STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

In the matter of the

Public Notice of Informal Hearing (Request for Comments)

Concerning the 2012 Electric Procurement Events

Which Were Held on Behalf of Commonwealth Edison Company

and Ameren Illinois Company

Pursuant to 220 ILCS 5/16-111.5(o)

INITIAL COMMENTS BY THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

JESSICA L. CARDONI
JOHN C. FEELEY
JOHN L. SAGONE
Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street, Suite C-800
Chicago, IL 60601
Phone: (312) 793-2877
Fax: (312) 793-1556
jcardoni@icc.illinois.gov
jfeeley@icc.illinois.gov
jsagone@icc.illinois.gov

Counsel for the Staff of the Illinois Commerce Commission

June 14, 2012

Contents

I. Introduction

The Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, submits these Initial Comments in the matter of the Commission's Public Notice of Informal Hearing (Request for Comments) Concerning the 2012 Electric Procurement Events Which Were Held on Behalf of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren"). The notice was issued on May 17, 2012, pursuant to 220 ILCS 5/16-111.5(o).

While these comments are submitted to the Illinois Commerce Commission, the intended audience is primarily the Illinois Power Agency ("IPA"), and the intended purpose is to influence decisions by the IPA with respect to the content and implementation of the next procurement plan.

II. Energy Hedging

The most significant component of purchased electricity costs is the energy component. This component is derived from expenditures on (and sales of) various types of "energy" products—some involving physical delivery and some only involving financial settlement. The relevant markets for these products include over-the-counter markets for forward contracts and financial swap contracts and spot markets organized by the RTOs, like PJM and MISO.

ComEd and Ameren could purchase all of the electricity needed to serve eligible retail customers in the day-ahead and real-time spot markets operated by PJM and MISO. However, on the utilities' behalf, the IPA has opted to hedge against unanticipated spot market price movements, by purchasing both forward contracts and financial swap contracts, with delivery (or financial settlement) periods from about 2 to

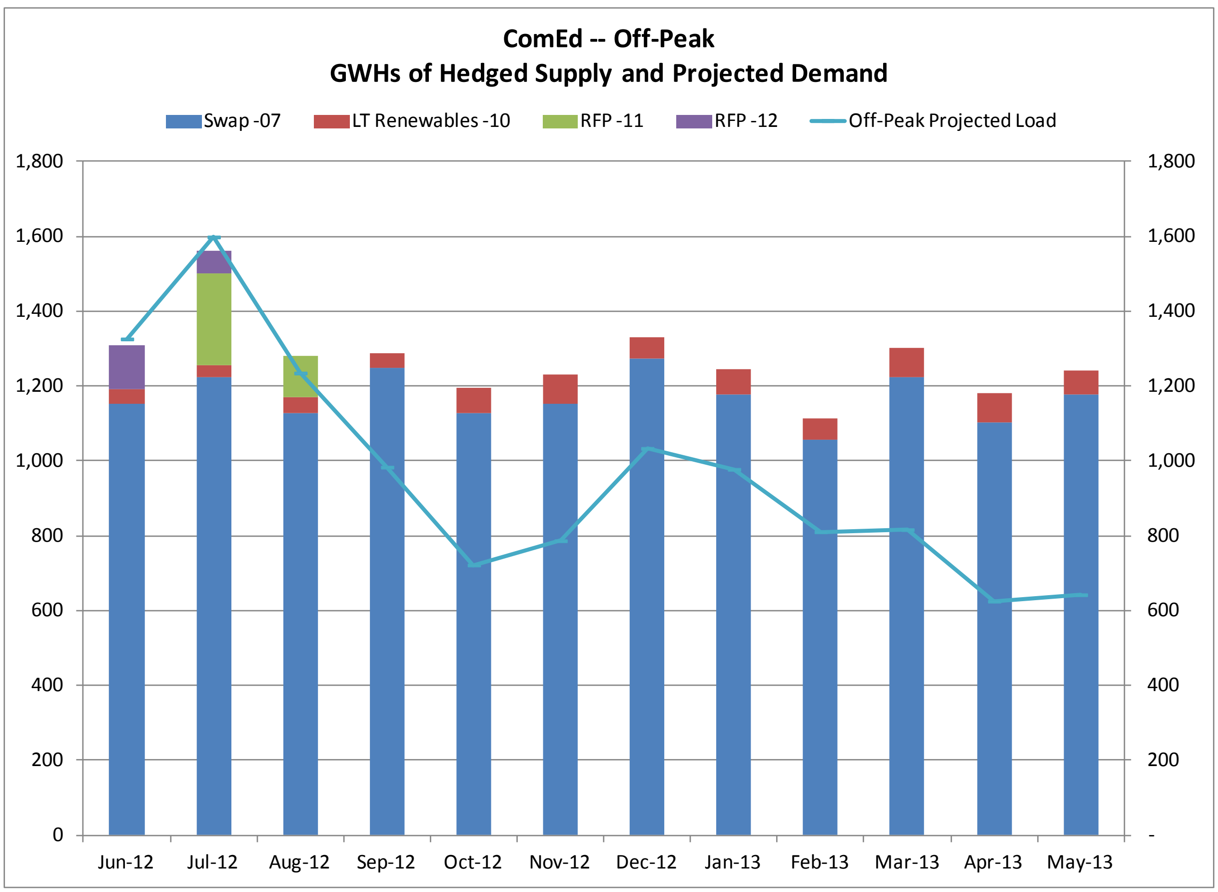
40 months beyond of the transaction date. More specifically, the IPA's hedging strategy has been to accumulate such contracts, through annual procurement events, in quantities equal to specific planned portions of the expected average load for each hour of the next three plan years, in 72 discrete delivery periods (72 = 3 years x 12 months x 2 hour types -- the two hour types being "on-peak" and "off-peak"). At each procurement event, fixed-quantities have been added to the portfolio, as needed to get as close to the following hedge ratios as possible:

Fixed Price Hedge Quantities, as a % of Expected Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	Current PY + 1	Current PY + 2
100%*	70%	35%
* In some plans, the IPA sought to obtain 110% of the expected average hourly load for the July and August on-peak time periods.		

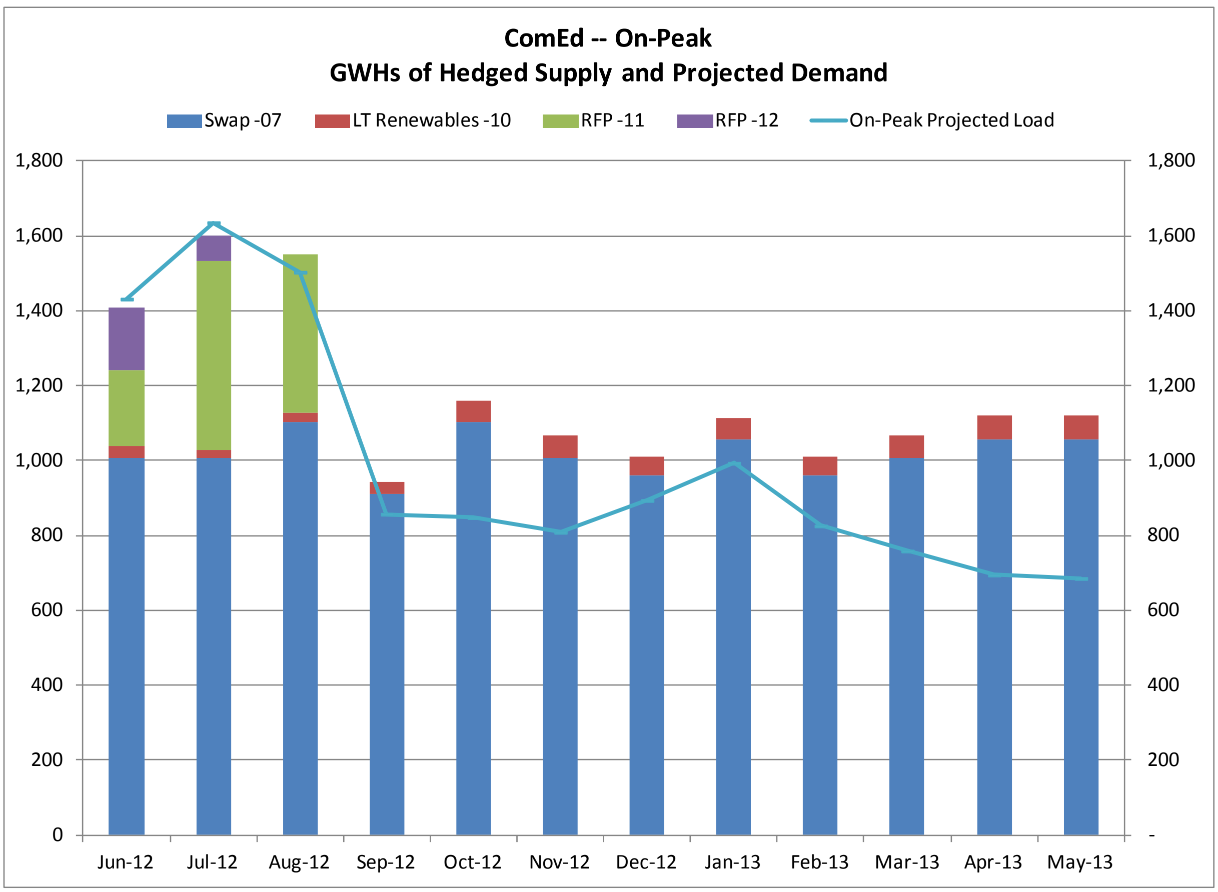
On net, the above hedging strategy has been an expensive one. Between June 2009 and May 2012, due to relatively low spot prices, net losses on the IPA's hedging contracts have been approximately $44 million. However, the quantities hedged through the IPA have been relatively minor compared to the total quantities hedged. If we include the pre-existing 5-year fixed-quantity swap contracts with the utilities' affiliates that were approved by the General Assembly in 2007 and the one-year fixed-quantity contracts that were added in 2008 (both prior to the IPA's tenure), then the net losses on all of these forward fixed-quantity contracts has been approximately $2 billion over four years.

Admittedly, the above assessment is based on hindsight. Furthermore, it is the function of buyers' hedges to result in losses when spot prices fall relative to initial expectations, just as they result in gains when spot prices rise relative to initial expectations. In both cases, however, as long as the quantities hedged are close to actual usage, the effective net prices experienced by the hedger remain close to the level of the original expectations. It just so happened that wholesale market prices have fallen during the period examined above. Therefore, the effective price has remained relatively close to the original hedged prices, except for where the hedged quantities have deviated from the actual levels of demand.

Such quantity deviations have been minor, to date, but for ComEd, hedged quantities are expected to be significantly above actual demand levels during most of the 2012-2013 plan year (see graphs, below), especially in the non-summer months. For example, note that existing supply is almost 200% of projected demand in the May



2013 off-peak period. Furthermore, the vast majority of the hedges in the 2012-2013 ComEd portfolio were established in 2007, at prices that are well-above current wholesale price levels. What, in effect, amounts to excess electricity is expected to be sold back to the market at a loss, raising the company's average energy costs above the prices that were "locked-in" by the hedges. Thankfully, for eligible retail customers, those 2007 contracts will expire at the end of the 2012-2013 plan year. While there is still a risk that there will be too much hedged supply during the 2013-2014 plan year, due to the hedges established during the February 2012 "rate stability" procurement, the prices of those contracts are significantly lower than the prices of the 2007 contracts, and probably will be more in line with 2013-2014 spot prices. Hence, they will not have a significant impact on retail prices.



In Staff's view, the main reason why expected demand during the 2012-2013 plan year is significantly below hedged quantities is the inter-related phenomena of customers switching to alternative retail electric suppliers ("ARES") and the high costs of the utilities' portfolios relative to current market prices. Because of the latter phenomenon, and other exogenous factors that have reduced ARES' marketing and bad debt expenses, ARES have been able to offer small retail customers significant dollar savings and still cover their costs.

Nevertheless, the exact opposite may occur in the future. That is, if market prices begin to rise relative to the utilities' portfolio at any given point in time, some customers are likely to discover that they would be able to save money by switching back to utility supply service. However, for any given cost advantage, ARES-to-utility shifts are likely to be less pronounced and to occur less rapidly than utility-to-ARES shifts because: (a) the utilities will not be actively marketing their supply services; (b) the utilities' supply charges and other terms and conditions for providing service are governed in part by tariff rather than entirely by market forces, and are therefore less flexible; (c) the utilities are prohibited against imposing exit or significant entrance fees on small customers, whereas ARES' contracts may include set terms of 12 months or more with penalties for early termination.

In any event, as long as there remain significant differences between the electric utilities and ARES in their energy cost structures and regulatory environments, it is reasonable to expect that significant swings in their market shares will occur. While individual ARES are largely free to implement their own strategies for adapting to those swings, the electric utilities' strategies must be vetted by the IPA and/or the Commission and must be consistent with applicable statutes, administrative rules, and tariffs.

To address the above-described situation, Staff recommends that the IPA modify its planning process as follows. First, to the extent possible, the IPA should incorporate into its risk modeling differences between the utility's purchased electricity charges and current market prices, and the impact of such differences on eligible retail customer load. Second, the IPA should consider reducing the degree to which it relies upon fixed-quantity fixed-price forward contracts for meeting the expected (but unknown) future demands of eligible retail customers, especially for periods beyond the first year included within each plan. For example, Staff offers the following alternative proposals for the IPA to analyze:

Energy Hedging Plan: Staff Proposal 1

Fixed Price Hedge Quantities, as a % of ***Expected*** Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	Current PY + 1	Current PY + 2
75%	50%	25%

Energy Hedging Plan: Staff Proposal 2

Fixed Price Hedge Quantities, as a % of ***Low Load Forecast*** Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	Current PY + 1	Current PY + 2
90% to 100%	60% to 70%	30% to 40%

Either of the above two hedging proposals would or could have the following benefits:

1. The utility's remaining eligible retail customers would suffer lower financial losses from the utility holding "out-of-the-money" forward contracts.
2. Customers would oscillate less between utility supply and ARES supply, due to transitory differences in cost structures.

3. Retail rates may better reflect the marginal cost of supply, which may lead to more economically efficient levels of consumption.[1]

III. Improving Procedures for Approving "Other Alternative Sources of Environmentally Preferable Energy"

Section 1-10 of the IPA Act includes a definition of renewable energy resources, which limits the resources that the IPA can utilize to satisfy the renewable energy portfolio standard imposed by Section 1-75(c) of the IPA Act. The definition explicitly lists several specific resource types, but the definition also includes the open-ended type, "Other Alternative Sources of Environmentally Preferable Energy." Thus, there must be a mechanism for determining which resources fit this open-ended category and for relaying those determinations to the procurement administrator, the procurement monitor, potential bidders in the IPA's RFPs, and eventually the utilities who contract with the winning bidders and take delivery of the RECs tied to these Other Alternative Sources of Environmentally Preferable Energy. While the IPA Act does not clearly identify who must make these determinations, the IPA has asserted jurisdiction in this regard. Nevertheless, Staff recommends that the IPA refine its mechanism for determining which resources fit the open-ended category and for effectively disseminating that information to the necessary parties.

First, Staff notes that the IPA's web site already includes a page devoted to renewable resources, including a *.pdf file concerning eligible generators. This file

[1] That is, if the retail rate includes a larger share of more contemporary market prices, they will increase more during temporary periods of enhanced scarcity and decrease more during periods of relative abundance. Thus, consumption of electricity will stop closer to the point at which the incremental value of that consumption to the consumer equals the incremental cost of generating and delivering that electricity. Staff does not wish to exaggerate the potential for enhancing economic efficiency in this manner, though. First, the changes in the hedging strategy are not that dramatic. Second, improving economic efficiency would also require significant changes to rate design.

includes instructions for contacting the IPA if a resource owner wants its facility to be included in the list of eligible facilities maintained by PJM-EIA or M-RETS. If it has not already done so, the IPA should take steps to minimize the amount of time that such requests are processed.

Second, since PJM-EIA and M-RETS only list actual facilities, and since there are potential suppliers whose facilities are still in the planning stage but would only be eligible if they ultimately fit into the IPA's view of "Other Alternative Sources of Environmentally Preferable Energy," the IPA should publish rules governing how it makes such determinations. Better still, the IPA should publish rules that include procedures for obtaining provisional approval of facilities that are still in the planning stage. The goal of such rules would be to minimize uncertainty faced by resource developers, who must otherwise invest without any assurances that their resources will be found to meet the requirements of the Illinois renewable portfolio standards. They also protect resource developers and resource owners against potentially arbitrary and capricious decision making by the IPA.

Third, the IPA should ensure that its procurement administrators are aware of the IPA's processes and timetables for adding resources to the lists of eligible facilities maintained by PJM-EIA and M-RETS. The IPA's procurement administrators should also endeavor to disseminate this information to potential bidders and should ensure that the information is given to all bidder/applicants in the IPA's renewable energy procurements.

IV. Issues Arising from Section 1-75(c)(5) of the IPA Act

A. Introduction

Section 1-75(c)(5) of the IPA Act states:

> (5) Beginning with the year commencing June 1, 2010, an electric utility subject to this subsection (c) shall apply the lesser of the maximum alternative compliance payment rate or the most recent estimated alternative compliance payment rate for its service territory for the corresponding compliance period, established pursuant to subsection (d) of Section 16-115D of the Public Utilities Act to its retail customers that take service pursuant to the electric utility's hourly pricing tariff or tariffs. The electric utility shall retain all amounts collected as a result of the application of the alternative compliance payment rate or rates to such customers, and, beginning in 2011, the utility shall include in the information provided under item (1) of subsection (d) of Section 16-111.5 of the Public Utilities Act the amounts collected under the alternative compliance payment rate or rates for the prior year ending May 31. ***Notwithstanding any limitation on the procurement of renewable energy resources imposed by item (2) of this subsection (c), the Agency shall increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31.***
>
> (20 ILCS 3855/1-75(c)(5), emphasis added)

Generally, there are two reasonable ways to interpret the emphasized portion of the above excerpt concerning the disposition of alternative compliance payment (“ACP”) revenues collected from the utilities’ customers on hourly pricing tariffs:

A. If the “item (2)” spending limit prevents the IPA from either meeting any of the utility’s renewable energy percentage requirements or fully satisfying any of the statutory preferences concerning the type or location of renewable resources acquired, then the IPA must tap into the ACP revenues previously collected from hourly customers to supplement the renewable energy budget for that “next plan year”; or

B. Whether or not the spending limit prevents the IPA from meeting any of the utility’s percentage requirements or fully satisfying any of the preferences, the IPA is required to spend, in that “next plan year,” the ACP revenues collected from hourly customers, and to spend those ACP revenues on renewable energy resources.

While the last procurement plan did not explicitly assert either of the above interpretations, it implicitly adopted interpretation A. It did this by including the hourly customer ACP revenues in the renewable energy resource spending budgets for eligible retail customers, without specifying any contingency plan if some or all of those funds proved unnecessary to meet the renewable energy percentage requirements or to satisfy the statutory preferences over resource type and location. Furthermore, it is apparent that, during implementation of the plan, the IPA's procurement administrators were given no instructions to purchase additional renewable energy resources with the available ACP funds. This is apparent because all the renewable energy requirements and preferences tied to eligible retail customers' loads were met without exceeding the statutory spending limits, and yet no additional renewable energy resources were acquired with the supplemental ACP revenues that were available.

The circumstances and events described above lead Staff to raise the following questions at this time:

- Are interpretations A and B equally reasonable, or is one interpretation more defendable than the other?
- How should the next plan and its implementation be modified with regard to ACP revenues collected from hourly customers?
- How, if at all, and to which customers, if any, should previously-collected but unspent ACP revenues be credited; or should those funds be carried forward and spent during implementation of the next plan?

Ultimately, the Commission should answer these questions. However, Staff raises them here so that they may be discussed by interested parties and considered by the IPA prior to its next plan filing.

For its own part, Staff opines that Interpretation B is somewhat more defensible than Interpretation A and that the next plan should reflect Interpretation B. Furthermore, previously-collected but unspent ACP revenues (as Staff will identify more explicitly below), should be credited to eligible retail customers through existing purchased electricity cost-recovery riders, rather than carried forward and spent during implementation of the next plan. In support of these positions, Staff argues as follows:

B. Interpreting Section 1-75(c)(5) of the IPA Act

In defense of interpretation (A), Section 1-75(c)(5) does not explicitly establish supplemental REC targets. It does not state that the quantities of RECs must increase in order to meet the renewable portfolio standard. Instead, it states that the **"*spending*" … "*shall increase*" … "*notwithstanding*"** the spending limits otherwise established in 1-75(c)(2). Thus, it is reasonable to conjecture that this provision authorizes additional spending to the extent that the spending limits established in Section 1-75(c)(2) otherwise prevent the attainment of the REC quantity requirements explicitly included in Section 1-75(c)(1).

On the other hand, Section 1-75(c)(5) does not say that the additional spending is contingent upon the inability to meet the requirements of 1-75(c)(1) within the 1-75(c)(2) spending limits. Therefore, Staff concludes that, each plan year, the IPA should spend the ACP revenues that were collected by the utilities from hourly customers during the "prior year ending May 31," and to spend those ACP revenues on renewable energy resources: (i) to help fulfill the requirements of paragraphs (1) through (4) of Section 1-75(c), and, to the extent to which there are still funds remaining,

(ii) to purchase additional renewable energy resources above and beyond the requirements of paragraphs (1) through (4) of Section 1-75(c).

C. How the next procurement plan should be modified

Staff recommends that the next plan include the following details for implementing Section 1-75(c)(5). In particular, the plan should not only quantify the ACP revenues available for spending on renewable energy for the upcoming plan year, the plan should also explain that the funds will be used: (i) to supplement the traditional renewable budget to help fulfill the requirements of paragraphs (1) through (4) of Section 1-75(c), and, to the extent to which there are still funds remaining, (ii) to purchase additional renewable energy resources above and beyond the requirements of paragraphs (1) through (4) of Section 1-75(c). With respect to (ii) purchasing additional renewable energy resources above and beyond the requirements of paragraphs (1) through (4) of Section 1-75(c), the IPA should specify a goal. Staff believes the IPA has significant leeway in this regard, since the IPA Act provides no direct guidance for purchasing additional renewable energy resources above and beyond the requirements of paragraphs (1) through (4) of Section 1-75(c). For instance, the goal could simply be to acquire one year contracts for as many Illinois/adjoining state unbundled RECs as possible, or to do so while maintaining a ratio of wind RECs to total RECs of at least 75%, a ratio of solar PV to total RECs of at least 1.5%, and a ratio of distributed generation RECs to total RECs of at least 0.5%. However, other equally defensible ways of structuring the purchase of additional renewable energy resources (above and beyond the requirements of paragraphs (1) through (4) of Section 1-75(c)) could be devised.

D. Disposition of previously-collected but unspent ACP revenues

While the above proposals for formulating and implementing future procurement plans would dispose of ACP revenues from hourly-customers collected during the June 2011-May 2012 plan year and beyond, they do not deal with the revenues that were collected during the June 2010-May 2011 plan year, which will remain unspent. In Staff's view, it is too late to use the June 2010-May 2011 funds for purchasing renewable energy resources, since the Act clearly limits the use of ACP revenues from hourly-customers to "***the next plan year***." This cycle of ACP collection and spending is illustrated by the following timeline diagram:

Timeline for Collecting ACPs from Hourly Supply Customers and Subsequently Spending those Funds on Renewable Energy Resources					
	June - May Period:				
	2010	**2011**	**2012**	**2013**	**2014**
	to	**to**	**to**	**to**	**to**
	2011	**2012**	**2013**	**2014**	**2015**
Cycle					
1	collect	plan	spend		
2		collect	plan	spend	
3			collect	plan	spend

Instead, in Staff's view, the funds collected during the 2010-2011 period should be credited to the electric supply cost-recovery riders applicable to eligible retail customers. Staff's recommendation is based on the following considerations:

First, the Commission has already approved an ACP rate calculation methodology that is adjusted downward by the ratio of the ACP revenues from hourly customers divided by the total REC spending budget. Thus, ARES and real-time customers will be enjoying lower ACP rates during the current 2012-2013 year, as a result of implicitly treating the 2010-2011 ACP revenues as if they would be used solely to reduce the rate impact of renewable energy expenditures made by the utilities on behalf of their eligible retail customers. These lower ACP rates would approximate the increase in rates paid by eligible retail customers for renewable energy resources, if the 2010-2011 ACP funds are in fact credited to such customers.[2]

Second, if the 2010-2011 ACP revenues are not credited to eligible retail customers, that leaves three alternatives, none of which is satisfactory:

(i) The utility could return the funds to the hourly customers. However, this would mean that, on net, hourly customers would end up paying nothing toward the State's renewable portfolio standard in 2010-2011. Surely, this was not the intent of the legislature, when it enacted Section 1-75(c)(5) of the IPA Act.

(ii) The utility could simply retain the funds for its shareholders. However, it hardly seems fair for the State to impose what essentially amounts to a renewable energy tax on retail customers, and then allow its tax collector (the utility) to retain the revenues, rather then use them for the State's intended purpose.

(iii) The utility could retain the funds for a future REC RFP. However, as explained above, Staff believes that possibility is barred by the IPA Act.

This leaves only one option that makes sense. The ACP funds collected from hourly customers during the 2010-2011 period should be credited to the electric supply cost-recovery riders applicable to eligible retail customers.

[2] That is, the two rates would be nearly the same if there was not also a requirement for the ACP rate, for the next two plan years, to exclude the impact of solar PV REC purchases. In addition, if all of the 2010-2011 ACP revenues had been needed and were being used to purchase RECs for eligible retail customers, the same ACP rate methodology would have resulted in the 2012-2013 ACP rates equaling the maximum ACP rate that was specified in the last procurement plan.

V. CONCLUSION

Staff respectfully requests that the Illinois Commerce Commission, the Illinois Power Agency, and all other interested parties make note of Staff's initial comments in this informal hearing.

Respectfully submitted,

/s/ ____________________________

JESSICA L. CARDONI
JOHN C. FEELEY
JOHN L. SAGONE

Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street, Suite C-800
Chicago, IL 60601
Phone: (312) 793-2877
Fax: (312) 793-1556
jcardoni@icc.illinois.gov
jfeeley@icc.illinois.gov
jsagone@icc.illinois.gov

Counsel for the Staff of the Illinois Commerce Commission

June 14, 2012