average net increase in eligible retail customers’ electric service bills to certain levels that are specified in the IPA Act by a set of formulas ~~are subject to an escalating price cap.~~<sup>43</sup> Because the IPA does not anticipate ~~that~~ the operation of a ~~retrofit~~ clean coal facility until the 2017 delivery year, the maximum allowable increases in rates allowed by those formulas are known today to be equal to 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009.<sup>fn2</sup> For Ameren, this amounts to 0.2169 cents per kwh, and for ComEd, it amounts to 0.2382 cents per kwh.<sup>fn3</sup> ~~this Procurement Plan will not address the impact of the cost cap at this time, except in a general sense.~~

The new footnote, fn2, would be the following reference:

20 ILCS 3855/1-75(d)(2)(E).

The new footnote, fn3, would be the following:

Based on the amounts paid per kilowatthour by those customers during the year ending May 31, 2009, as reported in the Power Procurement Plan filed by the IPA on September 30, 2009 in Docket 09-0373. [http://www.icc.illinois.gov/e-docket/reports/browse/document\\_view.asp?id=9870&no=09-0373&did=141472](http://www.icc.illinois.gov/e-docket/reports/browse/document_view.asp?id=9870&no=09-0373&did=141472) Within that document, see specifically: Table Q, on page 41, where the Ameren Reference Year Unit Cost for the Reference Year 2008-2009 is shown to be \$107.66; and Table Y, on page 55, where the analogous ComEd value is shown to be \$118.23.

Finally, the existing footnote 43 should be corrected as follows:

20 ILCS 3855/1-75(d)(~~42~~)(D).

### 3.0 Load Forecasts

#### 3.1 Ameren

Staff generally has no objections to the content of this section of the Draft Plan. However, Staff recommends making the following change to add clarity to the headings in the first table, on page 12:

| Ameren Illinois Projected Average Demand for Eligible Retail Customers |  |          |  |          |  |          |
|--|--|----------|--|----------|--|----------|
|  | Average Load (MW)                                |          |  |          |  |          |
|  | 2013 Plan<br><a href="#">(Jul 2012 forecast)</a> |          | Spring 2012 Procurement<br><a href="#">(Mar 2012 forecast)</a> |          | 2012 Plan<br><a href="#">(Nov 2011 forecast)</a> |          |
|  | On-Peak  | Off-Peak | On-Peak  | Off-Peak | On-Peak  | Off-Peak |
|  |  |          |  |          |  |          |

#### 3.2 ComEd

Staff generally has no objections to the content of this section of the Draft Plan. However, Staff recommends making the following change to add clarity to the headings in the first table, on page 14:

| ComEd Projected Average Demand for Eligible Retail Customers |  |          |  |          |  |          |
|--|--|----------|--|----------|--|----------|
|  | Average Load (MW)                                |          |  |          |  |          |
|  | 2013 Plan<br><a href="#">(Jul 2012 forecast)</a> |          | Spring 2012 Procurement<br><a href="#">(Mar 2012 forecast)</a> |          | 2012 Plan<br><a href="#">(Nov 2011 forecast)</a> |          |
|  | On-Peak  | Off-Peak | On-Peak  | Off-Peak | On-Peak  | Off-Peak |
|  |  |          |  |          |  |          |

### **3.3 Load Forecast Uncertainty**

Staff generally has no objections to the content of this section of the Draft Plan. However, Staff recommends the following changes for the sake of accuracy and completeness:

First, in the second paragraph within Section 3.3.1 Customer Migration, Staff recommends the following modifications (footnotes omitted):

When restructured markets were phased-in in Illinois beginning in 1997, customer switching to ARES service was slow to take off in the residential and small commercial customer classes due, in part, to significant “transition charges,” which the utilities applied to ARES service customers’ bills, as well as to the existence of frozen bundled service rates. By January 2007, those factors no longer existed, but switching to ARES service remained slow due, in part, to the relatively high costs of customer acquisition and service for these smallest of utility customers. It was not until ComEd and Ameren began offering consolidated billing and purchase of receivables to ARES that residential and small commercial switching accelerated. ComEd and Ameren’s tariffs implementing Utility Consolidated Billing (“UCB”) and Purchase of Receivables (“POR”) became effective in August December of 2010 and August October of 2009, respectively. As an example of their positive marketplace impact, following the Commission’s approval of ComEd’s and Ameren’s tariffs, the number of residential customers taking ARES service in ComEd territory increased from essentially zero in March 2011 to over 70,000 in June 2011. From June 1, 2011 to August 12, 2011, residential enrollment with ARES in ComEd’s service territory averaged 1,150 customers per day. If that trend were to continue, ComEd projected last year that over a million residential customers could switch to ARES service by 2013-2014.

### **3.4 Recommended Planning Forecast Scenario**

Staff has no objections to this section of the Draft Plan.

## **4.0 Existing Resource Portfolio and Supply Gap to Be Filled**

Staff has no objections to this section of the Draft Plan.

#### **4.1 Ameren**

#### **4.2 ComEd**

### **5.0 MISO and PJM Resource Adequacy Outlook and Uncertainty**

Staff finds most of this section of the Draft Plan (specifically, subsections 5.1 through 5.5) to be insightful and well-written. However, Staff seeks clarification from the IPA, with respect to the first paragraph of 5.0:

From the perspective of the IPA Procurement Plan, resource adequacy should be viewed from two different angles. First, as wholesale electric markets are competitive, the process of acquiring resources could be considered solely a function of determining what level of resources to purchase from which markets over time. However, in order for these markets to properly function, there must be sufficient resources to satisfy the demand of all users. Thus, the second angle is whether there are sufficient incentives for resources to be available or forthcoming over the planning horizon to support a competitive market. In that case, the IPA could be in the position to augment the current resource markets by, for instance, seeking longer-term purchases or PPAs to incent development of generation. This section reviews the likely load/resource outcomes over the planning horizon to determine, if indeed, the current system is highly likely to provide the necessary resources such that customers will be served with adequate and reliable power.

IPA Draft Plan, p. 30.

Given the opening premise of the above paragraph -- that “wholesale electric markets are competitive” -- Staff seeks an explanation of the sentence, “However, in order for these [competitive wholesale electric] markets to properly function, there must be sufficient resources to satisfy the demand of all users.” A hallmark of competitive markets is that they serve to ration goods and services so that the quantities demanded equal the quantities supplied at the prevailing market prices. The next sentence in the Draft Plan states: “Thus, the second angle is whether there are sufficient incentives for resources to be available or forthcoming over the planning horizon to support a

competitive market.” Again, a hallmark of competitive markets is that prices – if high enough or expected to be high enough to support additional investment – provide the incentive for capital investment. Hence, in this paragraph, the Draft Plan seems to be implicitly rejecting its own premise: that “wholesale electric markets are competitive.”

Next, the IPA states, “In that case, the IPA could be in the position to augment the current resource markets by, for instance, seeking longer-term purchases or PPAs to incent development of generation.” However, it is unclear to what “case” the IPA refers. Is it the case where wholesale electric markets are competitive, or where they are not competitive; where they “properly function,” or where they do not function properly; where there are sufficient resources to satisfy the demand of all users, or where there are shortages; where there are sufficient incentives, or insufficient incentives for capital investment?

Especially after considering subsection 5.5 (“Overall Conclusions for Illinois”), the above critique of 5.0 may appear academic. Subsection 5.5 concludes that, for whatever reason (whether it is due to competition or other forces), there are no looming capacity shortages that might prompt the IPA to consider taking “extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.” (IPA Draft Plan, p. 40) Nevertheless, Staff maintains that the IPA’s assumptions, theories, and beliefs about how wholesale electric supply markets function should be clarified and vetted, before the agency sets out in the future to “augment the current resource markets by, for instance, seeking longer-term purchases or PPAs to incent development of generation” (IPA Draft Plan, p. 30) (or any other “extraordinary measures”).

Staff has no objections to this remainder of this section of the Draft Plan, including subsections 5.1 through 5.5.

**5.1 *North American Electric Reliability Corporation (“NERC”) Reliability Assessments***

**5.2 *MISO***

**5.3 *PJM***

**5.4 *Resource Adequacy Uncertainty and Environmental Regulation***

**5.5 *Overall Conclusions for Illinois***

**6.0 *Managing Supply Risks***

**6.1 *Market Conditions***

In this section, Staff believes the IPA could improve the plan through the provision of more thorough justifications for the assumptions described in Table 6.1, on page 43. For example, a complete explanation for the various emissions price assumptions shown in the last column of that table would be an improvement. Also, the last sentence of footnote 116 on page 44 appears to contradict Table 6.1’s base-case assumption that CO<sub>2</sub> would be priced at \$5/ton: “It seems likely that carbon will not be priced until 2015 given the time needed to implement rules and the likelihood that the economic situation will not improve in the coming year.”

In addition, Staff believes the IPA could improve the plan by showing the effect of the various assumptions in Table 6.1 on LMPs. This could be done simply by adding an appendix with a pair of tables (one for each hub) showing the monthly peak and off-peak LMPs for each of the eight scenarios.

## **6.2 Role and Risks of Long-Term Contracts vs. Short-Term Supply Within the Planning Horizon**

Staff has no objections to this section of the Draft Plan.

## **6.3 Load Balancing Market Risks**

For the sake of accuracy, Staff recommends the following modifications to the first paragraph of Section 6.3:

The supply portfolios of both Ameren and ComEd beginning with the 2013 delivery year consist of either standard 50 MW block products or the metered output of the renewable resources purchased in December 2010 under long-term 20-year contracts. On a real-time basis, however, the output of these contracts will be either less than or more than the actual load on the respective utility systems (as described in this Procurement Plan, it is almost universally more than actual load in the 2013/2014 delivery year). In order to ensure a match between supply and demand, ComEd transacts in the PJM day-ahead and real-time spot markets, while Ameren does the same within the MISO markets. The functioning of these processes is well-documented in prior procurement plans for both physically and financially-settled supply contracts. Due to the significant shifts in load away from both utilities due to municipal aggregation and individual customer choice, the mismatch between supply and demand has become significantly more pronounced. The utilities are in the position of potentially selling large quantities back to their RTOs at prices that are below the original purchase price (because market prices have fallen since the products were procured). This potential is particularly pronounced when it comes to the 2007-vintage large-volume energy contracts mentioned in subsection 3.3.1. For the most part, projected electric supply costs are recovered from eligible retail customers through a set of utility charges that are updated relatively infrequently (such as annually). However, unanticipated imbalances between costs and revenues are tracked and form the basis for monthly credits or surcharges to ratepayers' bills, as governed by a "Purchased Electricity Adjustment" ("PEA") factor. The net costs of these load balancing transactions are passed through to retail customers through a tracking rider mechanism known as the Purchase Energy Adjustment (PEA). The PEA has become quite pronounced, especially for ComEd, where a 3000 MW contract due to expire in May 2013 at significantly higher than current market prices and a more pronounced impact of load loss due to municipal aggregation have caused significant supply/demand and pricing mismatch.

As originally written, the above paragraph may leave the erroneous impression that only ComEd is subject to a legacy contract with a contract price that is significantly above the level of current market prices. In addition, it may leave the false impression that the PEA is the sole mechanism for recovering (or crediting) the net cost (or revenues) of hourly balancing and any financial losses (or gains) due to mismatches between hedged contract quantities and actual demand levels. Furthermore, the last sentence may be an overly simplified account of the dynamics involved with the PEA. Finally, it is simply unnecessary for the intricacies of the PEA to be explained and understood for purposes of procurement planning.

The Draft Plan's focus on the PEA continues in subsection 6.3.1; and therefore Staff recommends that the IPA consider revising the second-to-last paragraph of 6.3.1, as follows:

The combined effect of ~~C~~customer migration and falling market prices has had and continues to have a significant impact on the utilities' electric supply charges, including but not limited to the PEAs. ~~increases in~~ In particular, utility rates have increased relative to market prices and even higher than the prices that were locked in place years ago through long-term hedge contracts, as ~~both the magnitude and volatility of the PEA~~ since the utility customer base shrinks relative to the power supply procured under those long-term contracts. In February 2012 it appeared that ComEd's PEA could more than double in March (from 0.5 to 1.0 cents/kWh), which would have resulted in a 4% increase in overall household electric rates (to 13 cents per kWh). While the increase in PEA was voluntarily capped, the problem remains: how to cover previously committed power procurement costs with a shrinking customer base. The converse can also occur: if customers return to the utility because market prices are rising compared to the price of the utility portfolio, the utility will need to procure additional supply in a rising cost market.

In subsection 6.3.2, the IPA discusses "full requirements products." For the most part, Staff has no objection to the content of this subsection. However, there is a

statement in the second-to-last paragraph that is not accurate and should be eliminated. It is followed by a set of unanswered questions that can be easily answered. In particular, Staff refers to everything past the first sentence of this paragraph:

At this point in the evolution of the retail electric marketplace in Illinois, customer migration risk is extremely large and attempts to incorporate a full requirements product into the current pre-existing portfolio may be difficult without paying a large risk premium for the product. Furthermore, the full requirements proposition seems to require an all-or-nothing approach. For example, would a bidder be assuming only the risk associated with a slice or tranche of the utility's load, with the utility assuming the balancing risk for the portion of the load covered by the pre-existing standard products portfolio? How would that bidder's risk be separated from the risks associated with the standard products portion of the portfolio? Would specific customers be assigned to specific supply products?

Draft Plan, p. 53.

Simply put, the "full requirements proposition" does not require an "all-or-nothing approach." The utility can purchase multiple full requirements "tranches" (or slices) for anywhere from 1% to 100% of its **actual** variable load over a given time period (e.g., a year). Each winning bidder would assume only the responsibility and risk associated with the number of slices sold. This would include the responsibility to provide energy for that percentage of the load, and the risk that the percentage could represent either more or less megawatt-hours ("MWh") of energy than the supplier may have anticipated when bidding on the contract, and the risk that it may be less than anticipated if market prices fall or more than anticipated if market prices rise. That is exactly the same risk now being faced directly by the retail customers that remain on the utilities' bundled supply tariffs. The utility (ultimately, its ratepayers) would then continue to assume the balancing risk for the portion of the load that is not covered by full requirements tranches. The utility could rely, to some extent, on standard fixed-quantity forward

contracts block to hedge against month-to-month and/or year-to-year market price changes. However, whether that reliance is associated with 100% (as now) or some smaller percentage of forecasted demand, such hedges are still limited by the nature of the standard fixed quantity product. It would not be necessary to assign specific customers to specific supply products, as the IPA asks. Furthermore, the question of whether or not such an assignment would be desirable is equally valid in relation to standard fixed-quantity supply contracts. Finally, there is ample precedent for the utilities using full requirements contracts for combined slices of demand that are greater than 0% but less than 100%. During the period from June 2008 through May 2009, full-requirements contracts were used to supply roughly two-thirds of the actual load of ComEd and Ameren. During the period from June 2009 through May 2010, full-requirements contracts were used to supply roughly one-third of the actual load of ComEd and Ameren. Unequivocally, the “full requirements proposition” does not require an “all-or-nothing approach.” Due to the problems identified above with the quoted paragraph from page 53 of the Draft Plan, Staff recommends that the paragraph be deleted.

Staff also notes that, in the paragraph that begins subsection 6.3.2, the IPA states:

The Constellation and Boston Pacific July 13, 2011, process comments (at <http://www.icc.illinois.gov/downloads/public/Boston%20Pacific%20Reply%20Comments%20on%20the%202011%20RFPs.pdf> ) describe an analysis that could be undertaken to quantify the difference between full requirements benchmark prices and the actual costs incurred through the use of block purchases plus the daily PJM/MISO balancing markets.

Draft Plan, p. 52.

Staff believes the plan could be improved by the IPA indicating whether or not it has performed or intends to perform the analysis cited in the above-quoted sentence and, if not, why not.

#### ***6.4 Demand Response as a Risk Management Tool***

Staff has no objections to this section of the Draft Plan.

### **7.0 Resource Choices for the 2013 Procurement Plan**

#### ***7.1 Incremental Energy Efficiency***

As noted in Section 1.0, Staff is still reviewing the new and expanded energy efficiency programs that are presented in the Draft Plan. If, following that review, Staff concludes that these programs are likely to be cost-effective, Staff would support the IPA's recommendation that the Commission order the utilities to pursue the programs.

Furthermore, Staff agrees with the proposal raised by Ameren and mentioned in the Draft Plan, wherein the approved amount of funds estimated to be needed to acquire the approved additional MWh savings in Section 16-111.5B shall be recovered by the utilities through the existing energy efficiency cost recovery mechanisms (those associated with the Section 8-103 programs). (220 ILCS 5/16-111.5B(a)(6)) In effect, the Section 16-111.5B funds would be added to the utilities' existing Section 8-103 budgets, creating a combined portfolio (Sections 8-103 and 16-111.5B) budget. In addition, Staff is generally supportive of Ameren's second proposal: that the independent evaluators who assess achieved savings may perform a single assessment of the combined utility programs authorized through Sections 8-103 and 16-111.5B, provided the resources dedicated to evaluation do not exceed 3% of

portfolio resources (Sections 8-103 and 16-111.5B combined utility budget). (220 ILCS 5/8-103(f)(7); 220 ILCS 5/16-111.5B(a)(5))

However, Staff would be opposed to Ameren's third proposal to count the resulting savings from Section 16-111.5B programs towards the attainment of the utilities' Section 8-103 savings goals, unless those Section 8-103 savings goals are adjusted upward by the expected energy savings from the Section 16-111.5B programs. To be clear, Staff would support counting the resulting savings from Section 16-111.5B programs (measured at the customers' meter) towards the attainment of each utility's portion of the Section 8-103 savings goals (as those goals have been modified by the Commission as part of 8-103 plan proceedings), as long as those goals are further modified to account for the expected increase in energy savings from the Section 16-111.5B programs (i.e., the expected net energy savings from all customers eligible to participate in the incremental programs, regardless of their choice of retail electricity supplier).

It is clear from the Draft Plan that the IPA has not taken a position with respect to combining Section 16-111.5B program savings and Section 8-103 program savings, or whether or not the former should count toward Section 8-103 goals. Arguably, these are issues that should be addressed in the context of proceedings focusing on Section 8-103 (like the three-year energy efficiency plan proceedings). Hence, Staff does not recommend any changes to the plan in this regard.

In addition, Staff recommends the following modification to the first full paragraph on page 57 of the Draft Plan (citations omitted):

To prepare for the assessments, utilities are required to conduct an annual solicitation process to request proposals from third-party vendors, and

submit the results to the IPA as part of the assessment, including documentation of all bids received. Once presented with the utilities' assessments, including results of the Total Resource Cost ("TRC") test, the IPA in turn is required to "include" for Commission approval ~~all~~ energy efficiency programs with a TRC score above 1.

Draft Plan, p. 57.

Based on Staff's reading of 220 ILCS 5/16-111.5B(a)(4), the IPA is not required to include "all" cost effective programs in its annual procurement plans.

### **7.2 Full Requirements Supply**

Staff has no objections to this section of the Draft Plan.

### **7.3 Standard Market Products**

Staff has no objections to this section of the Draft Plan.

### **7.4 Ancillary Services and Capacity Products (Including Demand Response)**

In subsection 7.4.2, the IPA argues, among other things, that the IPA should conduct an RFP in the spring of 2013 solely to procure on behalf of Ameren 540 MW of Zonal Resource Credits ("ZRCs") for the June 2015 to May 2016 delivery period. Staff disagrees for the following reasons.

First, this would be the only capacity being procured through the RFP. Relative to previous procurements, the quantity of 540 MW is extremely small. In the spring of 2009, the IPA acquired a minimum of 3,600 MW and a maximum of 11,240 MW for the 12 months of the June 2009-May 2010 period, 6,450 MW to 9,330 MW for the months of June 2010-May 2011, and 5,140 MW to 7,310 MW for the June 2011-May 2012 period. In the spring of 2010, the analogous minimums and maximums for the three upcoming plan years were 5,380 to 12,380 MW, 4,840 to 7,890 MW, and 3,910 to 5,290

MW. In the spring of 2011, the IPA acquired capacity on behalf of Ameren for just the June 2011-May 2012 plan year, ranging from 2,590 to 7,820 MW. Finally, in the most recent capacity procurement by the IPA, in the spring of 2012, an average of 4,318 MW were acquired for June 2012-May 2013, 4,400 MW were acquired for June 2013-May 2014, and 3,360 MW were acquired for the June 2014-May 2015 delivery period. Thus, the cost of conducting these procurement events could be allocated over a significant amount of capacity purchases and thereby held to a more reasonable level.

Second, while the IPA expresses its unwillingness to rely solely on the MISO's prompt year capacity auctions, due to the relative immaturity of the MISO process, Staff notes that the 540 MW that the IPA wants to procure on behalf of Ameren is not needed until the *third* year of the planning horizon. Thus, the upcoming spring will not be the last chance for the IPA to conduct an RFP, instead of relying solely on the MISO auction.

Third, Staff has noticed that in every RFP with which the IPA has sought capacity for multiple planning years, the later years have always commanded significant premiums relative to the prompt year. In the spring 2009 RFP, July 2009, July 2010, and July 2011 Planning Resource Credits ("PRCs") cost, on average, \$4,316, \$4,868, and \$7,405, respectively. In the spring 2010 RFP, July 2010, July 2011, and July 2012 PRCs cost, on average, \$312, \$871, and \$2,346, respectively. In the spring 2012 RFP, ZRCs for the second and third years of the planning horizon cost, on average, \$3,698 and \$7,642, respectively.

Fourth, while the 540 MW of capacity sought amounts to 35% of the capacity projected to be needed for the July 2015-May 2016 period under Ameren's Base-Case

forecast, this forecast is only as good as the utility's projections of customer switching. Under Ameren's "Low-Case" forecast, 540 MW amounts not to 35%, but to 250% of the ZRCs that would be required. A main driver of these various forecasts is customer migration to alternative suppliers, and the IPA cites migration as a key driver of load forecast uncertainty. (Draft Plan, pp. 15-19) While Staff generally supports the IPA's focus on the Base-Case forecasts of the utilities, that focus should not prevent the IPA from analyzing the impact on ratepayers of actual demand levels falling below the base case due to migration or other factors. From Staff's review of the Draft Plan, it is not clear if such an analysis has taken place, particularly in the case of the IPA's decision to secure 540 MW of ZRCs in the spring of 2013 for year 3 of the planning horizon.

Based on the arguments above, Staff recommends that the IPA eliminate from the plan the procurement of ZRCs for the June 2015 to May 2016 delivery period, through an RFP held during the current planning cycle.

In all other respects, Staff has no objections to the content of Section 7.4.

### **7.5 *Clean Coal***

In Section 7.5 of the Draft Plan, the IPA discusses the FutureGen 2.0 "clean-coal" project. Attached to the Draft Plan is an Appendix IV, containing a draft sourcing agreement proposed by the FutureGen Industrial Alliance, Inc. for use with the FutureGen 2.0 project. According to the IPA:

This proposal captures comments and suggestions from a July 3, 2012 stakeholder meeting organized by the IPA to bring together representatives of the FutureGen Alliance, Ameren, ComEd and ARES, and subsequent discussions by the FutureGen Alliance and various potentially affected parties. The discussions were instrumental in redesigning a sourcing agreement that was initially drafted as a conventional unit contingent contract for physical delivery of a specific generator's output to specific counterparties with stable market shares. In

its current form, the sourcing agreement is based on physical delivery into MISO and financial settlement with counterparties, with a mechanism that recognizes a constantly shifting share of retail load among utilities and ARES and that is intended to provide a high degree of competitive neutrality. Discussions continue among the interested parties and a further-revised sourcing agreement may be presented for the Commission's consideration during the formal docketed proceeding.

Draft Plan, p. 74.

The IPA also notes that:

In order to approve this sourcing agreement and this specific resource in this Procurement Plan, the Commission must ensure the proposed resource is priced at or below a confidential price benchmark. [The footnote here cites 20 ILCS 3855/1-75(d)(5)] The IPA has engaged one of its Procurement Administrators, Levitan and Associates, to create a confidential benchmark for FutureGen 2.0. Levitan has been the procurement administrator for the prior Ameren procurements and has prepared the confidential benchmarks that the Commission has subsequently approved for those procurement events. The IPA proposes that during the pendency of the 2013 Procurement Plan Docket, the Procurement Administrator will submit a benchmark report for the FutureGen 2.0 project to the Commission under confidential seal for approval. [The footnote here states that "[t]he IPA defers to the Commission as to whether the Commission would prefer to approve the benchmark as part of the Procurement Plan approval proceeding, in a separate docket, or as a non-docketed matter similar to approval of other benchmarks."]

The IPA understands that the FutureGen Alliance will submit, during the pendency of the Procurement Plan Docket, information sufficient for the Commission to assess the prices buyers will see for the output of this project, which it then can compare to the confidential benchmark and other relevant information.

*Id.*, p. 75.

The IPA concludes by requesting "Commission approval of a final proposed sourcing agreement and inclusion of this resource within the context of approving the 2013 Procurement Plan."

The procurement plan originally submitted by the IPA last year, in Docket No. 11-0660, also contained a clean coal proposal. However, that proposal can be

distinguished from the present proposal in several respects. First, in Docket No. 11-0660, the IPA did not identify a specific clean coal project, such as FutureGen2.0. Rather, it proposed to conduct an RFP to solicit bids from potential clean-coal facility owners. Second, in Docket No. 11-0660, the IPA did not present a sourcing agreement for the Commission to approve, which appears to be the IPA's intent this year. Hence, it is fair to say that last year's clean coal proposal was less focused and less developed than the current proposal. The Commission rejected the inclusion of a clean coal solicitation in the IPA's 2012 plan, concluding:

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

Order, Docket No. 11-0660, December 21, 2011, p. 55.

Of particular note in the above conclusion is the last sentence: "In summary, the Commission finds that the IPA's alternative language set forth in its October 18, 2011 Response to Objections for Section 41 of the Plan is reasonable and is hereby adopted for inclusion in the Plan." That reasonable IPA-proposed language was:

Section 75 of the IPA Act includes a requirement that annual procurement plans include electricity generated by the initial clean coal facilities. Moreover, it is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities. Thus, the IPA may also propose in a procurement plan the procurement of electricity generated by a clean coal facility that does not qualify as the initial clean coal facility. **Such a proposal is, however, subject to the approval of the Illinois Commerce Commission under**

***the standards set forth in section 16-111.5(d)(4) of the PUA. That standard requires a demonstration that the proposed procurement will result in electric service that is the lowest total cost over time.***

The record is insufficient at this time to conclude that conducting a procurement event for a clean coal sourcing agreement would result in the lowest total cost over time. Therefore, the IPA is not proposing the procurement of electricity generated from clean coal facilities at this time.

IPA Response to Objections, Docket No. 11-0660, October 18, 2011, p. 8, shown without underlines and strikeouts, as it appears later, in the IPA's Final 2012 Power Procurement Plan, filed on February 17, 2012, on p. 60, emphasis added.

The current 2013 Draft Plan does not mention this language from either the Commission's December 21, 2011 Order or the IPA's final 2012 procurement plan. In its revised plan, the IPA should address whether the clean coal proposal currently in the Draft Plan will be subject, not only to a comparison to a cost-based benchmark (20 ILCS 3855/1-75(d)(5)), but also to the approval of the Commission under the standards set forth in Section 16-111.5(d)(4) of the PUA, which require a demonstration that the proposed procurement will "ensure adequate, reliable, efficient, and environmentally sustainable electric service at the lowest cost over time, taking into account any benefits of price stability" (20 ILCS 5/16-111.5(d)(4)).<sup>2</sup> Staff recommends that the IPA clarify in this year's plan whether or not it continues to hold this view and explain why it expects approval of a FutureGen2.0 sourcing agreement (similar to the one included in the Draft Plan) will contribute toward that statutory goal. In addition, the Draft Plan does not provide any discussion of the circumstances under which utilities and ARES are required to source electricity from a retrofit clean coal facility. This is an aspect of the plan that Staff recommends the IPA clarify, as well.

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<sup>2</sup> Also note that "[t]he Agency shall revise a procurement plan if the Commission determines that it does not meet the standards set forth in Section 16-111.5 of the Public Utilities Act" (20 ILCS 3855/1-75(f)).

Finally, Staff continues to study the specific terms and conditions within the draft sourcing agreement that was included with the Draft Plan. Staff will address specific sourcing agreement issues after the IPA files its revised plan with the Commission.

## **8.0 Renewable Resources Availability and Procurement Analysis**

### **8.1 Renewable Resource Budgets**

In this section, Staff recommends that the IPA address the following typographical corrections and clarifications.

First, on page 76, the IPA indicates that it:

... will release the blended average unit prices of the total wind and non-wind portfolio of purchases for each utility, i.e. the imputed average REC prices, to allow the Commission to consider the IPA's proposal on whether to procure additional renewable resources in this and subsequent Procurement Plans.

Draft Plan, p. 76.

Since the Commission is already privy to those imputed average REC prices, Staff recommends replacing the phrase, "to allow the Commission to consider the IPA's proposal," to the phrase, "to allow the public to understand the IPA's proposals."

Second, on page 77, the phrase, "there a quantity sub-targets," should be changed to "there are quantity sub-targets" (replacing the "a" with an "are").

Third, in order to avoid confusion, the word "benchmark" should be deleted in the following paragraph, as shown:

A recent market-based [benchmark](#) price for solar RECs can be found in the Ameren purchase of 2,188 solar PV RECs for delivery in the 2012/13 delivery year for \$80 per REC. In the February 2012 Rate Stability REC procurement, Ameren's purchase price for annual PV RECs for delivery over the 2013-2017 period ranged from about \$85-100 per REC. The maximum prices Ameren could pay fall well below the [benchmark](#) price for the 2014-15

and 2015-16 delivery years, casting doubt on the ability to achieve the solar and DG volume targets for those years

Draft Plan, p. 78.

The “benchmark” price referred to in the above paragraph is quite different than the confidential “benchmark” that is prescribed in 220 ILCS 5/16-111.5. Additionally, a period is missing at the end of that paragraph.

Further down on page 78, the Draft Plan states:

Again, it appears that a cost-effective solar PV procurement, which could include DG solar, may only be conducted for 2013-14 delivery, using prior procurements as a benchmark.

In this case, Staff recommends either changing the word, “benchmark,” to “reference point,” or modifying the sentence as follows:

Again, Realistically, based on experience from prior procurements, it appears that a cost-effective solar PV procurement, which could include DG solar, may only be conducted within budget only for 2013-14 delivery, ~~using prior procurements as a benchmark.~~

Draft Plan, p. 78, emphasis added.

Aside from the above typographical corrections and clarifications, Staff has some substantive concerns with Section 8.1, centering on the following paragraph:

The IPA proposes, upon approval of the 2013 Procurement Plan, to enter into discussions with the utilities and the counter-parties to the 2010 long-term energy and REC contracts to sort out a mechanism wherein any shortfall in the ability of the utility to purchase the REC portion of the output is made up for by the IPA’s RERF. As an example of how this might work, the utility might sell to the IPA at the imputed REC contract price any RECs that would cause the utility REC budget to be exceeded. The IPA would then retire those RECs. The RECs would have been purchased initially through the 2010 competitive procurement approved by the ICC. The IPA would set up any required accounts and processes at PJM and M-RETS that would facilitate the documented retirement of RECs.

Draft Plan, p. 82.

While identifying the likelihood that the utilities will be unable to purchase 100% of the RECs pursuant to the above-mentioned 20-year contracts, the Draft Plan also acknowledges that those contracts contain explicit provisions allowing for curtailment sufficient to assure that the rate caps (budget limits) would not be exceeded. (Draft Plan, p. 80) Although not specifically addressed by the Draft Plan, those contract provisions are consistent with Appendix K from Docket No. 09-0373, which was approved as part of the Commission's Order in that docket and was the basis for the 20-year energy and REC procurement contracts. In Appendix K there is a section addressing contract payment which specifically provides that "[u]tilities shall not be liable under the Long-Term PPA (or any related financial swap agreements) for any costs that cannot be recovered from customers through those pass-through tariffs." (Order, Docket No. 09-0373, Appendix K, p. 5)

While the Draft Plan at one point recognizes that the purchase by utilities under the December 2010 20-year contract could be curtailed, in certain parts it seems to suggest that its proposal is a bailout of a utility obligation. However, that is simply not the case given that the contracts entered into between the utilities and suppliers allowed for the purchases to be curtailed as required by the Commission's Order in Docket No. 09-0373 and consistent with Section 1-75(c)(2). (20 ILCS 3855/1-75(c)(2)) On the other hand, at least in the short run, "the imputed REC contract prices," at which the IPA plans to purchase RECs from the utilities or their current REC suppliers, may exceed (and are likely to exceed) the prices of RECs that could be purchased through a new competitive RFP for one-year unbundled REC contracts. Hence, at least in the short run, the IPA's plans may constitute a bailout of, if anyone, the suppliers holding those

20-year contracts. However, those imputed REC prices fall over time. Depending on the actual (as opposed to forecasted) path of electric energy prices over the next 19 years, it is even conceivable that, in the long-run, the total cost of these contracts could fall below the total cost of buying electricity at spot market prices. Staff does not contend that such a scenario is likely. However, if such a scenario were likely, then, in the long-run, the IPA's plan would be likely to help eligible retail customers, too. This is because the plan may help the utilities retain the 20-year contract suppliers, who, with each announced reduction in their annual contract quantities, have the options of terminating their agreements with the utility, accepting the lower contract quantity on an annual basis, or accepting the lower contract quantity for the life of the contract (or until reduced further). The Draft Plan is silent with respect to this aspect of the proposal, presumably because it was not analyzed by the IPA. In Staff's view, such considerations should be explored by the IPA, before it enters into discussions with the utilities and suppliers to sort out a mechanism wherein any shortfall in the ability of the utility to purchase the REC portion of the output is made up for by the IPA's RERF.

Notwithstanding the above concerns, and subject to some modifications, Staff does not oppose the IPA's attempt to address the issue of curtailed purchases under the 20-year energy and REC procurements. However, based upon these comments and concerns, Staff recommends the following changes to Section 8.1.3 of the Draft Plan:

### 8.1.3 Conclusions for 2013 Renewable Resource Procurement

\* \* \*

#### ***Use of the Alternate Compliance Payments by ARES to Supplement Utility RPS Budgets for Purposes of Performance Under the 2010 Long-Term Bundled Energy and REC Contracts***

The renewable energy obligation for ARES is measured as a percentage of the actual amount of metered electricity (megawatt-hours) supplied by the ARES in the compliance year. ARES must meet at least 50% of their renewable energy resource obligations through the Alternate Compliance Payment (ACP) mechanism.<sup>(fn 138)</sup> The remaining 50% of the obligation may be met with additional ACP payments, by procuring renewable energy, or by procuring RECs sufficient to comply with the RPS. ACPs are remitted by ARES directly to the ICC, and the ICC forwards that money to the Renewable Energy Resources Fund administered by the IPA for use in purchasing RECs. The IPA is directed to purchase renewable resources at a price not to exceed the winning bid prices for like resources under the IPA's procurements for electric utilities.<sup>(fn 139)</sup> The ACP rate, which is essentially the average price of RECs purchased for the utilities, fluctuates from year to year based on the results of IPA procurement events. Nevertheless, because the ACP is tied to the average prices for renewable resources purchased by the utilities, the mechanism allows for competitive neutrality with respect to RPS compliance costs passed through to all retail electric customers.

The IPA does not believe it requires Commission approval to spend the RERF in any fashion, either within or outside of a Commission-approved procurement plan. The IPA presents this proposal in the context of this Plan, however, so that the potentially [reduced Ameren and ComEd long-term REC procurements may be addressed.](#) ~~shortfall in the utility ability to compensate the long-term REC sellers may be settled.~~ The IPA is not a party to the contracts between the utilities and the generators under these contracts, nor does it wish to be. The IPA's sole obligation is to purchase RECs through competitive procurements that are similar in price and qualities to those procured by the utilities, and to then retire those RECs.

It makes sense that if the Ameren and ComEd long-term REC procurements are ~~being reduced~~ [becoming "stranded"](#), in large part because of customer load shifts to ARES, that the ARES RPS compliance payments made through the ACP mechanism be used to make up for the subsequent shortfalls in the utility RPS budgets caused by those load shifts. [Use of these funds for this purpose is consistent with the IPA's belief that ACP money is intended to aid RPS compliance on behalf of](#)

~~ARES customers. The IPA will be examining its options for spending the RERF funds, including but not necessarily limited to purchases of RECs that would otherwise have been purchased by Ameren and ComEd except for the spending constraint. On the other hand, the IPA has to consider that the ACP money is intended to aid RPS compliance on behalf of ARES customers, meaning that every dollar spent on prior purchases of renewable resources on behalf of eligible retail customers is a dollar not spent on procuring renewable resources on behalf of ARES customers.~~ The IPA will make a decision with regard to this balancing issue outside of the context of the Procurement Plan.

Beyond the changes, suggested above, Staff agrees with the content of Section 8.1, as well as the assessments and proposals set forth therein. For example, Staff supports:

- the IPA's decision to release the blended average unit prices of the total wind and non-wind portfolio of purchases for each utility, i.e., the imputed average REC prices;
- the IPA's proposal not to procure additional renewable energy resources for ComEd and Ameren at this time;
- the IPA's proposal that the utilities use revenues from the application of "alternative compliance payment" rates to hourly retail supply customers in order to offset any inability to take full delivery under the long-term 2010 bundled REC and energy contracts due to rate cap limits, and that the Commission allow any unneeded revenues from those sources to roll-over from year to year; and
- the IPA's stated intention to explore options for and the desirability of using revenues from the application of "alternative compliance payment" rates to alternative retail electric suppliers (which are deposited in a fund available to the IPA for purchasing RECs) in order to purchase RECs from Ameren

and/or ComEd or directly from REC suppliers, to the extent to which the utilities would otherwise be unable to take full delivery under the long-term 2010 bundled REC and energy contracts due to rate cap limits.

## **8.2 Other Renewable Resources - Distributed Generation**

The renewable portfolio standard section of the IPA Act (20 ILCS 3855/1-75(c)(1)) now requires the IPA to include purchases from “distributed renewable energy generation devices” in its plans. The IPA has made a significant start in designing a practical system for procuring RECs created by aggregations of “distributed renewable energy generation devices.” The IPA seeks the Commission’s approval only of the “general parameters” of the proposed system. The IPA notes:

Given the uncertainty around the projections and the availability of ACP funds to supplement the budgets, it is not clear when it may be economically feasible to actually begin a Distributed Generation program due to the potential effects on the requisite 5 (or more) year contracts. Rather than wait to approve such a program until it becomes crystal clear that the utilities can afford to include one in their portfolios, the IPA wishes to propose a program design for Commission approval in the 2013 Procurement Plan, for implementation at such time as the RPS budgets and available ACP funds allow.

For the most part, Staff agrees with the recommendations put forward by the IPA in this section of the Draft Plan. As noted below, there are just a few areas that Staff believes should be clarified.

First, when the IPA says “for implementation at such time as the RPS budgets and available ACP funds allow,” it is not clear if the IPA is contemplating such implementation to begin at the IPA’s discretion (i.e., when it makes the determination that the RPS budgets and available ACP funds allow) or only after the Commission finds that the RPS budgets and available ACP funds allow. Staff suspects it is the latter

case (which Staff would support), but Staff also recommends that the IPA clarify its intentions within the plan.

Second, in the IPA's description of the proposed system, it is unclear whether RECs created by distributed renewable energy generation devices within the service territory of one utility can be sold only to that utility, or also to the other utility. For instance, while it is clear that RECs from generators in ComEd's territory may be sold to ComEd, may they also be sold to Ameren? The governing statutes do not seem to speak to this issue. Staff believes the issue might best be addressed by the procurement administrators, in consultation with the procurement monitor, the utilities, and Staff. However, if the IPA has a different view of the matter, then it would be appropriate for the agency to include a discussion of the issue in the plan.

Third, the Draft Plan discusses purchasing RECs from two classes of aggregated generators: (1) those with a nameplate capacity of at least 25 kilowatts ("kW"); and (2) those less than 25 kW. Aggregators of the first class would compete in pay-as-bid procurements. Aggregators of the second class would be paid the average winning prices from the pay-as-bid procurements multiplied by scalars. The IPA hired its current procurement administrators to recommend appropriate scalars. As stated in the Draft Plan:

Their analyses are included in Appendix V. In fact, the independent analysis conducted by each Procurement Administrator concludes that an appropriate scalar to use for either the Ameren or ComEd DG programs is 1.25. The IPA concurs.

Draft Plan, p. 85.

However, the report prepared by NERA also indicated:

The scalar has been selected to err, if at all, on the high side given the legislative target that half of DG resources come from the under 25 kW segment. If the under 25 kW category develops very rapidly, it may indicate that the scalar is too high and would be in need of future adjustment downward. ... The scalar could be adjusted down in the next IPA plan if it is over-stimulating the market.<sup>3</sup>

Staff agrees with the thrust of NERA's comments and would recommend that, at some point, the scalar should be re-evaluated to determine if it is either too high or too low. Clearly, if it leads to more than 50% of the RECs coming from the under 25 kW generators, then a transition to a lower scalar may be appropriate.

However, there is another consideration. There may come a point when there is room in the budget to satisfy some or all of the overall distributed generation goal, but not enough room to satisfy the goal of obtaining 50% of the overall distributed generation RECs from the more expensive generators that are under 25 kW. In such an instance, it may be appropriate to transition to a scalar that is approximately equal to the expected level of highest bids accepted in the pay-as-bid procurements (the marginal winning bids). Staff admits fine-tuning of the scalar, as discussed above, may be impractical, so Staff merely raises the topic for the IPA to consider. Staff does not necessarily recommend that the issue be resolved at this time.

Fourth, the plan could be improved by clarifying whether or not the standard offer (for aggregators of the under-25 kW generators), would require a five-year contract (as required of the winning bidders in the pay-as-bid RFP for the aggregators of the larger generators). In addition, the IPA could clarify whether the standard offer price would

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<sup>3</sup> Draft Plan, Appendix V-2, "Scalar for Pricing of Systems Under 25 kW (ComEd Territory), Prepared for the Illinois Power Agency by NERA for Purposes of Recommending an Appropriate Scalar for Pricing Renewable Resources Procured Through a Standard Offer to Small (<25 kw) Distributed Generation Systems"

change for a supplier: (a) only with the execution a standard offer contract; or (b) each year there is a pay-as-bid RFP (i.e., the new perhaps annually-determined price would apply to all contracts, both old and new). Staff recommends that the IPA include a discussion of the issue in the plan.

### ***8.3 Load Forecast Impacts on Renewable Resource Procurement Recommendations***

Staff has no objections to this section of the Draft Plan.

## **9.0 Procurement Process Design**

Staff has no comment on this section of the Draft Plan, but will address process issues during plan implementation, to the extent consistent with Staff's role in the implementation process.

## **Appendices**

- I. Ameren Load Forecast***
- II. ComEd Load Forecast***
- III. Retrofit/Repowered Clean Coal Facility Description***
- IV. Clean Coal Sourcing Agreement***
- V. Distributed Generation Survey and Scalar Analysis***
- VI. Legislative Compliance Index***

## Conclusion

Staff respectfully requests that the Illinois Power Agency revise its Draft Plan consistent with Staff's Comments herein.

Respectfully submitted,

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