COMMENTS BY THE STAFF OF THE ILLINOIS COMMERCE COMMISSION ON THE ILLINOIS POWER AGENCY'S 2012 DRAFT POWER PROCUREMENT PLAN

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Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, respectfully submits these Comments on the 2012 Draft Power Procurement Plan to the Illinois Commerce Commission ("Draft Plan") circulated by the Illinois Power Agency ("IPA") on August 15, 2011, pursuant to Section 16-111.5 of the Public Utilities Act ("PUA"), 220 ILCS 5/1-101 *et seq*. 220 ILCS 5/16-111.5.

I. Introduction

The Draft Plan constitutes a blueprint for procuring electrical energy, renewable energy credits ("RECs"), and various other related commodities needed to comply with the PUA, as well as the Illinois Power Agency Act, 20 ILCS 3855/1-1 *et seq*. ("IPA Act"), and to provide power to eligible retail customers, namely certain residential and small to medium sized non-residential customers of Commonwealth Edison Company ("ComEd") and the Ameren Illinois Company ("AIC" or "Ameren"). Some parts of the Draft Plan contain errors, omissions, or other deficiencies, which are described below. Staff also has substantive additions and modifications to the plan.

II. The IPA's Proposed Purchases of Capacity for AIC during the Spring 2012 for Plan Years 2013-2014 and 2014-2015

The Draft Plan states:

> For planning years 2013 and 2014, the IPA proposes to procure 50% and 35% respectively of the annual Capacity based on MISO's anticipated change to an annual forward construct. The IPA notes that FERC has not ordered on the MISO proposal and it's possible that the MISO proposal may be modified or rejected outright. As a solution, the IPA proposes that the Commission approve the IPA proposal to pursue annual Capacity for 2013 and 2014. But the IPA also asks that the Commission acknowledge

> the dynamic nature of the MISO proposal and therefore authorize the IPA to make modifications to this plan as warranted during the 2012 procurement process after consultation with the Procurement Administrator, Procurement Monitor, ICC Staff and Ameren Illinois.[1]

Given the current state of flux acknowledged by the IPA, however, Staff sees no reason to use the spring 2012 procurements to secure capacity for AIC beyond the proximate 2012-2013 plan year. Furthermore, looking forward to plan years beginning on and after 2013, it is unclear why the IPA proposes that AIC continue to obtain capacity through IPA procurement events rather than through the forward capacity market that MISO has proposed to implement, which the IPA characterizes as "akin to structures in place in PJM and other eastern regional transmission organizations."[2] That is, while the Draft Plan (and all IPA plans, to date) have called for ComEd to satisfy capacity requirements through participation in the PJM forward capacity market, the IPA has apparently rejected, for reasons not stated, the approach for AIC in a MISO forward market similar to the PJM structure.

Staff recommends that the IPA modify the plan to include capacity purchases for AIC only for the June 2012-May 2013 plan year. Furthermore, moving forward, if the IPA is intent on rejecting an RTO-organized market mechanism for AIC that the IPA has already accepted for ComEd, the IPA should provide valid reasons for that change.

III. Clean Coal

The Draft Plan states:

> Section 75 of the IPA Act includes a requirement that annual procurement plans include electricity generated by 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.

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[1] Draft Plan, pp. 45-46.

[2] Draft Plan, p. 13.

> Consistent with the statute, and to further demonstrate the viability of coal and advance environmental protection goals, the Agency plans to seek proposals for both Utilities for up to 250 MW of electricity generated by advanced clean coal technologies that capture and sequester carbon dioxide emissions. The Agency will accept proposals from existing clean coal facilities, clean coal facilities that are under development, and qualifying coal-fired power plants previously owned by Illinois utilities that have been converted or will be converted into clean coal facilities. If a proposal is accepted and approved by the Commission, the project sponsor and both Utilities will enter into long-term (20 years or greater) sourcing agreements. The Agency will solicit proposals from entities that demonstrate that they have made significant progress to meeting a commercial in-service date of December 31, 2017 as measured by the following criteria prior to proposal submission.[3]

Staff recommends several modifications to this aspect of the plan.

First, while Section 75(d)(1) of the IPA Act provides that "procurement plans shall include electricity generated using clean coal,"[4] and proclaims the State's goal that "by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities,"[5] in Staff's opinion the Commission is not obligated to approve any purchases from clean coal facilities other than those associated with the "initial clean coal facility," as defined in Section 75(d)(3).[6] Furthermore, while Section 75(d)(2) of the IPA Act prohibits purchases of clean coal facility output beyond a level at which rates for eligible retail customers increase by more than certain prescribed percentages (similar to purchases of renewable energy resources), this does not mean that the Commission cannot set a more stringent standard (except in the case of the "initial clean coal facility"). Given the expense of generating electricity with clean coal technologies relative to that of natural gas technologies, it seems unlikely that a

[3] Draft Plan, p. 54.

[4] (20 ILCS 3855/1‑75(d)(1)).

[5] Id.

[6] (20 ILCS 3855/1‑75(d)(3)).

solicitation of proposals for 20-year contracts with a clean coal facility will be in the financial interest of Illinois consumers.

Second, although the Draft Plan is unclear on this point, Staff is concerned that the IPA intends to charge the utilities for the expenses associated with its solicitation of proposals for 20-year contracts with a clean coal facility. Staff is concerned because such a solicitation could be extremely costly as well as unlikely to result in a contract beneficial for Illinois consumers.

Third, Staff is concerned that the IPA will be over-extending itself by engaging in another potentially complicated procurement process at the same time that it is being required by law to expand its activities into arranging contracts between the State's gas utilities and both a "clean coal SNG brownfield facility"[7] and a "clean coal SNG facility."[8]

Therefore, Staff recommends the IPA eliminate this Clean Coal Energy proposal from the Plan.

IV. Existing Long-Term Renewable Energy Contracts

A. IPA proposal to ignore the contracts

The Draft Plan states that "the contract volumes attributable to Long-term Power Purchase Agreements entered into by AIC in December 2010 are not factored out of the projection [of net energy demand] as physical delivery of those contracted volumes are not guaranteed to the Utility (the electricity under the contracts will be delivered to the transmission system as it is generated)."[9] The Draft Plan makes essentially the same

[7] See Public Act 97-0096 of the 97th Illinois General Assembly.

[8] See Public Act 97-0239 of the 97th Illinois General Assembly.

[9] Draft Plan, p. 26.

statement with respect to ComEd.[10] In Staff's opinion, the IPA's decision to ignore the 20-year contracts entered into by the utilities last December is improper and contrary to the position the IPA took when it proposed the procurement of those contracts. The IPA's justification for ignoring the 20-year contracts seems to be based entirely on the notion that "those contracted volumes are not guaranteed to the Utility." First, that notion is incorrect. Second, even if it were correct, it would not justify ignoring the contracts.

B. Guarantees

With respect to the notion that "those contracted volumes are not guaranteed to the Utility," the IPA appears to neglect the fact that the 20-year renewable standard contracts suppliers entered into include explicit guarantees and strong incentives for suppliers to deliver. For example, in the section of the *Confirmation* called "Performance Guarantee," the contract with ComEd states:

> 1. Guarantee – Other than is provided herein, Seller commits and guarantees the delivery on an annual basis of the Annual Contract Quantity of Product. The Annual Contract Quantity applies to both the energy and the RECs. …
>
> * * *
>
> 4. Short-Fall – Energy
>
> (a) In the event that at the conclusion of any Delivery Year the Seller has delivered less than 90% of the Annual Contract Quantity of Energy for that Delivery Year (after taking into account any shortfalls or carryovers from the prior Delivery Year), the Buyer will compare the Fixed Price to the average Floating Price for the Delivery Year in which the short-fall occurred. If the average Floating Price is lower than the Fixed Price, the Seller will not be required to make any payment to the Buyer. If the average Floating Price is higher than the Fixed Price, the Seller will pay the Buyer the difference between the average Floating Price and the

[10] Draft Plan, p. 34.

Fixed Price, times a quantity that would bring the shortfall to within 10% of the Annual Contract Quantity. This amount will be due on the payment date for the first Calculation Period of the Delivery Year immediately following the Delivery Year in which the short-fall occurred. Upon delivery of this payment, if such payment is due, Seller will be deemed to have delivered 90% of the Annual Contract Quantity of Energy for that Delivery Year. Upon the failure to make a payment required herein, in addition to the rights and remedies provided in Paragraphs 6 and 8 of the Credit Support Annex and without further notice to the Seller or without any need to designate an Early Termination Date, Buyer shall have the right to liquidate any Posted Collateral supporting the Energy Value and use the proceeds to satisfy fully or partially the payment due hereunder. If (i) such Posted Collateral is inadequate and Seller fails to make such payment, in the case of the first such instance, within three (3) Local Business Days following notice from Buyer, or in the case of all other instances, within one (1) Local Business Day following notice from Buyer, or (ii) Seller fails to replenish any Posted Collateral pursuant to demand by Buyer for such Delivery Amount pursuant to Paragraph 4(b) of the Credit Support Annex, then Buyer shall have the right to declare an Event of Default without further notice to the Seller.

(b) In the event that the Seller delivers at least 90%, but less than 100% of the Annual Contract Quantity of Energy for any Delivery Year other than the final contract Delivery Year, the Seller is required to cure that deficiency in the following Delivery Year by producing and delivering additional Product from the Generating Unit (i.e. RECs plus the associated energy) in the next Delivery Year equal to the previous Delivery Year's short-fall. Buyer will either pay to (if a positive number) or receive from (if a negative number) the Seller for the short-fall amount the difference between the Fixed Price that is applicable the year delivery is due and the Floating Price that is applicable at the time of delivery.

(c) Within 40 days following the final Delivery Year of the contract, if the average Floating Price is higher than the Fixed Price, the Seller will pay the Buyer the difference between the average Floating Price and the Fixed Price for the final Delivery Year, times a quantity that would satisfy remaining Product deliveries required to fulfill Seller's delivery obligations under the contract

C. IPA's decision is inconsistent with its treatment in the current plan of forecasted supplies from qualifying facilities, and is contrary its own position in Docket 09-0373

Staff notes that the IPA's decision to ignore the expected output from the facilities associated with the 20-year renewable contracts is inconsistent with its decision to fully account for expected plan year output from qualifying facilities in the AIC service territory:

- QF – Qualifying Facilities. The Company must procure energy from any qualifying facility meeting the requirements of Rider QF. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.[11]

Table F of the Draft Plan shows these QF MWHs being subtracted from the load forecast to arrive at a net load forecast.[12] The fact that the IPA factors out forecasted QF volumes (which, unlike the long-run renewable contracts, are completely unguaranteed and unsecured), while failing to do so with the long-term renewable contract quantities, is inconsistent and illogical.

It is also noteworthy that the IPA's plan to ignore the December 2010 swap contracts for hedging purposes is a complete reversal of the IPA's position from the one it took in Docket 09-0373 (where the procurement of those contracts was proposed by the IPA and authorized by the Commission). In that proceeding, the IPA's plan stated:

> The IPA recommends issuing solicitations for longer term power purchase agreements (PPAs) with renewable energy providers. Long Term PPAs can serve as a hedge against potential cap and trade legislation that would serve as an additional tax on fossil fuel costs.[13]

Of course, a "hedge against potential cap and trade legislation that would serve as an additional tax on fossil fuel costs" is merely a less general way of referring to a hedge against future increases in energy prices.

[11] See Draft Plan, p. 27. The annual quantity of QF MWHs shown for plan year 2012 is about 20% less than the quantity of MWHs that Staff expects from the 20-year renewable contracts.

[12] The volumes shown in Table F for plan year 2012 (Ibid), are approximately twice the level of QF MWHs shown in last year's plan, for plan year 2011 (Draft Power Procurement Plan, August 16, 2010, pp. 25-26), all of which were subtracted from the load forecast before new hedge quantities were chosen.

[13] ICC Docket 09-0373, IPA Plan, September 30, 2009, p. 51. http://www.icc.illinois.gov/docket/files.aspx?no=09-0373&docId=141472

D. Comparison of the Hedging Value of the 20 Year Contracts and Other Contracts Relied Upon by the IPA for Hedging Purposes

It is important to understand that neither the 20-year variable-quantity contracts nor the IPA's fixed-quantity energy and energy swap contracts are used and useful for reliability reasons. Their *only* value and purpose is in establishing hedges to reduce customer exposure to unexpected future increases in spot prices. Indeed, if these contracts were being relied upon for physical supply reliability purposes (rather than hedging purposes), the 20-year variable-quantity contracts are at least contractually supported by hard assets (the suppliers' intermittent wind and solar generating facilities), while the IPA's fixed-quantity contracts are not contractually supported by *any* physical generating assets.

As energy price hedges, both the 20-year renewable contracts and the other contracts in the IPA plans include guarantees. However, even if there were no guarantees, it would still be in the suppliers' interest to perform under the 20-year renewable supply contracts, since that is the only way the suppliers get paid for providing RECs. Furthermore, the prices of the 20-year contracts are currently above expected market prices and hence can be expected to be "in the money" for the renewable suppliers. That is, those suppliers can expect to get a better price from these contracts than in the competitive energy market. Thus, strategic defaults would seem to be just as unlikely for the 20-year contracts (at least for the foreseeable future) as they would be for the IPA's other hedging instruments (which, in any event, entail mark-to-market collateralization).

On the other hand, it is true that the 20-year renewable contracts have no quantity requirements or guarantees for specific time periods shorter than one year, while the IPA's other hedging instruments specify quantities, by monthly on-peak and monthly off-peak periods. In hindsight, it would have been appropriate to at least ask suppliers to provide weather normalized monthly on-peak and off-peak forecasts of output. However, even without such forecasts obtained directly from the suppliers, the IPA could and should have developed its own forecasts. Such a forecast has been prepared by Staff and is included in Appendix A. Along with all other energy hedge contract quantities, such renewable supply forecast quantities could and should be subtracted from the expected demand levels in order to determine the quantity of additional hedges to purchase during the upcoming spring.

Admittedly, such forecasts, like many things in the Draft Plan, are subject to uncertainty. Consider the demand forecasts, for instance. In principle, there is no difference between the uncertainty in a renewable supply forecast and the uncertainty in a demand forecast. Recall that, for the June 2012 and May 2013 period, the Draft Plan calls for completing a 100% hedge relative to the ***base case*** demand forecast quantities. However, just as it is theoretically possible that the renewable suppliers will produce zero MWHs in each month between June 2012 and May 2013 (as the Draft Plan assumes), it is possible that consumers will demand twice the level of the base case forecast. After all, customers have provided neither the utilities nor the IPA with any "guarantees" that they will not begin consuming that much more electricity, which could occur if enough customers switched from delivery service to bundled service, enough customers replaced gas furnaces with electric heat pumps, an extreme heat wave descended on the Midwest leading to higher than expected air conditioner usage, a large number of qualifying facilities malfunctioned, etc. Indeed, the IPA has provided no evidence whatsoever that a doubling-of-demand scenario is any less likely than the IPA's assumed zero production scenario.

In any event, Staff maintains that neither of these extreme scenarios is realistic nor appropriate for purposes of setting up a reasonable hedge against future price increases. Even the less extreme, more realistic, "High-Case" demand forecasts included in the Draft Plan would constitute unreasonable targets for hedging purposes. For the ComEd forecast for August 2012, projected demand under the High-Case scenario is greater than 50% above demand under the Base-Case scenario. On average, for plan year 2012, projected demand under the High-Case is more than 25% higher than the Base-Case. Furthermore, the differences between the High- and the Base-Case projections increase moving from plan year 2012 to 2013 and from 2013 to 2014. However, to its credit, the IPA does not recommend increasing hedge ratios from 100% to 150% in August 2012, just because this High-Case scenario is possible. Instead, the IPA bases its recommended quantities to hedge on expected (Base-Case) demand. The IPA should use the same logic and approach with respect to the quantities expected from the 20-year renewable contracts. It is simply unrealistic to expect those quantities to be zero, or to make such an assumption for the purpose of price risk management.

E. The impact of the IPA's proposal to ignore the 20-Year contract volumes during plan years 2012 through 2014

Based on Staff's projections of expected output from the renewable facilities associated with the 20-year contracts, the IPA's plan leads to an increase in the purchase of new fixed-quantity hedges of approximately 4% of expected demand and hence, a *de facto* increase in the planned hedge ratio from a level of 1.00 to a level of

1.04 (on average). This is not a dramatic increase and does not pose a significant concern, in and of itself. The concern is that the IPA's proposal, if accepted, would set a precedent that could lead to significant over-hedging in future plans if the IPA were to include more renewable energy contracts with energy hedge features. For this reason, Staff urges the IPA to reassess its position on the hedging value of renewable energy contracts and to account for the expected level of renewable energy volumes in the plan.

V. Renewable Portfolio Standard

In its Draft Plan, the IPA specifically solicits input from interested parties on its recommendations concerning the Renewable Portfolio Standard ("RPS").[14] Staff responds to that request in this section.

A. The conservative budget proposal

The IPA proposes to "[e]stablish a conservative Renewable Resources Budget for 20 years." In general, Staff agrees with the IPA's proposal. However, there are certain aspects of this proposal that Staff finds objectionable. Specifically, Staff believes it is unnecessary to specify a conservative budget (subject to change in the future) for the proximate plan year (in this case 2012-2013). Rather, Staff recommends continuing the established practice of computing a definitive budget for the proximate plan year. Indeed, the Draft Plan includes just such a definitive budget in Tables V and W and X and Z for AIC and ComEd, respectively. As such, Staff concludes that the IPA intends for its proposal to apply to the 19 plan years following the proximate plan year. Also, IPA proposes to "[a]pply the confidential future price curve generated by the IPA

[14] Draft Plan, p. 49.

and submitted to the ICC to back out Long Term Power Purchase Agreements (LTPPA) cost obligations from the RRB to yield a Net Renewable Resources Budget (NRRB) for each of the future years."[15] Staff concurs in the use of that future price curve (developed in 2010), but, as argued in the next section, Staff believes that price curve should be made public rather than kept confidential. Furthermore, Staff recommends that the IPA add that it intends to incorporate similar procedures in the future, as necessary, to back out other multi-year renewable contracts that may be executed. In addition, the IPA proposes to "[f]actor each annual NRRB by 50% and solicit RECs bids for up to the 20 year horizon using the factored NRRB as a hard budget limit." Again, Staff recommends that the IPA employ this 50% factor to create its conservative budgets only for the 19 plan years following the proximate plan year, as discussed above.

B. The proposal to invite bids for periods between 1 and 20 years

The IPA proposes to invite bids for periods between 1 and 20 years.[16] With respect to this proposal, Staff believes the IPA should clarify whether it contemplates soliciting bids for different time periods: (a) within separate procurement events; or (b) within a single procurement event. If the latter, the IPA should also specify, at least in principle, how procurement administrators will be instructed to choose between bids with different time periods. It is not a trivial matter, as the following hypothetical examples show.

[15] Draft Plan, p. 50.

[16] *Ibid.*

Suppose the following bids are received:

Table 1

	Forward Contract Bids for RECs of Various Tenures					
PY	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Bid 6
2012	$39.75	$40.50	$39.50	$39.50	$39.75	$37.85
2013			$39.50	$39.50	$39.75	$37.85
2014			$39.50	$39.50	$39.75	$37.85
2015				$39.50	$39.75	$37.85
2016				$39.50	$39.75	$37.85
2017				$39.50	$39.75	$37.85
2018						$37.85
2019						$37.85
2020						$37.85
2021						$37.85
2022						$37.85
2023						$37.85
2024						$37.85
2025						$37.85
2026						$37.85
2027						$37.85
2028						$37.85
2029						$37.85
2030						$37.85
2031						$37.85

With the information in Table 1, it is easy to choose between Bid 1 and Bid 2, and to choose between Bid 4 and Bid 5. However, how do you choose between Bids 1, 3, 4, and 6, where you are comparing bids for contracts of different durations? In Staff's view, it would depend on expectations of future prices of RECs. For instance, to compare Bid 1 to Bid 3, you would need to have some expectations about how much you might spend on RECs if you waited another year or two. For instance, suppose that you expect the price of RECs at the start of plan year 2013 to be $39.75 and at the start of plan year 2014 to be $39.50. Thus, comparing Bid 1 to Bid 3 ***could*** be done as follows:

Table 2

	Bid 1		Bid 3
PY	Sure Thing	Expected Spot Price of RECs	Sure Thing
2012	$39.75		$39.50
2013		$39.75	$39.50
2014		$39.50	$39.50
Average	$39.67		$39.50

Here (in Table 2), Bid 3 price (a certain $39.50 for all three years) is less than the average of Bid 1 price for year 1 and the spot prices of RECs over the next two years. The choice appears easy, in this case, as well.

What about choosing between Bid 3 and Bid 4, which have exactly the same price, but for two different durations? Using the same approach used above, a comparison can be made as follows:

Table 3

	Bid 3		Bid 4
PY	Sure Thing	Expected Spot Price of RECs	Sure Thing
	$39.50		$39.50
	$39.50		$39.50
	$39.50		$39.50
		$39.25	$39.50
		$39.00	$39.50
		$38.75	$39.50
Average	$39.25		$39.50

However, such a comparison as shown in Table 3 hardly seems definitive for purposes of choosing between Bid 3 and Bid 4. Even though the average of the Bid 3 price (for the first three years) and expected spot prices (for the last three years) is less than the Bid 4 price, the latter is known for the entire period. Thus, there is a trade-off between lower expected cost and lower risk. The same trade-off could arise when comparing Bids 3 and 6 and Bids 4 to 6. Clearly, more information is needed to select the best bid, such as some indication of how much uncertainty there exists in our forecast of future REC prices. The same issue exists when comparing purchase power agreements of different durations (or even more complicated, when comparison REC-only contracts with contracts that bundle RECs with purchased power or other products).

If the IPA cannot clarify within the plan how it proposes to select winners among a pool of renewable energy products with varying durations, it should at least acknowledge that the complex problem is to be left entirely to the implementation phase of the plan (which is largely under the control of the IPA and its procurement administrators). In addition, the IPA should assure the Commission that the methodology, whether it is specified now or later, will be transparent to all participants, in order to preserve confidence that the Illinois procurement process is fair.

C. The solar and wind carve outs

The Draft Plan states that the IPA:

- Will "[c]onduct procurements that yield carve-out consistent contracts for solar and wind,"
- Will "[s]ort bids according to price and source (solar, wind, etc.)," and

- Will "[s]elect bids in a manner that yields at least the minimum carve out requirements are met when the [Long Term Power Purchase Agreements] volume[s] are added to the new REC volumes."[17]

Staff believes that the IPA should provide sufficient detail about how the above-summarized process will work, in practice. Furthermore, Staff notes that, in the 2010 procurement of the Long Term Power Purchase Agreements, the wind and solar carve-outs were implemented in the following manner (as described in "Appendix 5 – Evaluation Process" of the RFP issued by NERA):[18]

a. Bids will be adjusted to make them comparable across different types of renewable energy. The adjustments will be made using a resource-specific factor developed by the Procurement Administrator in consultation with the Illinois Power Agency, the Procurement Monitor, and the Staff of the Illinois Commerce Commission.

b. Adjusted Bids are stacked from lowest to highest until either the Target or the Budget is met. If the Budget is met first, the selection is complete. If the Target is met first:

    - bids that are not yet selected are placed in the Rejected Pool (R Pool);
    - the percentage of the wind target achieved is calculated;
    - the percentage of the PV target achieved to this point is calculated; and
    - the evaluation proceeds to the next step.

c. Wind resources in the R Pool are put in the R-W Pool and their adjusted bids are stacked from lowest to highest. PV resources in the R Pool are put in the R-PV Pool and their adjusted bids are stacked from lowest to highest. Replacements of non-wind and non-PV resources by wind or PV resources are made on the following basis. If the percentage achieved of the wind target is higher [lower] than the percentage of the PV target achieved to this point, then replace an other resource (non-wind and non-PV) with a PV resource [wind resource], starting with the other resource with the highest adjusted bid

[17] Draft Plan, p. 50.

[18] Available from http://www.comed-energyrfp.com/2010-RFP/docs/lt/Appendix_5_LT_Evaluation_Process_8-NOV-2010%20final.pdf as of 9/9/2011.

price and the PV resource [wind resource] with the lowest adjusted bid price, to the extent that such a replacement is possible without exceeding the budget and while still meeting the Target.

d. Resources from Illinois and its Adjoining States in the R Pool are put in the ILA Pool and their adjusted bids are stacked from lowest to highest. Replacements of resources from Other States by resources in Illinois and its Adjoining States are made on the following basis. Replace a resource of a given type (wind, PV, or other) from an Other State by a resource of the same type in the ILA Pool, starting with the Other State resource with the highest adjusted bid price and the Illinois-Adjoining resource with the lowest adjusted bid price, to the extent that such a replacement is possible without exceeding the budget and while still meeting the Target.

With respect to the solar and wind carve-outs, Staff requests that the IPA clarify the extent to which its current proposal is intended to be different than the process described above.

D. The in-state preference proposal

The Draft Plan states:

> The Procurement Administrators will be directed to continue to establish benchmark REC prices, and to reject bids priced above the benchmarks. The benchmarks shall be set at levels that consider relevant market prices ***and the economic development benefits of in-state resources***.

Draft Plan, p. 50. Staff objects to the IPA's intention to set the benchmarks at levels that consider "*economic development benefits of in-state resources.*" Such consideration is wholly inconsistent with the PUA's instructions for developing benchmarks, which are as follows:

> (3) Establishment of a market‑based price benchmark.
>
> As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference.

> The price benchmarks may also be adjusted to take into account differences between the information reflected in the underlying data sources and the specific products and procurement process being used to procure power for the Illinois utilities. The benchmarks shall be confidential but shall be provided to, and will be subject to Commission review and approval, prior to a procurement event.

220 ILCS 5/16-111.5(e)(3). These statutory instructions contain no language that the benchmarks should reflect economic development benefits of in-state resources. Indeed, the only places where the legislature chose to express a preference for in-state resources was in the context of renewable energy resources[19] and in the context of "clean coal facilities."[20] Even in the case of renewable energy, the statute's in-state preference expanded to include resources located in states that adjoin Illinois, as of 2011. In any event, the mechanisms authorized in Illinois law for enforcing these locational preferences are completely separate from the requirements for benchmark.

For all the above reasons, Staff recommends that the IPA modify the plan as follows:

> The Procurement Administrators will be directed to continue to establish benchmark REC prices, and to reject bids priced above the benchmarks. ~~The benchmarks shall be set at levels that consider relevant market prices and the economic development benefits of in-state resources.~~

[19] 20 ILCS 3855/1-75(c)(3).

[20] 20 ILCS 3855/1-75(d) provides for certain benefits to an "initial clean coal facility" and in the definition of "clean coal facility," 20 ILCS 3855/1-20 states, "All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content, unless the clean coal facility does not use gasification technology and was operating as a conventional coal-fired electric generating facility on June 1, 2009 (the effective date of Public Act 95-1027)." Since most Illinois coal matches these characteristics, Staff avers that these provisions of the 20 ILCS 3855/1-75(d) and 20 ILCS 3855/1-20 constitute a preference for Illinois resources. However, the statutory process for approving contracts between the utilities and the "initial clean coal facility" is clearly set apart from the IPA procurement process governed by 220 ILCS 5/16-111.5.

VI. The Plan Should Include a Provide for the Release of Certain Information Pertaining to the 2010 Procurement of Renewable Energy Resources Via 20-Year Contracts

Staff recommends that the IPA include in its 2012 Plan that certain information previously considered confidential by the Commission at the request of the IPA pertaining to the 2010 procurement of renewable energy resources via 20-year contracts will be released. In its 2009 procurement plan for plan years beginning June 2010, the IPA proposed and the Commission approved the procurement of renewable energy resources via long-term contracts, where the winning bidders would supply AIC and ComEd with a "product" that bundled RECs and financial energy swaps, where the quantities of the bundled product would be tied to the output of specific electric generating facilities during the nominal period June 2012 through May 2033 (20 plan years). (*See* Docket 09-0373, Order, December 28, 2009, pp. 39-120) A request for proposals ("RFP") and related documents were issued in the fall of 2010, and bids to supply this product were submitted and evaluated in December 2010. The results of the RFP were approved by the Commission on December 15, 2010 and posted on the Commission's web site. The posting included the names of the winning bidders and the following quantity and price summary:

	Total Quantity to be Supplied (MWH per Year)	Average Price* ($/MWH)
AIC	600,000	$50.44
ComEd	1,261,725	$55.18

Each winning bid was either a wind or a solar photovoltaic ("PV") resource physically located in the state of Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana, or Michigan.

* The Average Price is for the initial delivery year (June 2012-May 2013). Under the contracts signed, the price escalates by 2% annually throughout the remaining 19 years.

The information release did not include the specific quantities and average winning prices of wind RECs and the specific quantities and prices of solar RECs to be purchased, for fear that such product-specific information could indirectly reveal the winning bid prices of certain individual bidders, in potential violation of Section 16-111.5(h) of the Public Utilities Act.[21]

The information release also did not include the procurement administrators' breakdown of the prices into their energy swap components and their REC components. To perform that breakdown, consistent with the IPA's proposal and the Commission's Order, the procurement administrators had to construct a forward energy price curve extending through May 2033, using it as a proxy for the energy swap price component of the bundled product. The REC price component in any given year was computed simply as the difference between the winning bid price of the bundled product (escalated to that year) and the forward energy price for that year. The reason none of this information was released to the public in December 2010 is that in Docket 09-0373, the IPA proposed (and the Commission approved) maintaining as confidential the procurement administrators' forward energy price curve. The original rationale for maintaining confidentiality over the forward energy price curve was never articulated in

[21] Section 16-111.5(h) states:

> The names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event. The Commission, the procurement monitor, the procurement administrator, the Illinois Power Agency, and all participants in the procurement process ***shall maintain the confidentiality of all other supplier and bidding information*** in a manner consistent with all applicable laws, rules, regulations, and tariffs. ***Confidential information, including the confidential reports submitted by the procurement administrator and procurement monitor pursuant to subsection (f) of this Section, shall not be made publicly available and shall not be discoverable by any party in any proceeding, absent a compelling demonstration of need,*** nor shall those reports be admissible in any proceeding other than one for law enforcement purposes. (220 ILCS 5/16-111.5(h), emphasis added)

Docket 09-0373 (nor is it articulated in the current Draft Plan). Nevertheless, Staff did not oppose the IPA's proposal to keep the forward energy price curve confidential, since the information could conceivably have been construed by some bidders as being pertinent to the price benchmarks developed by the procurement administrators and employed to exclude bids above the benchmarks, or as being pertinent to Commission decisions to accept or reject bidding results. The possibility that bidders would attempt to draw such inferences, whether justified or not, and the possibility that this would influence bidding, with unknown consequences, was deemed by Staff to be a potential, albeit minor, concern. However, that concern is now moot until next spring's procurement events, at which point the forward price curve from December 2010 will be at least 14 months old, and quite stale.

Notwithstanding the above rationales for keeping confidential the product-specific (wind versus solar PV) price and quantity results and the procurement administrators' forward price curve, Staff believes this information should be released now.

The rationale for releasing the product-specific (wind versus solar PV) price and quantity results is that this information is pertinent to each of the next 20 annual IPA procurement plan proceedings. Interveners in procurement plan cases have a legitimate need for this information, which otherwise would be known only to ComEd, AIC, the IPA and the Commission. Without the product-specific quantity information, nobody, other than ComEd, AIC, the IPA and the Commission, will know the extent to which the wind and solar PV goals of the IPA Act are being satisfied. Without the product-specific price information, nobody, other than ComEd, AIC, the IPA and the Commission, will know the relative cost of wind and solar PV resources. While there is still a significant risk that such information will indirectly reveal to the public the winning bid prices of certain individual bidders, Staff believes this risk is outweighed by the need of intervenors and the public to know the extent to which the individual wind and solar PV goals of the IPA Act are being satisfied and at what cost. The Commission can and should find that there is a "compelling demonstration of need" to release the information, as authorized by Subsection 16-111.5(h) of the PUA.[22]

The rationale for releasing the forward energy price curve developed by the procurement administrators for the 2010 long-term renewable RFP is that without this information, intervenors will have no idea how much of the total REC spending limit has already been reached and how much more can be spent during upcoming procurements. Furthermore, each year the Commission must post an alternative compliance payment ("ACP") rate (for the State's renewable portfolio standard applicable to alternative retail electric suppliers), based on the utilities' expenditures on RECs. Hence, release of this ACP rate information will have the same effect as releasing the forward energy prices, one year at a time. Finally, starting with the 2012-2013 compliance period, and continuing for one additional compliance period, this ACP rate must exclude the impact of the solar PV requirement. Hence, not only will the forward energy prices be revealed, individual product prices will also be revealed, unless the method of computing the ACP during these two years is kept secret, as well. Since there is no statutory requirement to maintain confidentially over the forward energy price curve developed by the procurement administrators for the 2010 long-term renewable RFP, one need not cite Subsection 16-111.5(h). Nevertheless, the

[22] *Ibid*.

Commission can and should make a finding that there is a compelling need to release the information.

To summarize, for the above-stated reasons, Staff recommends that the IPA include in its Plan a provision indicating that it intends to release the following information during the procurement process:

- The expected aggregate imputed cost of RECs acquired through that procurement event, for each utility (ComEd and AIC); and
- The expected aggregate quantity of RECs acquired through that procurement event, for each utility and for each resource type (wind and solar PV); and
- The procurement administrators' energy market price forecast for the 20 years beginning June 2012, which in Docket 09-0373 the IPA proposed that the Commission keep confidential.

VII. Alternative Compliance Payment Rate Computation

Section 16-115D(d)(1) of the PUA states, inter alia:

> … For compliance years beginning prior to June 1, 2014, each alternative compliance payment rate shall be equal to the total amount of dollars that the utility contracted to spend on renewable resources, ***excepting the additional incremental cost attributable to solar resources***, for the compliance period divided by the forecasted load of eligible retail customers, at the customers' meters, as previously established in the Commission approved procurement plan for that compliance year. ...[23]

There are numerous ways that one might choose to compute "the total amount of dollars that the utility contracted to spend on renewable resources, ***excepting the additional incremental cost attributable to solar resources***."[24] Since the first step in

[23] (220 ILCS 5/16‑115D(d)(1)).

[24] Id.

establishing alternative compliance payment ("ACP") rates is the annual procurement plan, Staff believes this is the proper proceeding for the Commission to approve a method. Since the utilities' renewable energy portfolios included no solar resources prior to the plan year beginning June 2012, and since the "excepting" provision cited above expires June 2014, the approved method would be in effect only for the two plan years beginning June 2012 and June 2013.

Staff proposes that the IPA modify its plan to include a method, and Staff recommends that it be the following. First, the total MWHs of RECs being purchased for the compliance period and the total dollars contracted to be spent on those RECs should be summed separately for solar photovoltaic RECs and all other RECs ("non-solar RECs"). The average price of the selected non-solar RECs should be computed by dividing the dollars to be spent on the selected non-solar RECs by the total number of non-solar RECs under contract. This average price (which effectively excludes any incremental cost attributable to solar resources) should be multiplied by the total number of RECs purchased (both solar photovoltaic and non-solar). To obtain the alternative compliance payment rate, this product should be divided by the forecasted load of eligible retail customers, at the customers' meters. The proposed methodology is hopefully clarified through the following hypothetical example.

	MWH	Dollars	Dollar per MWH of RECs	Dollars per MWH of Projected Sales
PY 2012-2013 REC Goals and Spending Constraint	2,597,398	$56,559,464	$21.775	
PY 2012-2013 Projected Sales and Spending Constraint	26,206,576	$56,559,464		$2.158
PY 2012-2013 Max ACP Rate				**$2.158**
Solar PV RECs under contract:				
from Dec 2010 20-year contract RFP	28,000	$4,200,000	$150.000	
from spring 2012 RFP	0	$0	n/a	
Total Solar PV RECs	28,000	$4,200,000	$150.000	
Non-Solar RECs under contract:				
from Dec 2010 20-year contract RFP	1,200,000	$18,000,000	$15.000	
from spring 2012 RFP	1,369,398	$10,000,000	$7.302	
Total Non-Solar RECs	2,569,398	$28,000,000	$10.897	
Grand Total	2,597,398	$32,200,000	$12.397	
Total Non-Solar RECs Dollars per MWH of RECs x Grand Total MWHs of RECs		$28,305,130		
PY 2012-2013 Actual ACP Rate (Hypothetical)	26,206,576	$28,305,130		**$1.080**

VIII. Contingency Planning

The plan should address a greater number of contingencies and should unambiguously specify how the IPA, utilities, and/or procurement administrators shall react to such contingencies. Staff recommends changes to other contingencies as well.

A. Failure to execute contracts with procurement administrator by critical dates

The Draft Plan (like all previous IPA plans) includes a schedule for implementing the plan. The plan implicitly assumes that the IPA will follow this schedule. However, since its inception, the IPA has never successfully met its own implementation schedules. For example, as shown in the following schedule from last year's IPA plan, the IPA expected to have hired procurement monitors in November 2010, who were to have developed and released the RFPs for electricity and REC supplies before the end of February, and held all procurement events by the middle of April. In contrast to this reasonable schedule, procurement administrators were not hired until April 5, 2011 (more than 4 months behind schedule).

TABLE B: PROPOSED IPA PROCUREMENT EXECUTION SCHEDULE

Procurement Activities	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
1. Procurement Administrator RFQ Issued	X								
2. Procurement Administrator RFP issued		X							
3. Procurement Administrator Selected		X							
4. RFP and systems developed									
5. RFP Released					X				
6. Procurement Event Preparation									
7. Procurement Events									
8. Supply Contracts Executed									
9. Procured Products Delivery Begins									

Table reproduced from Docket 10-0563, IPA Plan, 9/29/2010, p. 12.

As the Commission's procurement monitor noted, during the annual informal hearing process,

> This left a very short timeframe, less than two months, to conduct all RFPs and to execute contracts with the winning suppliers in order to have delivery of the products begin by June 1, 2011. Furthermore, the delay exposed ratepayers to the risk of incurring significant MISO-related penalties in the event that Ameren's capacity RFP could not be held in time to be able to satisfy its obligations with MISO. Ameren faced a MISO-imposed hard deadline of May 1st by which it was obligated to

> present Planning Resource Credits (PRCs) to meet its resource adequacy requirements for the month of June 2011. … Given the lack of time and significant risks at stake, the IPA opted for issuing two separate capacity RFPs. The first RFP implemented a "simplified" process that would allow Ameren to procure the June 2011 PRCs by the May 1st deadline. The second RFP procured capacity for the remaining 11 months of the service year.[25]

The above experience (and the experience of all other IPA planning cycles, to date), lead Staff to two conclusions. While Staff recognizes that some delay may be out of the IPA's control, there may be actions that the IPA could take which would alleviate this problem. First, the IPA should start its hiring processes earlier than it has been doing. For instance, instead of beginning the process of hiring procurement administrators in October, it should start the process ***at least*** a month earlier, as Staff first recommended in 2009.[26] Second, the plan should be amended to set forth the actions that the utilities should take in case the IPA, for any reason, still fails to execute a contract with a procurement administrator by critical dates.

B. Portfolio rebalancing due to changes in demand forecast

In the section concerning the AIC portfolio design, the Draft Plan states,

> **Portfolio Rebalancing in the Event of Significant Shifts in Load.** The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. [footnote omitted] In the event that Ameren's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, Ameren shall promptly notify the IPA. The IPA will subsequently convene a meeting with Ameren, Commission, and the procurement administrator to determine whether it is appropriate to

[25] Comments on The 2011 Procurement Process Pursuant to Section 16-111.5(o) of the Public Utilities Act, Boston Pacific Company, Inc., June 22, 2011, pp. 3-4.

[26] Initial Comments In Response To The Public Notice Of Informal Hearing (Request For Comments) Concerning The Spring 2009 Electric Procurement Events, ICC Staff, June 1, 2009, pp. 2-3; Comments by the Staff of The Illinois Commerce Commission on the Illinois Power Agency's Draft Power Procurement Plan, September 16, 2009, pp. 14-15; Response and Objections to the Illinois Power Agency's Procurement Plan Filed September 30, 2009 by the Staff of the Illinois Commerce Commission, October 5, 2009, pp. 25-26.

> rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved. Over the term of this Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, a re-balancing of the portfolio may be warranted. Again, the IPA will work with Ameren, the Commission and procurement administrator to determine the appropriateness of rebalancing the portfolio.[27]

The same "portfolio rebalancing" provisions are repeated for ComEd nine pages later.[28] In both instances, these provisions are identical to those found in last year's IPA procurement plan.[29] However, during implementation of last year's plan, it became clear to Staff that these portfolio rebalancing provisions are too vague and should be modified to provide clearer direction when demand forecasts change.

First, the provision's reference to an "annual forecast" is vague. In the IPA plans, planned purchases and forecasts are broken down into 24 periods per year. Does "annual forecast" mean the sum of all 24 periods? That is, can rebalancing only occur if the sum of the 24 revised base case forecasts for the 24 periods falls below the sum of the 24 original low case forecasts for the 24 periods (or rises above the sum of the 24 original high case forecasts for the 24 periods)? In the alternative, is it sufficient if any one or more of the 24 periods' forecasts experience such a change? If it is the latter, then does the rebalancing only take place for those specific periods that breach the high and low thresholds, or should the entire portfolio be rebalanced?

For example, suppose that the forecast changes as follows for the following three on-peak monthly periods:

[27] Draft plan, p. 34.

[28] Draft plan, p. 43.

[29] ICC Docket 10-0563, IPA Plan, September 29, 2010, pp. 33 and 50.

	Original On-Peak Forecast			Revised On-Peak Forecast
	Low Case	Base Case	High Case	Base Case
June 2012	3,919	4,669	5,543	5,400
July 2013	3,910	5,385	6,818	6,800
August 2013	3,063	4,588	6,902	7,000

From the Draft Plan, it is unclear whether the purchase plan should be revised for all three months (since all three months forecasts have increased quite substantially) or just for the last month (because the last month is the only one where the revised base-case forecast is above the original high-case forecast).

Second, the provision's reference to "during the active delivery year" is also vague. Does this reference mean that no rebalancing can be done until after the delivery year has begun (i.e., after June 1), even if a revised forecast is available prior to the spring procurement event? A more cost-effective approach would be to avoid an additional procurement event. Similarly, there is a reference to "the term of this Plan," which could mean anything from "the active delivery year" to the five-year time horizon represented in the Draft Plan's Graphs 2 through 5.

Third, it is unclear if the provision's reference to "Commission" is a reference to the five Commissioners entering an order or to the Staff of the Commission acting independently of the Commissioners? If it is the former, what would it mean for the IPA to "convene a meeting with … the Commission…"?

C. Default on REC contracts (or the REC component of the 20-year renewable energy contracts)

Last year, the Commission stated:

> Page 4 of the Plan discusses renewable energy resources. As an initial matter, the Commission disagrees with ComEd's interpretation of the IPA Act that there is no need for a utility to replace short-term RECs in the event that a supplier fails to deliver the contracted amount. Such an

interpretation conflicts with the underlying intent of the statute that RECs actually be purchased and possession taken by the Illinois utility. Failure to deliver by a supplier does not absolve a utility of its RPS obligations when alternatives exist.[30]

In addition, if a new RFP must be issued, the Commission considers it appropriate for any replacement short-term RECs to be procured by the IPA. The IPA's contingency plan for supplier defaults exceeding 5% of the RECs secured for the Plan year, however, is perhaps too vague. Specifically, the proposal fails to deal with several issues of timing. For instance, at what point in time does the IPA plan to hold these procurement events (multiple times per year, once per year, at the next regularly scheduled REC procurement event)? What vintage RECs would be procured? If the default is not even detected until after the relevant Plan year, will the IPA try to procure RECs under the previous year Plan or the current Plan? Finally, if the contract defaulted upon was for both energy and RECs, should the IPA seek to replace both or just the RECs. To what extent (if any) should options be written into contracts to allow for non-faulting suppliers to make up for defaulting suppliers' quantities? Because the IPA's contingency plan fails to address these questions (and perhaps others that have not occurred to the Commission), the Commission is reluctant to approve the IPA's contingency plan for replacing RECs. Furthermore, the Commission sees no urgency to deal with this issue. There is no evidence that there have been any REC supply deficiencies due to supplier defaults, to date. ***Hence, rather than approve the IPA's contingency plan, the Commission suggests that the IPA develop a more detailed proposal and include it with next year's procurement Plan.***[31]

As far as Staff can discern, the Commission's suggestion went unheeded by the IPA; the Draft Plan appears to completely lack a plan for the contingency that suppliers might default on REC contracts. Thus, Staff proposes the following addition to the plan.

<u>Material Instances of Supplier Default on Renewable Energy Contracts</u>

<u>With respect to any contract entered into by Ameren [ComEd] as a result of an IPA procurement process, if Ameren's [ComEd's] counterparty to the contract defaults, and such default results in a reduction in the number of renewable energy credits ("RECs") retired on the utility's behalf for any given plan year (ending May 31), the IPA shall add the shortfall of RECs to</u>

[30] ICC Docket 10-0563, Order, December 21, 2010, p. 94.

[31] ICC Docket 10-0563, Order, December 21, 2010, pp. 94-95 (emphasis added).

the quantity of RECs to purchase through RFPs issued for subsequent plan years. Any dollar amounts that were not spent due to the default, plus any additional collateral retained by Ameren [ComEd] due to the default, shall be added to the REC budgets for those subsequent plan years. If possible, the purchase of the replacement RECs shall be reflected in the subsequent procurement plan(s). However, even if not explicitly reflected in a procurement plan, the IPA may include in an RFP the purchase of replacement RECs associated with recent defaults, if such inclusion is deemed acceptable, unanimously by the procurement administrator, the procurement monitor, and Ameren [ComEd].

The IPA recognizes that, except in the case of defaults on long-term contracts, it will not be feasible to replace RECs with those of identical vintage. For example, if sometime in December 2012, it becomes clear to the IPA that a supplier will fail to supply all of the June 2012-May 2013 vintage RECs that the latter agreed to supply, the IPA would be hard pressed to hold a special RFP before the end of the vintage year. Furthermore, even when possible, the expense of holding a special RFP for what might be a small quantity of replacement RECs would be high. Of course, if the Commission concludes that separate procurements for replacement RECs are necessary, the IPA will comply. However, in the IPA's view, it would be preferable to absorb each replacement REC requirement and budget into the REC requirement and budget for one or more later vintage periods. Note that, in the case of defaults on long-term contracts, this mismatch of the vintages would only exist for the first year.

IX. Corrections

A. Use of the term "Commission"

The Draft Plan uses the capitalized term, "Commission," to refer to two different entities. Most prominently, it is used to refer to the Illinois Commerce Commission.[32] However, it is also used in reference to the Federal Energy Regulatory Commission.[33] To avoid confusion, Staff recommends that the plan be modified to use the acronym "FERC" in reference to the Federal Energy Regulatory Commission, reserving the term, "Commission," for the Illinois Commerce Commission. In addition, Staff recommends

[32] See Draft Plan, pp. 1-6.

[33] See Draft Plan, pp. 11-13.

that the above-described usage of these terms be made clear at the initial references to the Federal Energy Regulatory Commission and the Illinois Commerce Commission.[34]

B. Use of the term "dollar-cost averaging"

The Draft Plan states:

> Graphs 4 and 5 represent how the Plan anticipates securing load for Eligible Retail Customers by laddering in purchases so that no one month or season is purchased all at one time. By dollar-cost averaging in this manner, the IPA mitigates risk to ComEd's Eligible Retail Customers.[35]

This is admittedly a minor point, but the term "dollar-cost averaging" is inapt in this context. Dollar-cost averaging refers to the practice of regularly investing over time equal ***dollar amounts in an asset*** or a portfolio of assets. In contrast, the IPA's plans have always centered on securing specific ***quantities of assets***. Thus, the IPA's strategy is not dollar-cost-averaging as stated on page 41 of the Draft Plan. Whether it is particularly analogous to dollar-cost averaging as stated on page 25 of the Draft Plan is debatable. The Staff recommends deleting from the plan those two sentences that contain the term "dollar-cost averaging."

C. Various references to previous procurement cycles

1. In the first paragraph on page 2, the Draft Plan refers to "2011-2012 planning year," which Staff assumes the IPA meant to be the 2012-2013 planning year. Thus Staff recommends the following change:

> In the ~~2011-~~2012-2013 planning year, the IPA portfolios will supply approximately 40 million MWH to almost 4.5 million "eligible customers" of ComEd and Ameren.

[34] Page 1 for the Illinois Commerce Commission ("Commission") and page 11 for the Federal Energy Regulatory Commission ("FERC").

[35] Draft Plan, p. 41.

2. Toward the bottom of page 7, a numbered paragraph 6 reads as follows:

> **Procured Products Delivery Begins.** Supply contracts secured through the spring 2011 procurement events will commence in June of 2011 (some contracts may be effective at a later date). These procured volumes will be in addition to those electricity supplies already secured via legacy contract sources from the swap contracts resulting from the 2007 rate settlement agreement, and the 2010 IPA procurement cycle.

The above paragraph contains several errors. First, the two references to 2011 both should be to 2012. The reference to the 2010 IPA procurement cycle should be to the 2010 and 2011 IPA procurement cycles. In addition, certain phrasing is unnecessarily vague and imprecise. For example, it intertwines the dates upon which contracts are executed and dates upon which products are physically delivered or financially settled. It also intertwines the concepts of physical delivery and financial settlement. Finally, the term “2007 rate settlement agreement” is misleading (suggesting a settlement agreement that was part of a Commission proceeding) and lacks foundation. Therefore, Staff recommends rewording the paragraph to correct the errors and clarify the facts:

> **Procured Products Delivery Begins.** Physical delivery under the ~~S~~supply contracts secured through the spring 2012~~1~~ procurement events will commence in June of 2012~~1~~ (later, in the case of some contracts~~ may be effective at a later date~~). These new contracts ~~procured volumes~~ will ~~be in addition to those electricity supplies already secured~~ supplement financial and physical hedges already in place via legacy contracts. These legacy contracts include the contracts that resulted from the 2010 and 2011 IPA procurement cycles, as well as certain financial swap contracts alluded to within the PUA[36] and executed in 2007 contemporaneously with passage of the IPA Act. ~~sources from the swap contracts resulting from the 2007 rate settlement agreement, and the 2010 IPA procurement cycle.~~

[36] See Subsection (k) of Section 111.5 of the Public Utilities Act (220 ILCS 5/16-111.5(k)), added by Public Act 095-0481, which also created the IPA Act. These swap contracts are between the utilities and their affiliates and did not require Commission approval. They predate the first IPA plan and were not the result of a Commission approved competitive procurement process.

3. On page 38, in reference to the ComEd portfolio, the Draft Plan states, "Second, certain fixed price physical supply contracts were secured through the 2010 procurement process." However, none of those contracts included delivery periods after February 2012. That is, they were not for the upcoming June 2012 plan year or any plan years beyond 2012. In 2011, on the other hand, the IPA procurement process resulted in the acquisition of contracts with delivery periods spanning the period June 2012 through May 2014. Hence, the reference to 2010 in the above-cited excerpt from page 38 should be changed to 2011, as follows:

> Second, certain fixed price physical supply contracts were secured through the 2011~~0~~ procurement process.

4. On page 41 of the Draft Plan, the legend for Graph 4 appears to be mislabeled. Less significantly, the vertical axis lacks a title (such as "MW"), and the horizontal axis lacks dates. As for the legend, it appears that all the labels that include a year are off by either one or two years:

- "Off-Peak 2009 Procurement" should instead read "Off-Peak 2011 Procurement"
- "Off-Peak 2010 Procurement" should instead read "Off-Peak 2012 Procurement"
- "Off-Peak 2011 Procurement" should instead read "Off-Peak 2013 Procurement"
- "Off-Peak 2013 Procurement" should instead read "Off-Peak 2014 Procurement"
- The first "Off-Peak 2014 Procurement" (orange) should instead read "Off-Peak 2015 Procurement"
- The second" Off-Peak 2014 Procurement" (light blue) should instead read "Off-Peak 2016 Procurement"

For partial confirmation of the above (for the first two years), see the Draft Plan's Table M on page 40. In addition, Staff suggests that the label, "Off-Peak Swap Volumes," could be renamed "Off-Peak 2007 Swap Volumes," for slightly greater clarity and consistency with the rest of the legend's labels. Similarly, in Table M on page 40, Staff recommends replacing "Swap Volumes (MW)" with "2007 Swap Volumes (MW)."

On page 42 of the Draft Plan, the legend for Graph 5 also appears to be mislabeled, and, less significantly, the vertical axis lacks a title (such as "MW"), and the horizontal axis lacks dates. As for the legend, the following corrections should be made:

- "Peak 2009 Procurement" should instead read Peak 2007 Swap Volumes." Similarly, Table L on page 39 also could replace "Swap Volumes (MW)" with "2007 Swap Volumes (MW)."
- "Peak 2010 Procurement" should instead read "Peak 2011 Procurement."
- "Peak 2011 Procurement" should instead read "Peak 2012 Procurement."
- "Peak 2012 Procurement" should instead read "Peak 2013 Procurement."
- "Peak 2013 Procurement" should instead read "Peak 2014 Procurement."
- The first "Peak 2014 Procurement" (orange) should instead read "Peak 2015 Procurement."
- The second" Peak 2014 Procurement" (light blue) should instead read "Peak 2016 Procurement."

For partial confirmation of the above, see the Draft Plan's Table L on page 39.

The analogous graphs for the AIC portfolio display a different type of problem. Graph 2 on page 32 of the Draft Plan shows the off-peak contract quantities that have been secured or are tentatively planned to be secured between spring 2012 and spring 2016. However, whereas the legend in the analogous graph for ComEd (Graph 4) uses the convention "Off-Peak YYYY Procurement" (where YYYY refers to the year of the procurement event), the legend in Graph 2 for AIC uses the following two conventions: "YYYY Contract Volumes (MW)" and "Targeted Contract Volumes YYYY-ZZZZ (MW)" (where YYYY refers to the year of the procurement event and ZZZZ refers to the following year). Neither of these two alternative conventions used for the AIC graphs is as clear or informative as the convention used for the ComEd graphs. Specifically, the ComEd version makes it clear that the labels are referring to procurement events taking place within the year listed. Thus, Staff recommends that the IPA modify the AIC graphs (Graph 2 and Graph 3) to be consistent with the ComEd graphs (Graph 4 and Graph 5). In addition, in all four graphs, Staff recommends titling the vertical axis with "MW."

5. The last sentence on page 50 of the Draft Plan refers to three planning years, which are purportedly included in Table U on page 51. However, Table U actually lists five planning years. Thus, the last sentence on page 50 should be amended as follows:

> Table U below presents the Annual Volume Targets resulting from the application of the statute's standards to the Ameren portfolio for planning years 2008-2009, 2009-2010, ~~and~~ 2010-2011, 2011-2012, and 2012-2013.

6. Table P on page 46 of the Draft Plan includes columns labeled "2009 Purchase," "2010 Purchase," and "2011 Purchase," which should be changed to "2010 Purchase," 2011 Purchase," and 2012 Purchase," respectively.

D. Internal reference errors

On page 51 of the Draft Plan, a reference to Table X should be a reference to Table W, as follows:

> Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables V and ~~X~~ W below presents the Annual

> Renewable Energy Resource Budgets resulting from the application of the statute's standards to the Ameren portfolio for planning year 2012-2013.

X. Risk Discussion on pages 8-20

The Draft Plan's discussion of risk contains several analytical and rhetorical deficiencies. A sample of these are discussed in this subsection. Since they do not have a direct bearing on the substantive features of the plan, Staff has not provided substitute language, but urges the IPA to consider this critique when it prepares future plans.

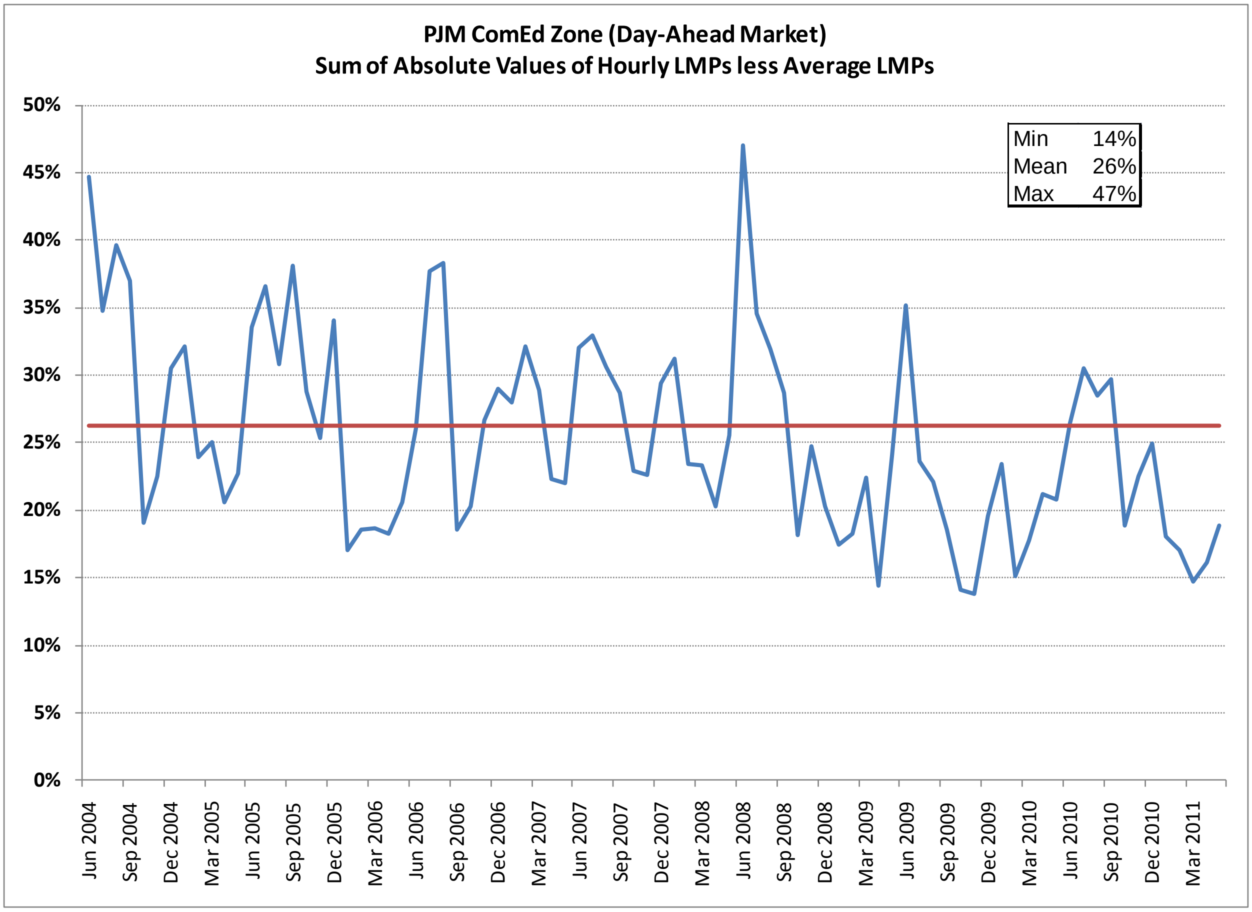
First, under multiple sub-headings, the Draft Plan discusses closely related and intertwined issues, or even the same issues. The plan could improve upon the structure of this risk discussion to draw out the inter-relationships between issues and to eliminate redundancy. For example, the discussions of "short-term clearing risk" (p. 8) and "weather patterns" (pp. 10-11) seem to be very closely related.

Second, not all of the issues discussed in this section are about "risk" or "uncertainty," but are about expected increases in costs. The discussion could be improved by clearly distinguishing between these two concepts. For example, in the discussion of "short-term clearing risk," the draft plan fails to acknowledge that, in addition to being a risk, is also an unavoidable consequence of hedging energy costs with fixed quantity contracts rather than flexible percentage-of-load style contracts. Furthermore, the assertion that "Short-term risks are largely mitigated through the use of load averaging and securing monthly contracts against those load averages" is not supported in the Draft Plan; and, in fact, is contrary to Staff's analysis of the issue. Indeed, "load averaging" is the ***cause*** of what the IPA calls "short-term clearing risk" rather than a mitigating factor. However, it is true that utilizing monthly rather than annual averages in setting these hedges reduces the extent of expected deviations from the hedged quantities, and utilizing on-peak and off-peak averages rather than around-the-clock averages reduces those expected deviations somewhat more. For example, using the current forecasts, over the 5-year planning horizon:

- The expected deviations of hourly load from the annual averages sum to 23% of total load for Ameren and 20% for ComEd.
- The expected deviations of hourly load from the monthly/annual averages sum to 18% of total load for Ameren and 14% for ComEd (an improvement of 5-6%, respectively).
- The expected deviations of hourly load from the monthly/annual on-peak/off-peak averages sum to 16% of total load for Ameren and 12% for ComEd (an additional improvement of 2%).

These remaining deviations of hourly loads from their monthly/annual on-peak/off-peak averages is important because, as seen in the following graph, hourly electricity ***prices***[37] also deviate significantly from their monthly/annual on-peak/off-peak averages, and the IPA's hedge strategy only covers expected average quantities and average prices.

[37] The prices used in the graph are Locational Marginal Prices ("LMPs") for the ComEd Zone in the PJM Day-Ahead energy market.



Since the hourly loads of eligible retail customers tend to be higher than average in hours when prices are higher than average (and hourly loads of eligible retail customers tend to be lower than average in hours when prices are lower than average), these deviations from average tend to increase total costs above the IPA hedged level. Over the last three plan years, the average impact for ComEd customers has been an increase in energy costs of about 3% for on-peak hedges and 7% for off-peak hedges. The maximum impact in any one month was about 9% on-peak and 26% off-peak. In addition, there is still a risk that the impact will be greater in the future. Notwithstanding the above-described weaknesses in the IPA's hedging strategy, Staff is not recommending any fundamental changes to it. However, Staff believes that the IPA should neither play down weaknesses nor exaggerate strengths when presenting procurement plans to the Commission.

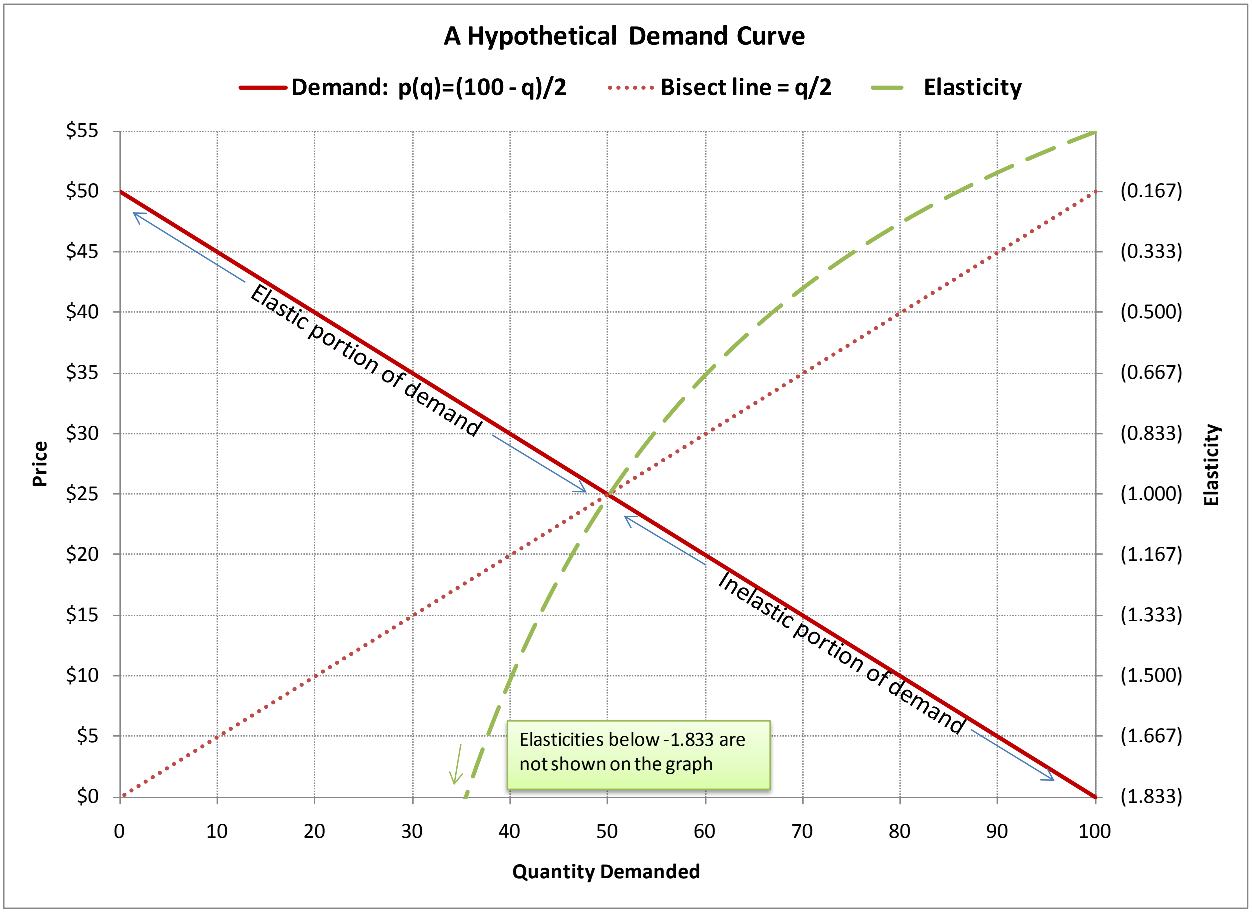
Third, in the discussion of "load uncertainty," the draft plan asserts that such uncertainty is due, among other things, "to [price] inelasticity of demand among many portfolio participants."[38] However, this is simply incorrect. Electricity demand uncertainty has little to do with the elasticity of electricity demand with respect to the electricity price. Furthermore, to the extent to which they are related, it would be more accurate to say that load uncertainty (in percentage terms) tends to be greater when demand is elastic than when it is inelastic, as explained below.

By definition, the elasticity of demand with respect to price is equal to the percentage change in the quantity demanded divided by the percentage change in price. Also by definition, demand is called:

- "Perfectly inelastic" when the elasticity is zero, which means that price has no affect on the level of demand;
- "Inelastic" when the elasticity is greater than -1 (or when the absolute value of this measure is less than +1);
- "Elastic" when the elasticity is computed to be less than -1 (or when the absolute value of this measure exceeds +1); and
- "Perfectly elastic" when the elasticity is $-\infty$ (a concept that is usually used to characterize the demand faced by a single firm in a perfectly competitive market, so that any increase in price above the market price leads to a complete loss of all demand).

[38] From the draft plan's discussion, it is clear that it is referring specifically to ***price*** elasticity.

Since the level of future electricity prices is subject to uncertainty, so is the future quantity of electricity demanded, except in the special case where demand is perfectly inelastic. In that case, if there were no other factors influencing the demand for electricity, there would be no load uncertainty. Aside from that special case, as demand becomes more elastic, the ability to predict loads starts becoming more and more slave to uncertainty over future price levels. As a general statement, the validity of this last statement depends on load uncertainty being expressed in percentage terms. The situation is not as clear-cut when demand uncertainty is expressed in MWHs. For example, consider the hypothetical demand curve shown in the following graph.



With such a demand curve (i.e., one that can be depicted as a straight downward-sloping line), demand is elastic everywhere to the left of the line's center and is inelastic everywhere to the right of the line's center). Consistent with the conclusion of the previous paragraph, on the left-hand side, changes in price lead to larger percentage changes in the quantity demanded, while, on the right-hand side, changes in price lead to smaller percentage changes in the quantity demanded (in absolute value terms). However, for any given change in the actual level of the price (in dollars per unit), the actual change in quantity (e.g., MWHs) are the same throughout the demand curve. Hence, in this case, when we use actual level changes rather than percentage changes, uncertainty over price leads to the same level of load uncertainty, regardless of elasticity. Thus, in this case, too, the Draft Plan cannot correctly state that load uncertainty is due to the inelasticity of demand. While there may be other scenarios where the Draft Plan's statement makes sense, the Draft Plan does not show that such a scenario exists and is relevant to the plan.

Fourth, also in the section on "load uncertainty," the Draft Plan states,

> Consumption by bundled service customers is relatively inelastic, meaning that consumption does not diminish significantly when prices are high. This is due in large part to current tariff structures that do not expose customers to price variance. Inelasticity of demand represents risk insofar as portfolio participants who do continue to use large volumes of electricity when prices are high (e.g., running air conditioning units during hot summer afternoons) do not carry the full direct cost of their usage.

The above is not well articulated and is erroneous in several respects. Relatively static retail rates (relative to wholesale spot prices, which seem to be what the Draft Plan means by "prices") do not cause demand inelasticity. Rather, they prevent the demand elasticity from manifesting itself over the period where the rates are kept static. The underlying demand may be elastic or inelastic; it matter not if rates do not change. In any event, this is not a source or a cause of “load uncertainty.” Quite the contrary, it provides greater load certainty, albeit at the potential cost of greater economic inefficiency. Furthermore, while the rates of most customers do not vary by hour, customers may select that option. Even if they do not select hourly pricing service, their rates still do change periodically, as the utility’s electricity procurement costs change (most prominently every June and October).

Fifth, in its discussion of “Time Frames for securing products and services,” the Draft Plan states

> Time frames for securing products and services present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time.

(Draft Plan, Subsection 2.3.1.4, p. 9) However, the Draft Plan does not explain what is meant by the statement that “the underlying volatility in electricity markets places a premium on time.” First, while the interaction between market participants may lead traded forward prices to exhibit premiums, and while the level of such premiums may certainly be related to volatility in the underlying commodity’s prices, the Draft Plan provides no insights into those connections. Indeed, the remainder of the subsection appears to be concerned with two seemingly unrelated things, and both are seemingly unrelated to the concept of “volatility” placing “a premium on time.”

XI. Conclusion

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

Respectfully submitted,

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Appendix A

Average Power Output Expectations Associated with the 20-year Renewable Energy Contracts Resulting from the December 2010 Procurement				
Starting 2012	**ComEd**		**Ameren**	
Mo	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
June	164.0	171.4	77.1	80.7
July	139.8	147.7	68.2	70.9
August	155.8	163.0	75.3	77.9
September	163.7	166.3	75.6	79.1
October	134.4	140.4	64.4	69.4
November	100.5	108.8	46.7	51.4
December	102.5	113.7	47.9	53.0
January	95.9	110.5	45.2	52.7
February	124.3	139.4	60.5	68.5
March	145.1	156.8	68.4	74.1
April	163.6	176.0	78.7	84.2
May	179.1	186.5	83.9	86.6