# Comments Pursuant to Section 16-111.5(d)(2) of the Public Utilities Act

Illinois Competitive Energy Association

September 15, 2014

Pursuant to Section 16-111.5(d)(2) of the Public Utilities Act,[1] ICEA is pleased to present its comments on the Illinois Power Agency's ("IPA") 2015 Draft Plan for public comment, issued on August 15, 2014.

## I. Introduction

The Illinois Competitive Energy Association ("ICEA") is a nine-member, Illinois-based trade association of many of the largest and most active retail electric suppliers ("RES") seeking to preserve and enhance opportunities for customer choice and competition in the Illinois retail electric market.[2] ICEA's members serve residential, commercial, industrial and public sector customers, ranging from Main Street to the Fortune 500, including the manufacturing industry; retail businesses; the State of Illinois and local units of governments; cultural, sporting and educational institutions; as well as hospitals, hotels and restaurants. ICEA members also provide service to virtually all of the municipalities that have enacted Governmental Aggregation Programs in the Ameren Illinois Company ("Ameren") and Commonwealth Edison Company ("ComEd") utility service territories. As noted by the Office of Retail Market Development at the Illinois Commerce Commission ( "Commission") in its 2014 Retail Electric Competition Report, RES provide between 73% and 81% of the electricity consumed in each of Ameren's three rate zones over 81% of the electricity consumed in the ComEd service territory.[3] The same report noted that RES serve 63% of small customers (0-100kW) in ComEd, and between 65%

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[1] *See* 220 ILCS 5/16-111.5(d)(2).

[2] ICEA members include Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Integrys Energy Services, LLC; MC Squared Energy Services, LLC; FirstEnergy Solutions Corp.; Nordic Energy Services, LLC; NextEra; and Verde Energy USA-Illinois.

[3] Office of Retail Market Development, 2014 Annual Report at 7-10.

and 67% of the same sized customers across each Ameren rate zone.[4] These small customers are a significant portion of customers that may be "eligible retail customers," the customers that take bundled supply from utilities secured by the IPA through its procurement process.[5]

ICEA has a direct interest in the IPA 2015 Draft Power Procurement Plan,[6] because the IPA's structure for procuring electricity for eligible customers impacts those customers in two ways. First, the transparency and predictability of price risk impacts customers' ability to benefit from retail competition and their choices of electric supplier. Second, unless and until the 2015 Draft Plan fully evaluates the fixed price full requirements ("FPFR") approach, the Commission will be unable to definitively conclude which procurement approach is more beneficial for any customer (whether on the bundled product or with RES service). Therefore, ICEA appreciates the opportunity to provide comments for the IPA's consideration regarding the 2015 Draft Plan in advance of the IPA filing with the Commission.

As will be discussed in detail below, ICEA recommends adding a four-year pilot program to evaluate a fixed price full requirements product against the performance of the IPA's current approach.

## II. ICEA Recommends That The IPA Adopt a FPFR Pilot Program And Remove The Discussion of Obstacles To FPFR

In the version of this 2015 Procurement Plan to be filed with the Commission, ICEA respectfully requests that the IPA adopt a four-year limited pilot FPFR program within the ComEd service territory.[7] The purpose of this pilot will be to compare the performance of the

[4] *Id.*
[5] *See* 220 ICSS 5/16-111.5
[6] 2015Illinois Power Agency Electricity Procurement Plan – Draft Plan for Public Comments, August 15, 2014. ("2015 Draft Plan"). All references to the 2015 Draft Plan, unless otherwise specifically noted, refer to this document, as opposed to the Draft Procurement Plan to be filed with the Illinois Commerce Commission for approval pursuant to 220 ILCS 5/16-111.5(d)(2).
[7] ICEA is not recommending FPFR for Ameren at this time.

IPA's existing (and ongoing) block and spot procurements against actual IPA-run FPFR procurements. Four years of data will allow the Commission to make a fact-based determination using actual market data as to whether FPFR best meets the requirement of Section 16-111.5(d)(4) of the Public Utilities Act, the standard for the Commission approving the procurement plan.[8]

The specific product that ICEA recommends that the IPA procure is based on the presentation delivered to the June 5, 2014 IPA Workshop on FPFR products ("ICEA Presentation"),[9] as clarified in the IPA's comments to the IPA's subsequent Request for Comments ("ICEA FPFR Comments.")[10] To summarize, the general concept is that market-based charges, such as energy and ancillaries,[11] are included in the product, while non-market based charges are not.[12] Although capacity (peak load contribution, or PLC) and network services transmission (network services peak load, or NSPL) are market-based, ICEA recommends that these PJM allocated peak load related costs be excluded because ComEd has already committed to unbundling at the wholesale level and may end up unbundling retail rates in the future.[13]

Recognizing that the FPFR purchase is part of a limited pilot during which block and spot purchases will continue, ICEA proposes that the IPA integrate the two by separating out FPFR

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[8] *See* 220 ILCS 5/16-111.5(d)(4).

[9] The slide deck presented by ICEA and NorthBridge is available at: http://www2.illinois.gov/ipa/Documents/ICEA-presentation-on-FR.pdf.

[10] ICEA's comments are available at: http://www2.illinois.gov/ipa/Documents/ICEA-Responses-IPA-FPFR-Questions.pdf.

[11] ICEA anticipates that charges related to compliance with the renewable portfolio standard will also go into bundled supply, but wishes to clarify that ICEA does not recommend at this time altering the IPA's approach to procuring renewable resources with regard to the pilot program.

[12] For a fuller list of proposed included and excluded components, please see ICEA Presentation at 2-3 and ICEA FPFR Comments at 1.

[13] *See, e.g.*, ICEA FPFR Comments at 1.

tranches from the block and spot tranche.[14] In other words, if FPFR is procured for 20% of the portfolio, block and spot (both past and contemporary procurements) would be used to address 80%. Thus, if at a given hour demand by eligible retail customers is 5,000MW, using the same percentages the FPFR suppliers collectively would be responsible for 1,000MW of supply, while the utilities would balance supply under contract with 4,000MW of demand using the spot market. To describe further, if the IPA had procured 3,500MW for that particular time period, the utility would have to balance by buying 500MW; if the IPA had procured 5,500MW, the utility would balance by selling 1,500MW. Even though all eligible retail customers would see one single rate (with a PEA), the Commission, IPA, Staff, and stakeholders will be able to see how the block and spot approach compares with the FPFR approach with a backward-looking analysis of the sum of those transactions over the course of the year.

ICEA recommends that the 2015 Draft Plan sent to the Commission for approval authorize a 25% tranche of the total load to go to FPFR each of the four years, with FPFR procured as a one-year product while the blocks are procured in the same laddered manner. This will allow an apples-to-apples comparison, and should function for the duration of the pilot because the IPA aims to have 50% of supply needs under contract going into the last procurement before the delivery year.[15]

In order to revise the draft plan to accommodate ICEA's recommendation, ICEA understands that several of the arguments against adopting an FPFR approach at this time must be addressed. ICEA recommends modifying the 2015 Draft Plan to delete or further explain those arguments as described in more detail below, for the reasons stated below. Simply stated, ICEA respectfully submits that, as currently written for public comment, the 2015 Draft Plan

[14] *See, generally*, ICEA Presentation at 5;FPFR Comments at 2-3.
[15] *See* 2015 Draft Plan at 48-49.

does not present adequate rationale for not adopting a limited FPFR pilot, as supported by the NorthBridge Report. ICEA also urges changes to the 2015 Draft Plan to better respond to the most recent Commission order regarding the 2014 Procurement Plan. To effectuate these proposed changes, ICEA is including proposed revisions to the 2015 Draft Plan attached as Appendix A.

## III. The Commission's Order And Required Analysis

The Commission addressed FPFR in the IPA's most recent approved procurement plan ("2014 Procurement Plan"), specifically in ICC Docket No. 13-0546. As part of that docket, ICEA presented a thorough report entitled, "*Merits of Incorporating Fixed-Price Full Requirements Products in the Illinois Power Agency Plan,*" prepared by the NorthBridge Group ("NorthBridge Report"). This report is attached to these comments as Appendix B. The NorthBridge Report provided substantial evidence, analysis, and support for using FPFR products to serve eligible retail customers:

- Describing the benefits of using FPFR products to satisfy utility supply service requirements.

- Explaining that the FPFR product approach has become by far the most prevalent and favored form of utility supply procurement for smaller customers in restructured jurisdictions.

- Presenting robust quantitative analysis based on actual market data from a jurisdiction in which the block-and-spot approach (which is the basic approach currently utilized by the IPA) and the FPFR product approach simultaneously had been implemented, which indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is reasonable.[16]

- Providing a straightforward analysis that shows that customers in Illinois have indeed been subject to costs and unnecessary adverse financial risks under the block-and-spot approach, due to the inability of this approach to match the quantities of fixed-

[16] In particular, the Commission identified this analysis as "compelling." (*See* ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 95.) ICEA agrees with the Commission on its probative value; for the reasons described below, ICEA recommends setting up a similar comparison in Illinois with a pilot program.

price supply purchased with the uncertain load requirements. That analysis also identifies the significant monthly variations in the PEA that are necessitated by the supply/load mismatches under the block-and-spot approach have distorted the bundled service rates against which RES compete. The analysis presents ComEd data that indicates that, in a period spanning only three months, the block-and-spot approach caused almost $100 million in additional costs that must be deferred for recovery from customers in future periods.

- Explaining in depth how analysis presented by the IPA in its 2014 Draft Plan contains significant shortcomings that made that analysis unable to provide useful information regarding the relative merits of the FPFR product approach as compared to the block-and-spot approach.

With the NorthBridge Report in evidence, the Commission responded, in part, as follows:

> The Commission appreciates ICEA's efforts in raising this issue and providing the Northbridge Report. ICEA has raised the level of discussion surrounding this particular issue, and the Commission welcomes these efforts. . . .
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> While the Commission appreciates ICEA providing the NorthBridge Report, Staff indicates it has not had adequate time to fully analyze the Report. Similarly, while the Commission itself has reviewed the NorthBridge Report, it is not comfortable with the level of review and feedback other parties provided. Staff, for example, also expressed concerns about the level of review performed by the IPA, the AG, and CUB. . . . The Commission has endeavored to review the record notwithstanding the limited timeframe. **Some of the findings in the report are compelling**, including the 2012 analysis of the PECO Energy Company, **which notably included a simultaneous implementation of the block and spot and fixed price full resource products** as similarly proposed by ICEA in this proceeding. Additionally, the report highlights several drawbacks with the IPA's analysis of the different procurement approaches. **The Commission observes that Staff agrees with several of these critiques**, and the IPA amended its analysis to address these issues. . . .
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> For purposes of next year's plan, **the Commission directs the IPA to include a more thorough and accurate analysis of the impacts of incorporating full requirements products into its procurement strategy, including the balance of benefits-to-premium costs of those products and any significant implementation costs it believes will result from this shift in procurement strategy.** The Commission is hopeful that this directive will allow the parties adequate time to consider this issue in the next proceeding.[17]

[17] ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 94-96 (emphasis added, internal citations omitted).

Although the Commission ultimately did not adopt ICEA's recommendation in the IPA's 2014 Procurement Plan, the Commission did set important groundwork, both holding that FPFR is a "standard product" and directing the IPA and interested parties to respond more fully to the NorthBridge Report.[18]

After the Commission's Final Order, the IPA held a workshop on FPFR products at which the IPA graciously allowed ICEA and NorthBridge to make a live presentation, the ICEA Presentation. In addition, in response to an IPA request for comments, ICEA provided written comments supporting inclusion of a FPFR product in the IPA's 2015 Procurement Plan, the ICEA FPFR Comments. Both the ICEA Presentation and ICEA FPFR Comments provided a working definition of FPFR products that would allow for capacity to either to be part of the product or to be separated from the product should utilities secure approval for capacity unbundling.[19] Also, both made recommendations consistent with the limited FPFR pilot program intended described in detail above, in order to allow the Commission, the IPA, and other stakeholders to make future decisions on FPFR based on Illinois- and IPA-specific experience and data.[20]

ICEA further notes that in response to the IPA's request for comments, Staff provided the following insight:

> For both full-requirements and block-and-spot products, one can attempt to construct bottom-up supplier cost analyses, of the kind attempted by the IPA's

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[18] *Id.*
[19] *See* ICEA Presentation at 2-3; IPA FPFR Comments at 1 ("ICEA's general concept is that market-based products should be part of a fixed price full requirements product, while non-market based products should not. . . . However, with ComEd's move to individual network service peak load (NSPLs) and peak load contributions (PLCs) for residential customers in 2015 and the rollout of smart meters and smart meter benefits in ComEd's territory, ICEA supports including all market based charges except capacity. Given that capacity is a largely a "pass through" demand charge from PJM that is largely known three years in advance and with the importance of providing customers in a smart meter environment with price signals for capacity usage, ICEA supports the continuation of the current policy that capacity is procured from PJM by ComEd for eligible customers.")
[20] ICEA Presentation at 5; ICEA Comments at 2-3

> planning consultant, PA Consulting. Several problems with PA Consulting's analysis were pointed out during the proceeding. Based on those criticisms, refinements are warranted. On the other hand, any attempt to model a typical supplier's costs will fail to take into account differences between suppliers. Ideally, one should be more interested in modeling the "marginal" supplier's costs, since it is that supplier that will set the price in a competitive procurement. Consideration like this render it very difficult to model bidding behavior, so bottom-up supplier cost analyses may not accurately predict the results of either full requirements or block energy RFPs. Direct observation, when and where feasible, may be more useful for measuring the difference between modeled costs and actual bids. Empirically, the difference between modeled costs and actual bids may be strongly correlated with factors such as spot price volatility and, in the case of full-requirements contracts, class load volatility and customer switching volatility.[21]

ICEA agrees with this analysis, in particular that "Direct observation [if] feasible, may be more useful" than a bottom-up model. The limited FPFR pilot program proposed above would be consistent with Staff's stated preferences.

## IV. ICEA Recommends Modification to the Analysis in the 2015 Draft Plan to Respond to the Commission's Directive and Include a Pilot FPFR Program to Compare Approaches

The Commission spoke clearly: parties, and especially the Procurement Plan for Commission approval, were expected to address the NorthBridge analysis. The expected analysis in the Procurement Plan was spelled out in particular detail: "a more thorough and accurate analysis of the impacts of incorporating full requirements products into its procurement strategy, including the balance of benefits-to-premium costs of those products and any significant implementation costs it believes will result from this shift in procurement strategy."[22] ICEA respectfully suggests that the analysis in the 2015 Draft Plan be revised or expanded in order to minimize the risk of not sufficiently addressing the Commission's requests.[23] ICEA

[21] For Staff's Response to the IPA's Request for Comments, please see http://www2.illinois.gov/ipa/Documents/ICC_Staff_Response_to_IPA_Full_Requirements_RFC.PDF.

[22] ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 95.

[23] ICEA assumes and recognizes that the IPA made a good-faith effort at complying with the Commission's Order. Nevertheless, ICEA is concerned that the IPA's analysis does not reach the high bar established by the Commission.

bases this suggestion on three factors: First, the analysis in the 2015 Draft Plan as currently written relies on the same analysis that the IPA provided in its 2014 Procurement Plan, which the Commission acknowledged in its Final Order but found to be an insufficiently "thorough" or "accurate" response to the NorthBridge Report.[24] Second, the 2015 Draft Plan reaches an incorrect conclusion based on its analysis of premiums. Finally, the 2015 Draft Plan as currently written does not adequately support some of its policy characterizations that it uses to support a block and spot approach.

### A. The 2015 Draft Plan Relies on Analysis That The Commission Has Already Identified as Not Adequately Responsive

Although the Commission requested additional analysis directly responsive to the NorthBridge Report, the 2015 Draft Plan continues to rely on the results from the analysis presented in its 2014 Plan.[25] The NorthBridge Report and briefing by ICEA in the previous docket raised several concerns that ICEA believes the 2015 Draft Plan has not sufficiently engaged.[26] ICEA was not alone in this belief: Staff repeatedly indicated that it had similar concerns about analysis from the 2014 Procurement Plan that appears to have made its way into the 2015 Draft Plan.[27] ICEA recognizes that although the IPA stated in the last docket that it "updated its discussion of Full Requirements . . . to respond to some of the criticisms from the

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[24] *Compare* ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 95 ("The question before the Commission now is whether those premiums are outweighed by the 'embedded' premiums included in the block and spot approach. The IPA and ICEA provide competing analyses on this question.") *with id.* at 95-96 ("For purposes of next year's plan, the Commission directs the IPA to include a more thorough and accurate analysis of the impacts of incorporating full requirements products into its procurement strategy, including the balance of benefits-to-premium costs of those products and any significant implementation costs it believes will result from this shift in procurement strategy. The Commission is hopeful that this directive will allow the parties adequate time to consider this issue in the next proceeding.")

[25] 2015 Draft Plan, at 51, 56.

[26] NorthBridge Report, at 22-29.

[27] Comments by the Staff of the Illinois Commerce Commission on the Illinois Power Agency's Draft Power Procurement Plan for Delivery Periods Beginning June 2014 (ICC Docket No. 13-0546), September 16, 2013, at 22-23; Staff of the Illinois Commerce Commission Response to Objections to Procurement Plan (ICC Docket No. 13-0546), October 21, 2013, at 4-8; Staff of the Illinois Commerce Commission Reply to Responses to Objections to Procurement Plan (ICC Docket No. 13-0546), October 31, 2013, at 4-11.

NorthBridge Report,"[28] the Commission nevertheless ordered additional analysis in the Final Order beyond what the IPA had entered into the record. ICEA's recent retroactive inspection of the updated discussion in the 2014 Procurement Plan approval docket is consistent with the Commission's findings, because it appears to ICEA that:

- The IPA in the 2014 did not fully address the flaws in the IPA's analysis that the NorthBridge Report identified, especially those pertaining to the risks to customers associated with the block-spot-approach which the FPFR approach mitigates for customers;[29] and

- The IPA's updated discussion clarifies that estimates in its analyses are "only illustrative,"[30] and thus not fully responsive to NorthBridge's review and synthesis of actual market data.

In contrast to the illustrative analysis presented in the 2015 Draft Plan, the NorthBridge Report relies on actual market data from a region in which the block-and-spot approach and the FPFR product approach simultaneously had been implemented, stands as a valid and robust assessment of the use of FPFR products. This analysis indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is reasonable. The Commission found the discussion of the side-by-side comparison of the two procurement approaches in the PECO service territory "compelling."[31]

The 2015 Draft Plan also states that, under the block-and-spot approach modeled in the NorthBridge Report which involves a 106% hedge target (the IPA's recommended strategy), the top decile of the metric known as "supply cost surprise" is close to the $5/MWH cap on the PEA in Illinois.[32] The 2015 Draft Plan implies that FPFR products should not be included in the

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[28] Verified Reply Brief on Exceptions on Behalf of the Illinois Power Agency (ICC Docket No. 13-0546), December 2, 2013, at 2-3.
[29] See especially the flaws identified on pages 23-29 of the NorthBridge Report.
[30] 2014 Illinois Power Agency Electricity Procurement Plan – Filed for ICC Approval, September 30, 2013 (Redlined Version), at 71.
[31] ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 95.
[32] 2015 Draft Plan, at 57

procurement plan because unexpected supply cost amounts already are smaller than the magnitude of the PEA cap.[33] ICEA disagrees for several reasons. First, the analysis shows that the top decile value for the supply cost surprise under this block-and-spot approach is notably higher than $5/MWH, at $7.40/MWH.[34] Furthermore, as explained in the NorthBridge Report, actual supply cost surprise outcomes could exceed top decile values.[35] This effect is compounded by the fact that there are additional costs and risks that are experienced under a block-and-spot approach that are not captured by the NorthBridge Report's analysis (i.e. the NorthBridge Report underestimates the harmful effects on consumers).[36] Second, "supply cost surprise" is not an absolute measurement of rate volatility, or of the degree to which deferred cost recoveries are required under the block-and-spot approach due to supply costs that are in excess of PEA caps. In fact, in Illinois, the relatively large potential swings in customer switching and other factors have resulted in very large unexpected deviations in supply costs from expected values under the block-and-spot approach advocated in the 2015 Draft Plan—in fact, deviations equal to multiple times the PEA cap, as evidenced by other analysis presented in the NorthBridge Report.[37] Consequently, the analysis indicates that ComEd's deferred cost recovery balance recently increased by almost $100 million in only three months, to be recovered from future bundled service customers.[38] A more thorough look at the results uncovers the fact that the $7.40/MWH supply cost surprise under the block-and-spot approach (with a 106% hedge target) is 169%, or $4.65/MWH, higher than the $2.75/MWH supply cost

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34 NorthBridge Report, at 37.
35 NorthBridge Report, at 37.
36 NorthBridge Report, at 37-38.
37 NorthBridge Report, at 16.
38 NorthBridge Report, at 15-16.

surprise under the FPFR product approach, yet the expected supply rate under the FPFR approach is only 0.2%, or $0.13/MWH, higher than that under the block-and-spot approach.[39]

Because the 2015 Draft Plan does not have updated analysis and appears to have sidestepped some of NorthBridge's substantive criticisms, ICEA believes that the 2015 Draft Plan as currently written may not have yet achieved full responsiveness to the Commission's directive to respond with "more thorough and accurate analysis." ICEA recommends that the 2015 Draft Plan be modified to either acknowledge the accuracy of the NorthBridge critiques, or provide sufficient detail as to why the critiques are not correct. ICEA has proposed revisions in Appendix A that acknowledge the NorthBridge critiques.

### B. The 2015 Draft Plan's Quantification of FPFR Product "Premia" Does Not Support the Rejection of FPFR Products

In its arguments to support not including FPFR products, the Draft 2015 Draft Plan focuses heavily on the "premium" associated with FPFR products. The term, "premium," is used loosely in the electricity industry and can have several different meanings, so it is important to be clear as to what one means when one uses this term so that proper conclusions can be drawn from any quantified "premia." When defining its use of the term, "premium," in the context of FPFR products, the 2015 Draft Plan explains that FPFR products are a form of price insurance and, as such, "A premium for an insurance product is necessary for the supplier to be able to offer the product. From the recipient point of view, insurance is **an added cost when the insurance is not used, but is likely to be a savings in total cost when the insurance is used** (e.g., compare an annual auto insurance premium to the cost of replacing a totaled car)."[40] In other words, the 2015 Draft Plan recognizes that its definition of "premium" entails costs that are

[39] NorthBridge Report, at 37.
[40] 2015 Draft Plan, at 55 n.91 (emphasis added).

incurred with certainty in order to avoid even greater costs that otherwise might occur. Because the relevant uncertainties from which customers are protected through the use of FPFR products are asymmetric,[41] any such FPFR product "premium" does not represent an estimate of the expected additional cost of the FPFR product approach versus the 2015 Draft Plan's proposed approach. Instead, the FPFR product "premium" simply reflects an added cost paid for protection against even greater added costs that otherwise might be incurred by customers under the block and spot approach. To analogize, when someone purchases life, health, auto, homeowners, or fire insurance to avoid catastrophic loss, that person benefits because the insurance allows her or him to avoid even greater costs that may be incurred by the possible loss.[42]

With that definition of "premium" established in the 2015 Draft Plan, it presents a quantification of the "premia" for various actual FPFR product solicitations. First, the 2015 Draft Plan presents its own analysis of the prices obtained for FPFR products for two of the four New Jersey utilities for which such products were obtained, which were used to provide electricity supply for the respective utility's residential and smaller commercial and industrial

[41] For example, FPFR products protect against the generally positive correlation between uncertain changes in usage levels and corresponding market prices. Also, FPFR product suppliers assume asymmetric customer switching risk to the benefit of customers. Specifically, under the FPFR product approach, subject to applicable customer switching rules, bundled service customers can achieve cost savings when market prices drop by switching to ARES service, without increasing the proportion of above-market supply that the remaining bundled service customers must bear, and thereby without adversely affecting the all-in price per megawatt-hour of the supply, unlike would be the case with the block-and-spot approach. Similarly, if market prices rise, then customers can migrate back to bundled service without driving up bundled service rates by requiring the utility to purchase more energy in the now higher-priced market as it would need to do under the block-and-spot approach. Effectively, the FPFR product price acts as a cap on rates, because FPFR products provide guarantees to customers that they will pay no more than the agreed-upon price for the bundled service supply, while still allowing customers to switch to ARES and pay lower prices if they can find a lower price.

[42] Information portrayed on pages 55-56 of the 2015 Draft Plan also indicates that the IPA's FPFR product "premia" should not be interpreted as additional expected costs of the FPFR product approach versus the block-and-spot approach. Specifically, text on page 55 indicates that the FPFR product "premium" is the difference between the expected cost of the "100% Full Requirements" approach and the (lower) expected cost of the "100% Spot Purchase" approach in Figure 6-5, and Figure 6-5 also indicates that the expected cost of the "Hedged Strategy" approach (which text on page 56 indicates is equivalent to the IPA's "usual procurement strategies," in other words, the block-and-spot approach) is also higher than the expected cost of the "100% Spot Purchase" approach.

customers.[43] New Jersey has held auctions for these products every year since 2002, and the 2015 Draft Plan chooses to analyze the prices obtained in the 2009, 2010, and 2011 auctions. The average "premium" calculated for these FPFR products obtained in these auctions is about \$3/MWH, or about 3% of the overall FPFR product price.[44] This result lends no support to the 2015 Draft Plan's conclusion that FPFR products should be excluded from the procurement plan. In fact, the analysis shows the "residual compensation" values calculated by for PECO Energy's residential FPFR product solicitations average \$4/MWH, slightly higher than the somewhat analogous average "premium" calculated for the New Jersey auction.[45]

During the IPA's FPFR workshop, ICEA and NorthBridge explained that residual compensation values do not refer to the difference in expected cost between a block-and-spot approach and a FPFR product approach in the abstract; instead, they simply refer to the winning bid price net of a subset of the expected costs associated with supplying the load which a FPFR product supplier must bear to the benefit of customers, leaving other costs and risks to be covered by the supplier through the residual compensation.[46] The residual compensation values calculated in a separate testimony by Scott Fisher of NorthBridge cited in the 2015 Draft Plan are based on the same underlying data and are consistent with the calculations and results of the robust analysis found in the NorthBridge Report, which indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is

[43] ICEA has not thoroughly reviewed the calculations underlying the IPA's analysis of the New Jersey auctions, so it neither affirms nor denies the validity of the 2015 Draft Plan's calculations.

[44] After filing its 2015 Draft Plan, the IPA informed ICEA that its original analysis of the New Jersey auction results is erroneous, and it provided corrected analysis. The corrected analysis included ratios of the "premium" to FPFR price (both expressed in terms of dollars per megawatt-hour) as follows: -1.84/103.72=-1.8% for 2009 PSE&G, 4.11/95.77=4.3% for 2010 PSE&G, 2.27/94.30=2.4% for 2011 PSE&G, 0.29/103.51=0.3% for 2009 JCP&L, 7.15/95.17=7.5% for 2010 JCP&L, and 6.67/92.56=7.2% for 2011 JCP&L. This corresponds to an average "premium" of \$3.11/MWH, and an average ratio of 3.3%.

[45] 2015 Draft Plan, at 58-60.

[46] This fact also is confirmed by the quote by Mr. Fisher that the IPA included on page 58 of its 2015 Draft Plan: "Residual compensation is defined as what is 'required by suppliers to cover the other costs and risks that I did not individually quantify.'"

reasonable.[47] For instance, in the robust analysis found in the NorthBridge Report, the expected default service supply rate levels under the block-and-spot approaches are only 0.2%-2.7%, less than under the FPFR product approach.[48] Meanwhile, top decile rate shocks are between 62% and 123% greater under the block-and-spot approaches than they are under the FPFR product approach, the top decile values for supply cost surprise are between 169% and 268% higher, and the block-and-spot approaches involve the potential for significant deferred cost recovery balances.[49] Finally, it is important to note that while the 2015 Draft Plan suggests that procuring block products twice per year will be satisfactory to mitigate risks instead of using FPFR products to do so,[50] the NorthBridge Report's analysis actually already considers block-and-spot approaches that involve supply solicitations that occur twice per year, and its results still support the use of FPFR products.

### C. Several of the Policy Arguments in the 2015 Draft Plan Are Inadequately Supported

The 2015 Draft Plan makes several policy arguments that ICEA believes are not sufficiently supported for the Commission to rely on at this time. Those policy arguments

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[47] The 2015 Draft Plan also contains some residual compensation values pertaining to PECO FPFR product solicitations that occurred since the NorthBridge Report was issued. Page 59 of the 2015 Draft Plan suggests that a higher residual compensation value for one of these solicitations, held in January 2014, indicates that events around that time "indicated to suppliers that they had been underestimating, and hence underpricing, the commitments they were taking on." In the northeastern United States at the time of this solicitation, conventional forms of generation were challenged, market prices were especially volatile, average hourly energy price levels were record-breaking, and as a result PJM and the neighboring NYISO filed and requested expedited approvals of changes in their wholesale energy market bidding requirements and in their energy charges. Furthermore, bids were due in multiple other default service supply solicitations on the same day or within one day of PECO Energy's January 2014 solicitation. Consequently, it is quite understandable that potential default service bidders may have needed to divert resources to urgent portfolio management and regulatory issues. In any case, even if FPFR product suppliers are reassessing their market risks since the market volatility of January 2014, this is no reason to reject the inclusion of FPFR products in a procurement plan. If market uncertainty is understood to be higher than it previously was, then the compensation required by FPFR product suppliers to bear the resultant higher costs and risks to the benefit of customers will be higher all else equal, but the assessment of the costs and risks that would be borne by customers under the block-and-spot approach also will be higher. There is no reason why the general tradeoff that has been shown would no longer exist.

[48] NorthBridge Report, at 37.

[49] NorthBridge Report, at 37.

[50] 2015 Draft Plan, at 59, 61.

include arguments about what eligible retail customers desire based on survey results or popular opinion, whether the IPA's unique role counsels for a block and spot approach (or against FPFR), and that all other states that use FPFR have a provider of last resort ("POLR") utility supply product rather than a default service product. ICEA recommends that the 2015 Draft Plan be amended to reconsider these arguments, or provide additional factual documentation.

1. ICEA urges the IPA to not rely on the surveys presented, or alternatively acknowledge that the surveys do not recommend against FPFR

First, the 2015 Draft Plan presents the results of two surveys in order to support the exclusion of FPFR products from the procurement plan. The 2015 Draft Plan's apparent conclusion is that both surveys indicate that customers generally are not willing to pay the additional expected cost of FPFR products, in spite of the benefits that these products offer. Notwithstanding the 2015 Draft Plan's apparent interpretation, the survey results actually appear to indicate that many customers may indeed prefer the use of FPFR products.

The first survey is a September 2012 survey of electricity customers in Alberta, Canada.[51] This survey found that:

- 13% of customers were willing to "pay a premium price, knowing that the price will not change for a year or more."
- 36% of customers "want[ed] a reasonable price, knowing that the price is fixed for several months."
- 50% of customers "want[ed] the lowest average price, even if that price changes frequently."
- 2% of customers did not know what they wanted.

While the 2015 Draft Plan is not totally clear as to its interpretation of these survey results, it implies a contention that only 13% of customers (those willing to pay a premium price) would be

[51] 2015 Draft Plan, at 60.

willing to pay for FPFR products, while 36% of customers (those desiring a "reasonable price" that is fixed for several months) would prefer the current block-and-spot approach.[52] ICEA has two issues with this conclusion: first, a fixed price over several months (12, in fact) exactly describes FPFR, especially given NorthBridge's demonstration that the residual compensation is relatively small and likely "reasonable." Second, ICEA wishes to emphasize the caveat that 50% of customers wanted "**the lowest average price**, even if that price changes frequently." As NorthBridge (and the 2015 Draft Plan's analysis) shows, there is no guarantee that the block and spot approach will provide the lowest average price.[53]

The second survey presented in the 2015 Draft Plan was conducted by CNT Energy in 2006,[54] several years before any significant residential switching (or even product offerings) had yet occurred. This survey was conducted on a random sample of ComEd and Ameren residential customers, and was designed to gauge the respondents' interest in "fixed" or "variable" electric rates. 17% of the respondents were definitely interested in a fixed rate, 34% were probably interested in a fixed rate, and roughly 40% were interested to varying degrees in a variable rate. The 2015 Draft Plan's conclusion from this survey appears to be that there may be very little interest in FPFR products because only 17% of the respondents were definitely interested in a fixed rate. However, a more likely conclusion from this survey is that there may be a healthy appetite for FPFR products. First of all, the survey results show that 17% of the respondents were definitely interested in a fixed rate and another 34% of the respondents were probably

[52] The 2015 Draft Plan did not explicitly contend that the 50% of customers who indicated a desire for "the lowest average price, even if that price changes frequently" represent those who would prefer the current block-and-spot approach. This is consistent with Figure 6-5 of the 2015 Draft Plan, which indicates that the block-and-spot approach does not have the lowest expected price.
[53] *See, e.g.*, 2015 Draft Plan at 59. ("The IPA understands that under certain adverse cases, the actual cost of a block hedging strategy could be greater than the cost of a full requirements strategy.") Although the IPA believes that these events are "unlikely," ICEA notes that block and spot providing a lower price on average is not a safe assumption.
[54] 2015 Draft Plan, at 60.

interested in a fixed rate, which together mean that over half of the respondents indicated that they were probably or definitely interested in a fixed rate (like the fixed rates over several months that FPFR products can provide). The 2015 Draft Plan also argues that "the IPA is not aware of any significant level of customer dissatisfaction in the ComEd service territory" with the current procurement and ratemaking approach,[55] and "[it] does not appear that eligible retail customers are clamoring for full requirements procurements."[56] Respectfully, ICEA believes that these claims do not justify a decision not to make a specific change to the procurement approach, such as the inclusion of FPFR products. In fact, the IPA has made multiple changes to the procurement approach in the past—including procurement of new build long-term renewable PPAs, which have contributed to a dramatic increase in eligible retail customer (and RES customer) spend on renewable resources–without having eligible retail customers that were "clamoring" for those changes. ICEA believes the role of the IPA and Commission in these proceedings is to evaluate the best strategy for meeting the statutory goals for procurement set out in the Public Utilities Act and IPA Act. The Commission has requested that the 2015 Procurement Plan further engage the NorthBridge Report as one such evaluation, and ICEA urges revisions to the 2015 Draft Plan consistent with that request.

An important distinction that the surveys and discussions of customer preferences presented in the 2015 Draft Plan do not address is that the price stability preference of the general population of customers is not the key question in determining the supply procurement approach for bundled service customers. Instead, the relevant questions pertain to the subset of residential (and/or small commercial) customers who cannot or will not access the retail market

[55] 2015 Draft Plan, at 60.
[56] 2015 Draft Plan, at 60.

for whatever reason and therefore remain on bundled service.[57] The current reality is that some small customers who need price stability may not have the time, incentive, knowledge, sophistication, or resources to elect an ARES offering that provides the price stability that they seek with competitive pricing. The IPA's 100% block-and-spot approach not only subjects these customers to greater price instability but, due to that approach's mismatch between the fixed quantities of fixed-price supply purchased and the uncertain actual load requirements, it results in deferred cost recoveries that can translate into situations in which those customers (who for whatever reason do not switch to an ARES) are effectively forced to pay for power from prior periods that they did not consume. This raises a host of policy and fairness questions which the IPA does not address. In contrast, to the degree that FPFR products are included in the procurement plan, these issues are mitigated.

2. The 2015 Draft Plan should be updated to reflect that the unique structure and history of the IPA does not prevent the IPA running an FPFR procurement

The second policy argument advanced in the 2015 Draft Plan relies on the uniqueness of having a state agency procure supply on behalf of utilities in restructured jurisdictions.[58] The 2015 Draft Plan states that "[i]t may be the case in other states that the procurement design was instituted so that utilities did not have to make procurement decisions (whose prudence would be reviewed and possibly challenged) and no agency like the IPA was available."[59] In contrast: "The IPA was specifically created by the General Assembly to '[o]perate in a structurally insulated, independent, and transparent fashion so that nothing impedes the Agency's mission to

[57] *See, e.g.*, ICEA FPFR Comments at 6.
[58] Examples of specific jurisdictions in which full requirements supply products are procured include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island, and Washington D.C.
[59] 2015 Draft Plan, at 60.

secure power at the best prices the market will bear, provided that the Agency meets all applicable legal requirements.'"[60]

ICEA notes as an initial matter that the Commission explicitly held that full requirements is a "standard product," thus allowing the IPA to consider procuring FPFR going forward.[61] Second, the purpose of creating the IPA was and continues to be to: "Develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." The NorthBridge Report provided substantial evidence that FPFR is the best way to meet this statutory goal, especially with regard to price stability. ICEA urges the IPA to put this approach to the test in Illinois by creating a limited FPFR pilot program to actually compare the procurement approaches side-by-side.

In addition, the basis for making this uniqueness argument may be the result of incomplete analysis of statements of Connecticut Regulators: A footnote to the 2015 Draft Plan language quoted above stated that: "the Connecticut PURA stated that it directed United Illuminating (UI) to procure 100% full requirements because UI lacked the capability to manage a portfolio."[62] While this may be true, the 2015 Draft Plan did not raise that the Connecticut PURA stated that Connecticut's other utility, The Connecticut Light and Power Company, *is* capable of managing a supply portfolio,[63] but the approved plan for that utility still involves procuring full requirements products for approximately 70% of its small customer load.[64]

[60] 2015 Draft Plan at 61 (internal footnote omitted.)
[61] *See* ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 94.
[62] 2015 Draft Plan, at 61 n.100.
[63] Decision, Connecticut Public Utilities Regulatory Authority, Docket No. 12-06-02, Request for PURA Review of Power Procurement Plan, October 12, 2012, at 3.
[64] Decision, Connecticut Public Utilities Regulatory Authority, Docket No. 12-06-02RE01, Request for PURA Review of Power Procurement Plan – Reopening, August 13, 2014, at 10.

Indeed, evidence from other states indicates that full requirements products are appropriate even for utilities that are deemed capable of managing their own supply portfolios.

The 2015 Draft Plan also raises an argument that combines its first two policy arguments:

> In 2006, Ameren and ComEd conducted a solicitation for full requirements contracts using a "descending clock" auction. The full requirements bids that cleared the auction had higher prices than many stakeholders and policymakers expected, and significantly increased retail rates.[Footnote] State policymakers decided that those prices did not adequately reflect customers' risk preferences.[65]

In the accompanying footnote, the 2015 Draft Plan states:

> The IPA does not wish to fully detail the story of the 2006 auction and subsequent legal and political action; suffice to say that policymakers decided the results were unacceptable and adopted a number of legislative solutions including the formation of the IPA.[66]

Respectfully, ICEA believes that the 2015 Draft Plan does not draw the correct lessons from the 2006 auction. The 2015 Draft Plan appears to argue that Public Act 95-0481 was an indictment of every aspect of the 2006 reverse auction. ICEA notes that some aspects *were* specifically foreclosed, including replacing the reverse auction approach and creating an independent agency to handle the event (rather than utilities).[67] Other aspects, such as FPFR, were not specifically foreclosed, as the Commission found in the last procurement plan approval docket by identifying FPFR as a "standard product."

As a side note, the IPA clearly understands that the original Public Act 95-0481 does not literally reflect the General Assembly setting a risk preference. If that was the case, it is surprising that the 2015 Draft Plan does not recommend procurement of 5-plus year swap contracts for up to 3,000 MW of energy, which the General Assembly specifically found would

[65] 2015 Draft Plan at 53.
[66] *Id.* at n.90.
[67] *See, e.g.*, 220 ILCS 5/16-111.5(e) (requiring sealed bids and accepting pay-as-bid methodology, thus foreclosing declining clock with a clearing price).

"promote price stability for residential and small commercial customers."[68] Aside from long-term renewable energy PPAs, ICEA is not aware of any IPA procurements for supply or hedging longer than 3 years despite this explicit legislative finding.

A better reading of why the 2006 auctions resulted in the IPA is the fact that electric rates had been artificially reduced, and then suppressed, for an extended period of time prior to the auction. Without sufficient customer education, and without a gradual transition to market-reflective rates, customers were surprised, and vocal in their displeasure. That is particularly true of Ameren "all electric" service customers, who had been receiving additional subsidies prior to this time.

3. The 2015 Draft Plan mischaracterizes FPFR as supporting only a POLR offering rather than default service

Finally, the 2015 Draft Plan concludes that the block and spot approach is correct for Illinois because:

> Many of those states [that use FPFR] also consider the default service to be more of a "provider of last resort" service, one that is available to ensure that customers have a rate to fall back on. In contrast, the IPA Act instructs the IPA to actively manage the procurement process to benefit the eligible retail customers with an attractive rate option.[69]

This statement is made without citation or reference, and ICEA (whose members operate in the states characterized by this passage) generally do not make that distinction. ICEA welcomes further evidence on this issue, but notes as a threshold matter that aside from Texas (which ICEA concedes does not have a traditional "default" rate), switching is at least comparable to and mostly less prevalent than in Illinois. To the extent that other jurisdictions have the utility

[68] *See* Public Act 95-0481, new Section 220 ILCS 5/16-111.5(k); *see also* 220 ILCS 5/16-111.5(k) and (k-5) (two requirements that the IPA procure longer-term resources "price stability")
[69] 2015 Draft Plan at 61.

procure FPFR as a POLR product, the majority of mass market customers in most of those jurisdictions still take supply from the "POLR."

## V. Conclusion

ICEA appreciates the opportunity to comment on the 2015 Draft Plan. In addition, ICEA greatly appreciates the stakeholder outreach that the IPA conducted over the past summer, allowing ICEA to both present on FPFR and submit written comments. Based on a combination of the ICEA Presentation, the ICEA FPFR Comments, and the NorthBridge Report, ICEA believes the evidence strongly points to—at minimum—a pilot program for the IPA to procure FPFR and with a block and spot approach to compare the two. This approach would be fully consistent with the Commission's interest in the direct comparisons in other jurisdictions. Unfortunately, the IPA has not elected to recommend FPFR at this time; further, it appears to ICEA that the Commission would appreciate the IPA better engaging the NorthBridge Report. Furthermore, ICEA notes that several of the policy justifications advanced by the IPA for not procuring FPFR are insufficient to support the IPA's position.

As a result, ICEA respectfully recommends that the IPA update the 2015 Draft Plan, specifically the discussion of FPFR, to:

- Establish a pilot program for FPFR consistent with the parameters that ICEA set out above;
- More fully engage the analysis and critiques from the NorthBridge Report, as requested by the Commission; and
- Remove or revise several policy arguments against FPFR.

Respectfully submitted,

Illinois Competitive Energy Association

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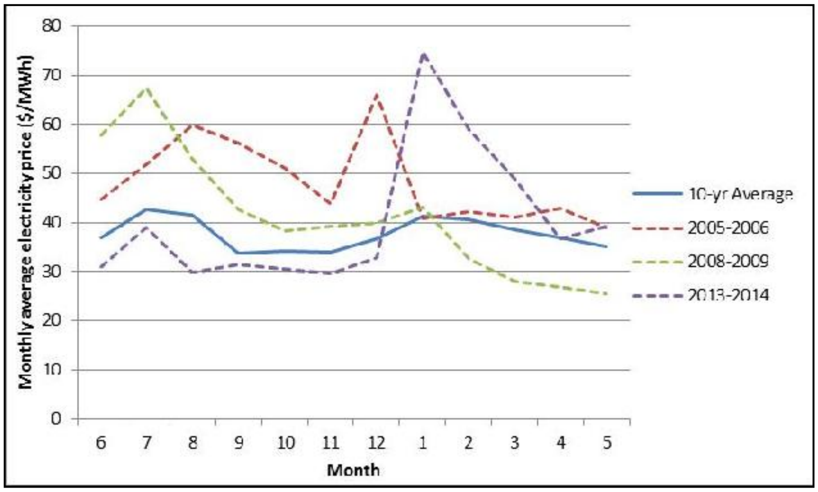
# Appendix A
# ICEA Proposed Replacement Language

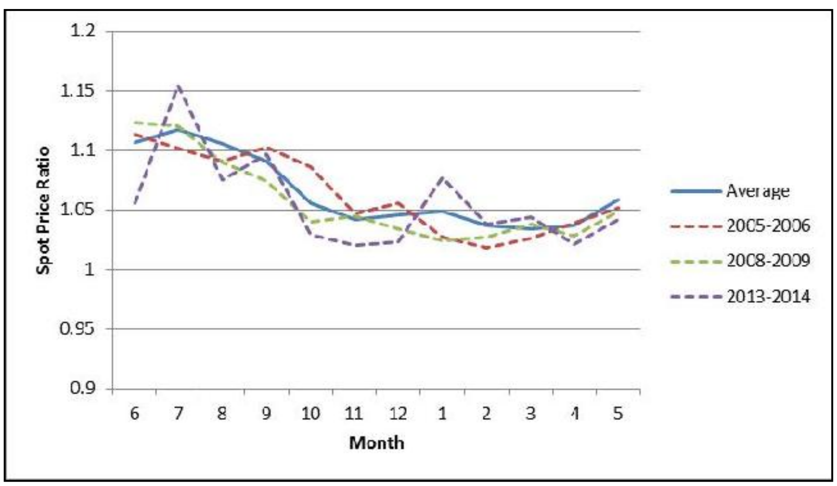
September 15, 2015

**Figure 6-2: ComEd Zone Monthly Load-Weighted Electricity Prices - 10-Year Average and Three Selected Years**




The 2014 price peak was exacerbated by the correlation of load and price, i.e., shaping. Figure 6-3 shows the monthly spot price ratio (the ratio of the load-weighted spot price to the monthly average price) in the ComEd zones for the same years as in the previous figures. It shows that the January 2014 price was enhanced by the price shape much more noticeably than was the December 2006 peak. This recent experience supports the IPA's strategy to be hedged to no less than 100 percent of expected average load during the winter months.

**Figure 6-3: ComEd Zone Spot Price Ratios - 10-Year Average and Selected Years**




## 6.6 Consideration of a Full Requirements Procurement

The current supply portfolios of Ameren and ComEd, by chosen strategy/portfolio design, do not perfectly hedge their load—primarily due to load uncertainty, the mismatch of demand and hedge profiles, and the correlation between price and load. Currently, the utilities' supply customers absorb the residual risk resulting from the utilities' portfolio design. In other words, customers self-insure the residual risk, albeit with a significant subsidy from ComEd. The effect of this risk and the subsidy becomes apparent in the application of the PEA discussed above. (ComEd subsidizes the self-insurance ~~further mitigates this impact~~ by voluntarily limiting the PEA to ±0.5 cents per kWh each month.) On the other hand, if the goal of the supply strategy/portfolio design were to provide ~~customers power~~ bundled customers who have not or will not switch the protection of ~~at~~ a fixed price over a multi-month period (one ~~to three~~ years) similar to most ARES products offered directly or through municipal aggregation, a full requirements product ~~may be~~ is a reasonable alternative for consideration. Full requirements contracts provide a form of insurance by outsourcing supply risk to a third party. Full requirements solicitations are used in several jurisdictions as a source of supply for default service load.

Various reasons are brought forth for the use of full requirements procurement:

- Full requirements procurement provides customers price insurance. One function of a competitive retail supplier is to provide price certainty. This justification presumes a policy choice that the default provider should take on that role.
- Full requirements-procured supply allows the utilities to present a more ~~appropriately represents~~ understandable and stable ~~the~~ Price to Compare, ~~since~~ because, unlike a block and spot approach with a PEA, the price will remain unchanged during a multi-month period. Full-requirements procurements ~~it~~ include~~s~~ a valuation of the uncertainty in actual pricing. Again, one must determine whether the change, which provides obvious benefits to ARES, and less clearly benefits eligible retail customers, is worth the premium.
- Full requirements pricing ~~reduces~~ virtually eliminates the potential for utilities to accumulate ~~high~~ non-trivial balances (credit or debit) to be amortized by Purchased Electricity Adjustments. When these balances have been a debit, they have been most significant for ComEd. Because ComEd voluntarily limits the size of the monthly PEA to plus or minus half a cent per kilowatt hour, it is susceptible to accumulate large uncollected (or over-collected) balances, although recent changes that allow for an annual resetting and amortization of any balances will mitigate this issue. The uncollected balances are arguably a form of price insurance that is voluntarily underwritten (without a carrying charge) by the utility.

The 2014 Procurement Plan provided guidance into the price premium (or "residual compensation") one could expect to pay for price insurance, as well as the effectiveness of that insurance in removing price uncertainty through a bottom-up model based on estimations (using monte carlo simulations) of future market prices. The 2014 Plan attempted to facilitate discussion as to whether customers would perceive the insurance as valuable enough to justify the premium. The methodology was critiqued in comments on the draft Plan, in litigation, and again in the workshop described below. Section 6.6.2 revisits the issue, explains different notions of the "premium," and presents additional cost estimates, which the Agency believes are reflective of the methodology suggested by the commenters on the follow-up questions from its June 2014 workshop on full requirements products.

The choice to buy full requirements should not depend on the absolute magnitude of a theoretical ~~that~~ price premium, but rather on whether that actual price premiums ~~is~~ are comparable to the value that consumers ~~would perceive they obtain~~ derive from by eliminating the uncertainty around the price (an evaluation that has at least a subjective component). There is no obvious formula for converting the statistics of forward-looking ~~the~~ cost distributions into dollar measures of value. That depends on customers' risk preferences and other factors. Presumably, an informed utility supply customer who values absolute price certainty would choose to take service from an ARES who offers a fixed price directly or through a comparable municipal aggregation plan.

In June 2014 the Agency held a workshop with interested parties to consider the appropriateness of a full requirements portfolio. Following the workshop the Agency issued a Request for Comments ("RFC") and posted the RFC on its website. The RFC included the following questions:

1. At the June 5th workshop some participants suggested that an analysis of a potential full requirements procurement should be for a product that includes capacity, ancillary services, etc., not just a load following energy product (as the IPA had analyzed in the 2014 Procurement Plan). Please comment on the advantages and disadvantages of this product definition, and explain

which ancillary services should, or should not, be included (e.g., active power reserves but not voltage support).

2. A participant at the workshop indicated that suppliers of fixed-price full requirements products assume price risks associated with capacity, ancillary services, etc. How would one quantify the anticipated costs of including the non-load following energy components (capacity, ancillary services, etc.) in the product described in question 1?
3. Bids for full requirements contracts include compensation for various costs and risks borne by the product supplier (i.e., "residual compensation" as described in the ICEA presentation). Please comment on what factors influence the level of this cost and how it should be estimated. Other discussions of full requirements procurement (e.g., the IPA's 2014 Procurement Plan) discuss the concept of a "risk premium." Please also comment on the differences in definition between "residual compensation" and "risk premium" and how the two concepts should be differently understood.
4. For the purposes of modeling the full requirements approach, there was discussion at the June 5th workshop about modeling for the 2015/16 delivery year an implementation of full requirements that would account for the existing block contracts as well as separately modeling (for the 2015/16 delivery year or future implementation years) an approach consisting entirely of full requirements contracts. Please discuss any limitations or adjustments to those two models, and how the existing contracts should be treated in the first model.
5. Please suggest models for how full requirements procurement could be phased into the existing ComEd and Ameren portfolios previously procured by the IPA.
6. The analysis conducted by PA Consulting for the IPA as part of the 2014 Procurement Plan included assumptions that suppliers bidding in a full requirements procurement would hedge their price exposure with forward contracts. Please provide input on what models suppliers use for estimating the costs and risks (including, but not limited to, price and load risk) that they bear as a full requirements product supplier and what inputs the IPA should consider when modeling supplier bidding behavior in a full requirements procurement.
7. To what degree, and how, could the potential benefits of procuring full requirements products (as compared to a block procurement approach) be quantified rather than qualitatively described? What are some of the relevant risk metrics that should be included in such an analysis, and how should they be compared to known procurement costs? Additionally, what are some of the inputs and variables that must be appropriately captured in order to quantitatively assess potential benefits? Are there benefits of the block procurement approach (as compared to a full requirements approach) that could also be assessed and quantified?
8. The IPA's traditional procurement approach hedges in the forward market a percentage of expected load taking into account market conditions. In the 2014 Procurement Plan, the IPA hedged 106% of average load for the summer months to mitigate shaping risk, and for the first time, the IPA is planning a fall procurement for ComEd to adjust the balance of the current delivery year supply to balance an updated summer load forecast. The goal of this second procurement is to reduce load risk. Given the legislative mandate of the Agency to "develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability," are there strategies other than full requirements procurement and the IPA's current approach that the IPA could consider for managing risks?
9. During the workshop the idea was raised that there may be ways to achieve rate stability other than utilizing a full requirements supply strategy. How could the utilities provide firm prices for a defined period through a tariff mechanism? Could the utilities adjust the PEA on an annual basis, as opposed to a monthly basis? Would a "rate stabilization account" approach add

unnecessary costs? Are there ways to achieve additional utility price/rate certainty while utilizing the IPA's current competitively-bid block procurement strategy?

10. Please provide examples of studies or other evidence that assesses or quantifies the interest of Illinois residential (and/or small commercial) customers in firm rates. To the extent available, please correlate those examples to evidence of customer choice and switching. Please also provide examples from other retail markets.

The discussion at the workshop, and the responses to the questions,[89] did not reveal a consensus or even majority opinion on most questions. Ameren and ComEd raised a variety of practical implementation concerns and were concerned that the effect of existing hedge portfolios be taken into account when estimating the risk reduction impact of full requirements contracts' risk reduction impact.[90] While the Illinois Competitive Energy Association ("ICEA") and Retail Energy Supply Association ("RESA") generally supported the notion of full requirements being a bundled product (e.g., including ancillary services and RECs in addition to energy), given ComEd's recent consideration of unbundling capacity for eligible customers, they favor excluding capacity (PLC) and network transmission (NSPL) from a full requirements product. ICEA and ComEd expressed differing views as to whether PEA fluctuations were a consequence of rate design (to be mitigated by unbundling capacity charges) or supply portfolio design. Most commenters withheld judgment on whether the value of price insurance justified its cost, although the Citizens Utility Board clearly believed that it did not. ~~Based on the comments received and the IPA's knowledge of the Illinois retail market, the IPA feels that there is no clear evidence that, as a class, retail customers who chose to take bundled service from the utilities are willing to pay a premium to mitigate the residual price fluctuations associated with the current procurement strategy.~~

### 6.6.1 Experience in Other Jurisdictions

In 2006, Ameren and ComEd conducted a solicitation for full requirements contracts using a "descending clock" auction. The full requirements bids that cleared the auction had higher prices than many stakeholders and policymakers expected, and significantly increased retail rates.[91] This was due, in part, to a 10-year rate freeze for bundled service customers, during which time market prices generally increased. Exacerbating this effect were rate design issues, particularly for all electric customers in the Ameren service territories. State policymakers decided that those prices ~~did not adequately reflect customers' risk preferences~~were not a tolerable outcome, and took action that included rate relief and foreclosing the possibility of future descending clock auctions in addition to creating a new, independent agency to oversee energy procurements.[92] Given Illinois' history, as part of considering procurement of full requirements products in a descending clock auction at a time (and within a regulatory structure) that price impacts would be steep, it is reasonable to carefully consider whether full requirements products have been successful elsewhere and developing domestic data points before committing to universal use of Full Requirements again. [IN THE ALTERNATIVE, OUT OF DEFERENCE TO THE IPA'S DESIRE TO NOT "FULLY DETAIL THE STORY OF THE 2006 AUCTION," CUT THIS PARAGRAPH ENTIRELY)

Since August 2002, New Jersey utilities have supplied the default electric load of residential and small commercial customers using full requirements fixed-price tranche contracts. The product provided by these suppliers is called the Basic Generation Service – Fixed Price (BGS-FP) product. "Default" load means the load of customers who have not switched to non-utility suppliers, called "eligible retail load" in Illinois. The contracts are procured using an annual "descending clock" auction, held the previous February. The tranche auctions are used to procure a ladder of 3-year fixed price contracts. The tariffed power price is the average

[89] Comments received are available on the IPA website under the "Energy Procurement | Plans Under Development" section.
[90] If ordered to include a Full Requirements product, the IPA will—as always—work closely with stakeholders to address legitimate implementation concerns.
[91] The IPA does not wish to fully detail the story of the 2006 auction and subsequent legal and political action; suffice to say that policymakers decided the results were unacceptable and adopted a number of legislative solutions including the formation of the IPA.
[92] *See, e.g.*, Public Act 95-0481, New Section 220 ILCS 5/16-111.5A (rate relief), 220 ILCS 5/16-111.5(e)-(f) (foreclosing descending clock auctions and requiring sealed bids instead).

of the prices of the three contracts that overlap a given year. The New Jersey auctions are well established and appear successful.

~~Larger commercial and industrial customers in New Jersey are also offered a full requirements product that is supplied using tranche auctions, but not at a fixed energy price. Instead of bidding fixed energy prices, prospective suppliers for this Basic Generation Service -- Commercial and Industrial Energy Pricing (BGS-CIEP) product bid a cost per MW, where the MW measure is the PJM capacity requirement associated with a tranche. The auction thus produces a price per MW of capacity requirement. The capacity requirement is generally about 116% of peak load. Annual load factors for BGS-FP load average around 43% in the PSEG zone. The tariffed power price is the load-weighted average PJM spot price, plus approximately $6/MWh for ancillary services, plus the auction price per MW of capacity requirement.~~

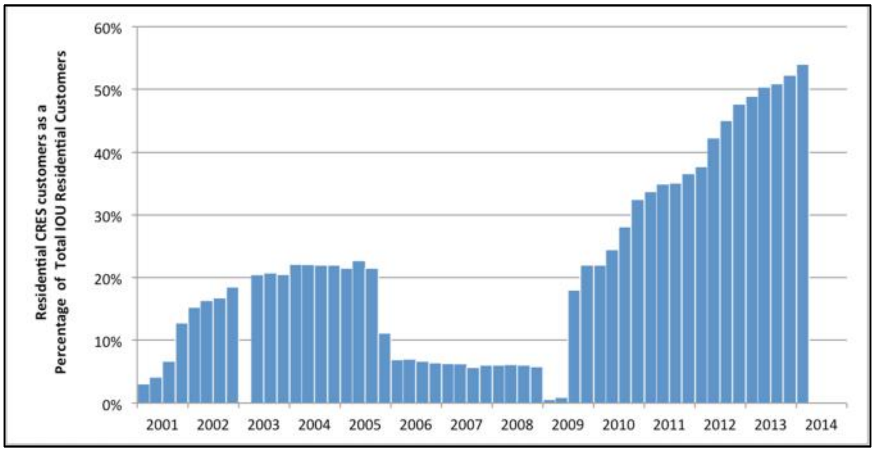
For the last eight years, utilities in Maryland, Delaware, and the District of Columbia have used a similar auction approach for purchasing electricity supply on behalf of their Standard Offer Service customers. They have separate procurements for full requirements tranche contracts, and have employed several laddering schemes and combinations of contract terms over that time. State and District regulators oversee the auctions. Maryland has formalized a process by which a procurement monitor determines in advance a "Price Anomaly Threshold" used to eliminate bids from consideration. The operation of the Price Anomaly Threshold could result in utility demand being unfilled, so a series of auctions are scheduled to meet residual need.

Utilities in several other states procure full requirements contracts for their default service via an RFP process. In Massachusetts, utilities cover the load for each customer class and zone in two overlapping 12-month contracts. For example, National Grid US (Massachusetts Electric) has residential and commercial customer groups in three zones – six load groups altogether. The company purchases two 6-month contracts for each load group: half the load is purchased 33 weeks in advance and the balance 7 weeks in advance. In Rhode Island, on the other hand, National Grid US (Narragansett Electric) purchases 90% of its residential supply through a set of staggered full requirements contracts of varying durations – 6, 12, 18 and 24 months – and 10% through the spot market. In both cases, procurement is through an RFP evaluated by the utility, not an auction.

Utilities in Pennsylvania submit individual procurement plans. Both PPL and PECO Energy have been using laddered full requirements contracts. In Connecticut, a state agency develops procurement plans for the two utilities, United Illuminating (UI) and Connecticut Light & Power (CL&P). UI has procured 100% of its default service supply through laddered full requirements contracts. CL&P has recently procured 80% of its default service supply through laddered full requirements contracts, and 20% through a portfolio managed by the utilities.

Ohio presents a case with some relevance to Illinois because of the amount of migration both into and out of municipal aggregation and the differential between market prices and default service prices. Ohio customer migration was discussed at length in the 2014 Procurement Plan. Significant customer switching occurred in FirstEnergy's territory, primarily through municipal aggregation, during the early years of the deregulation. Then in 2006, Ohio implemented rate stabilization plans ("RSPs") that held electricity prices below market levels for several years. The RSPs for the First Energy companies and Duke Energy Ohio expired at the end of 2008, and they now procure utility default service through a full requirements approach. Customer switching, driven by municipal aggregation, has grown rapidly since the expiration of the RSPs, though maybe not as rapidly as in Illinois. This history of customer switching is illustrated in Figure 6-4.

**Figure 6-4: Fraction of Ohio Utility Customers Switching to Competitive Providers**

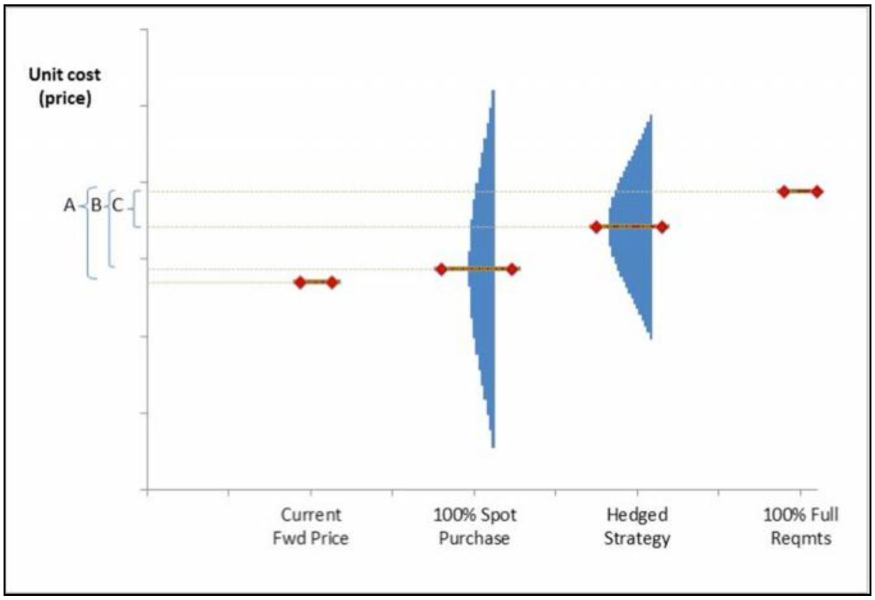



### 6.6.2 Cost and Risk of Full Requirements Contracting

Figure 6-5 is a conceptual illustration of the relationship between the cost of a full requirements hedge and the cost of supply using other hedging strategies. It is similar to related figures in Section 6 of the 2014 Procurement Plan in that it represents different supply strategies that could be used to fulfill the utilities' obligations. Most supply strategies involve some price uncertainty. In other words, when one embarks on such a strategy, the price it will ultimately produce is not known. The 100% Spot Purchase and Hedged Supply strategies are shown as rotated bell curves, symbolizing the probability distribution of cost per MWh for each (cost per MWh is the vertical axis); the horizontal mark is the expected value of the price. The full requirements strategy involves a fixed price contract and thus has no uncertainty. The current forward price is an observable value, and also has no uncertainty.

- Current Forward Price: This is the current electricity forward market price at the time that the supply strategy is decided. Because of load forecast and profile uncertainty, it is not possible to use the current forward market by itself as a supply strategy. The price is provided as a reference.
- 100% Spot Purchase: This would be a totally unhedged strategy in which all electricity is purchased from the spot market. The IPA does not recommend this approach, and is not sure at this time how it could even price this option given the utilities' tariff structures.
- Hedged Strategy: This strategy involves the use of some of the hedging products described in Section 6.2.1., with assumptions about the nature and cost of shaping.
- 100% Full Requirements: This represents the purchase of one or more fixed price full requirements contracts to meet the entire load.

**Figure 6-5: Identifying the Full Requirements "Insurance Premium"**




A full-requirements contract is a form of price insurance, and there should be a price premium associated with that.[93] One estimate of the premium, which can be computed at the time the contract is purchased, is a bottom-up approach using the amount by which the full requirements price exceeds the contemporaneous forward price, which is labeled A in Figure 6-5, with the understanding that the inevitable impact of future balancing (of an unknown magnitude) are not yet taken into account. Of course, the IPA acknowledges that it is not possible for the utilities to commit to providing bundled service at exactly the current forward price, because there are considerable potential future costs. Or, the cost of full requirements service could be broken into the actual cost of the service itself (whatever the cost of spot supply turned out to be) and residual compensation or risk premium, whose expected value is labeled B in Figure 6-5.

#### 6.6.2.1 Review of Analysis from 2014 Procurement Plan

In a competitive bidding process, one would expect that the ~~The~~ price of a full-requirements energy hedge should be based on the cost incurred and the risk managed by a provider of that hedge. In the 2014 Procurement Plan, the IPA simulated the development of a full requirements portfolio using a Monte Carlo simulation. Assuming a standardized risk management approach that may or may not be used by any individual bidder, ~~The~~ the Agency undertook the simulation to estimate the cost of a full-requirements hedge, and in particular to see how that price compared to the costs of other procurement strategies, and the value of risk avoidance. The IPA simulated full-requirements contracts of two different durations:

- A one-year contract, in which the hedge would be effective from June to May under a price that was set six weeks before delivery began (in mid-April); and
- The third year of a three-year contract, so that the hedge supplier could have been laddering its own hedge portfolio for three years.

[93] A premium for an insurance product is necessary for the supplier to be able to offer the product. From the recipient point of view, insurance is an added cost when the insurance is not used, but is likely to be a savings in total cost when the insurance is used (e.g., compare an annual auto insurance premium to the cost of replacing a totaled car).

The IPA went on to estimate the price of a full-requirements energy hedge. That estimation entailed a set of assumptions as to how a supplier would price the “insurance premium,~~.~~” again assuming a standardized risk management approach.

The IPA’s simulation (as well as the NorthBridge analysis discussed at length in litigation of the 2014 Procurement Plan, and discussed further below) indicated that full-requirements contracts would be priced at a premium relative to the expected cost of energy under the Agency’s usual procurement strategies. In other words, the Agency computed the equivalent of the price difference labeled C in Figure 6-5. The Agency’s estimated the statistical distribution of unit energy costs, and projected the amount a supplier would demand as an insurance premium based as a return on VaR (value at risk). The approximate premia (both in $/MWh and relative to the expected cost of an all-spot procurement) were as follows:

**Table 6-1: Summary of Price Premia from 2014 Report**

| | 1-year | 3-year |
|---|---|---|
| Ameren | 0.96 | 3.33 |
| | 2.8% | 9.2% |
| ComEd | 0.99 | 2.14 |
| | 3.0% | 6.0% |

#### 6.6.2.2 Critique by Commenters on the 2014 Plan

The IPA’s simulation methodology was critiqued in comments on the draft Plan, during litigation, and again in the June, 2014 workshop. The general thrust of the comments was that the simulation relied too much on assumptions about supplier behavior and not enough on the preferences and pricing revealed in full requirements solicitations elsewhere in the country. The Agency’s modeling of load and price uncertainty was also questioned.

Although the Commission did not ultimately require the IPA to adopt a full requirements approach, the Commission did request that the IPA to provide specific and detailed analyses in the 2015 Draft Procurement Plan. The Commission stated:

> The Commission appreciates ICEA's efforts in raising this issue and providing the Northbridge Report. ICEA has raised the level of discussion surrounding this particular issue, and the Commission welcomes these efforts. . . .
>
> While the Commission appreciates ICEA providing the NorthBridge Report, Staff indicates it has not had adequate time to fully analyze the Report. Similarly, while the Commission itself has reviewed the NorthBridge Report, it is not comfortable with the level of review and feedback other parties provided. Staff, for example, also expressed concerns about the level of review performed by the IPA, the AG, and CUB. . . . The Commission has endeavored to review the record notwithstanding the limited timeframe. Some of the findings in the report are compelling, including the 2012 analysis of the PECO Energy Company, which notably included a simultaneous implementation of the block and spot and fixed price full resource products as similarly proposed by ICEA in this proceeding. Additionally, the report highlights several drawbacks with the IPA’s analysis of the different procurement approaches. The Commission observes that Staff agrees with several of these critiques, and the IPA amended its analysis to address these issues. . . .
>
> For purposes of next year’s plan, the Commission directs the IPA to include a more thorough and accurate analysis of the impacts of incorporating full requirements products into its procurement strategy, including the balance of benefits-to-premium costs of those products and any significant implementation costs it believes will result from this shift in

> procurement strategy. The Commission is hopeful that this directive will allow the parties adequate time to consider this issue in the next proceeding.[94]

As noted above, the IPA took several steps to respond to the Commission Order by setting up a workshop and soliciting public comment on Full Requirements procurements. The IPA understands that the Commission also requested significant additional analysis in this Draft Procurement Plan.

In order to understand the Commission's Order, it is important to contextualize the criticisms from NorthBridge. In comments received on the 2014 Plan and in filings in the 2014 Plan approval docket, the Illinois Competitive Energy Association ("ICEA") provided an analysis by the NorthBridge Group. That analysis used a different modeling approach to consider the compensation required by a full requirements product supplier, referencing a 2012 study for the supply (including capacity and ancillary services), not just energy. (Based on comments made in July 2014, ICEA now appears to favor excluding capacity from the hedge.) NorthBridge compared the actual costs of full requirements supply to the expected costs of two different hedging strategies using block contracts—one seeking to hedge 80% of load, and one (analogous to the strategy proposed in the 2014 Procurement Plan) seeking to hedge 106%--and estimated a premia for full requirements that ranged from $0.13 to $1.69/MWH. These premia respectively represented 0.2% and 2.7% of the simulated cost of the associated hedged portfolios, and would likely represent larger fractions of the cost of a simulated "all-spot" strategy.

The analysis also included a description of "rate shock" and "supply cost surprise" metrics. "Default service rate shock" measured the ninetieth percentile of the rate change over a six-month period. The difference between this analysis and the situation in Illinois is that in Illinois, rates are fixed for a year except for the PEA, which is currently voluntarily capped (in ComEd territory), although the Agency understands that ComEd could unilaterally remove that cap at its sole discretion. ~~and for~~ ComEd may additionally be further stabilized by a rate redesign to unbundle capacity charges (consistent with ICEA's proposal to remove them from the hedge), although the IPA has not quantified the effect, if any, for capacity unbundling. "Supply cost surprise" measured the amount by which annual costs differ from the expectation three months ahead. The NorthBridge analysis reported metrics of the cost impact of very low-probability adverse events (less than 10%), whose values (for a 106% hedged block approach) were approximately $5/MWh (a 7% increase in price and very close to the cap that ComEd has imposed on its PEA). As discussed below, these cost impacts are larger than the premia that the IPA identified in reviewing NorthBridge's results. ~~Nonetheless, this point—that there are scenarios under which a block procurement could have higher costs than a full requirements procurement—has been considered by the IPA.~~

#### 6.6.2.3 Estimating full requirements based on New Jersey experience

The IPA took to heart the comments from the Commission and stakeholders encouraging the use of actual market data on full requirements pricing. The Agency also sought to minimize the use of models of price and load fluctuations. Such models can always be questioned and, especially in the case of models of customer migration, are supported by rather short historical records. The IPA analyzed auction results from the state that has been conducting full requirements solicitations for the longest period, namely New Jersey.

The IPA developed an estimate to account for the non-energy components of full requirements service, relying only on observable market data, as follows. The full requirements products provided by suppliers in New Jersey is defined to consist of "unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service, including all losses and/or congestion costs associated with the provision of such services, and such other services or products that a Supplier may be required, by PJM or other governmental body having jurisdiction, to provide in order to meet the Supplier Responsibility Share under this Agreement." For that,

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[94] ICC Docket No. 13-0546, Final Order dated December 18, 2013 at 94-96 (emphasis added, internal citations omitted).

the BGS-CIEP suppliers are paid the auction price (per MW of capacity requirement), plus the cost of network transmission service, plus the load-weighted PJM spot price for energy, plus \$6/MWh. This produces a tariffed price that fluctuates with the wholesale cost of energy.

BGS-FP suppliers provide the same product as do BGS-CIEP suppliers (unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service), but at a fixed price under three-year contracts. Therefore the price of BGS-FP supply should equal the expected price of BGS-CIEP service, plus a premium (or residual compensation) for price insurance. In other words, the following equation should hold:

BGS-FP price = expected PJM spot price + \$6/MWh + transmission rate + BGS-CIEP price
+ price insurance premium.

Rearranging, the price insurance premium can be estimated as:

Price insurance premium = BGS-FP price - expected PJM spot price - \$6/MWh
- transmission rate – BGS-CIEP price

All these values are available from the New Jersey auction results, except the expected PJM spot price. It can be approximated by the energy futures price as of the BGS auction, adjusted for the historic relationship between load-weighted and average prices (the multiplier is somewhere between A and B in Figure 6-5).[95]

**Table 6-2: Premium for price insurance derived from New Jersey auction data**

| | PSE&G | | | JCP&L | | |
|---|---|---|---|---|---|---|
| | **2009-2012** | **2010-2013** | **2011-2014** | **2009-2012** | **2010-2013** | **2011-2014** |
| **BGS-FP price (\$/MWh)** | 103.72 | 95.77 | 94.30 | 103.51 | 95.17 | 92.56 |
| **- Expected spot price** | -74.11 | -62.85 | -56.25 | -72.94 | -58.67 | -52.80 |
| **- Ancillary service price** | -6.00 | -6.00 | -6.00 | -6.00 | -6.00 | -6.00 |
| **- OATT transmission rate** | -6.01 | -7.58 | -10.33 | -4.85 | -4.95 | -4.90 |
| **- BGS-CIEP price** | -17.56 | -15.23 | -19.45 | -19.65 | -16.70 | -20.76 |
| **Estimated premium (\$/MWh)** | 0.05 | 4.11 | 2.27 | 0.07 | 8.85 | 8.10 |
| **Estimated insurance premium (% of expected spot)** | 0% | 7% | 4% | 0% | 15% | 15% |

Table 6-2 provides evidence that full requirements contract prices include a price insurance premium of several dollars per MWh. (Appendix F provides details of the methodology and calculations used to estimate the insurance premium).

The variability in the estimated premia may be due to the uncertainty around suppliers' forecasts of the BGS-CIEP price and the OATT transmission rate. The BGS-CIEP price is primarily determined by the cost of capacity; at the time of the BGS-FP auction, the PJM RPM Base Residual Auction ("BRA") for the first two years covered by the BGS-FP contract has already been held, but capacity pricing for the third year is still uncertain. The OATT transmission rate for JCP&L has been constant for several years, but the rate for PSE&G has been rising. Table 6-2 is based on the assumption that bidders will accurately forecast the transmission rate. Winning bidders may well not have known about the rate increases, or underestimated them. If the BGS-FP is

[95] Price difference A is based on the forward price without load-price correlation; price difference B is based on the expected spot prices including the impact of migration as well as load-price correlation (and possibly other uncertainties whose net impacts are anticipated to be small). These price differences both compare full-requirements service to some alternative form of energy procurement, and so are representations of the full requirements premium.

based on underestimates of the transmission rate, the embedded insurance premium would be larger than indicated in Table 6-2, reducing the difference between the estimates for PSE&G and JCP&L.

#### 6.6.2.4 Review of estimates based on Pennsylvania experience

The NorthBridge comments discussed earlier referenced an analysis conducted in conjunction with a regulatory proceeding in 2012. The Agency takes note also of a subsequent analysis by NorthBridge that formed the basis for testimony in a 2014 proceeding before the Pennsylvania Public Utilities Commission. That study reviewed imputed residual compensation levels from past PECO full requirements procurements, presented in Figure 6-6~~Figure 6-6~~. The testimony includes an analysis of the specific cost components of prior PECO procurements and residual compensation is defined as what is "required by suppliers to cover the other costs and risks that I did not individually quantify."[96]

**Figure 6-6: PECO Residual Compensation[97]**

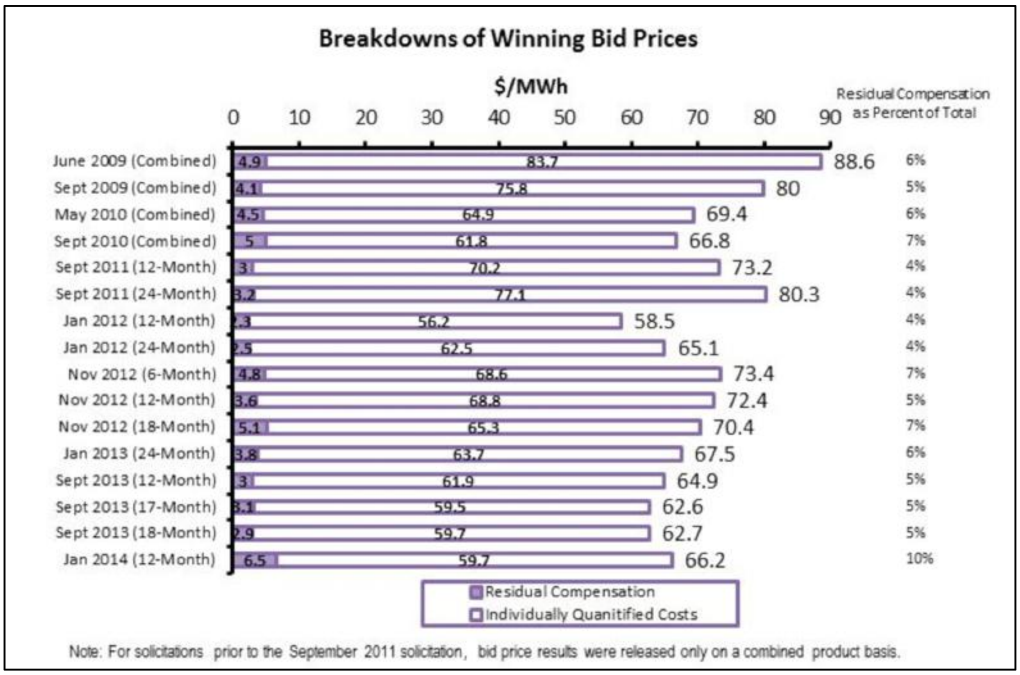



Figure 6-6~~Figure 6-6~~ also shows additional costs of several dollars per MWh for full requirements service, in line with the other estimates provided herein. There is a notable increase in residual compensation in the January 2014 procurement. The testimony notes that this procurement was coincident with the price increases associated with the so-called polar vortex. Perhaps the events of 2014 indicated to suppliers that they had been underestimating, and hence underpricing, the commitments they were taking on.

The models presented in the 2014 and 2015 Procurement Plans, the model used the NorthBridge study used to support ICEA's comments on the 2014 Procurement Plan, as well as NorthBridge's testimony elsewhere, present a range of methods and estimates of the additional costs associated with full requirements contracts. All of them indicate that full requirements prices generally include a premium relative to expected portfolio costs. However, that premium is a reasonable amount and is of a magnitude that the Agency believes does not foreclose consideration of a full requirements product. In fact, the Agency notes that the top decile costs

[96] PECO Energy Company Statement No. 3, Direct Testimony of Scott G. Fisher at 12. Docket No. P-2014-2409362, March 10, 2014.
[97] Id. at 18.

under the IPA's current hedging strategy would far exceed these prices, showing that the insurance effect is in fact quite valuable.

The IPA understands that under certain adverse cases, the actual cost of a block hedging strategy could be greater than the cost of a full requirements strategy. ~~Extreme adverse outcomes are correspondingly unlikely~~This, the Agency understands, is precisely the value of price insurance. Although that is not the only benefit of fixed price full requirements products (virtually eliminating the PEA, easier to understand, customers better able to budget), the Agency understands it is a significant one even in years that, retrospectively, it turns out that a block and spot approach would have produced a lower price. ~~Nevertheless, the IPA's current hedge strategy has been carefully designed to provide a reasonable level of insurance against price spikes, given that the entire expected load will be covered by fixed-price hedges.~~

~~An adverse case of concern would be a large volume of price-induced customer migration. Currently, high migration volumes would most likely be associated with the expiration of municipal aggregation contracts and return of those customers to bundled service after the IPA's procurement volumes are set. The IPA monitors the energy markets regularly to understand the factors that drive customer behavior (for example – price, product, regulations, the environment, etc.) and to anticipate and mitigate such potential return to service. Accordingly, the IPA has recommended a hedging strategy that mitigates load migration risk. The implementation of the fall procurement event is the direct result of the need to mitigate the risk of load migration associated with the expiration of large municipal aggregation contracts.~~

~~Finally, just as adverse outcomes can increase ratepayer costs, supportive outcomes can reduce them (as is being experienced by Ameren customers in the summer of 2014). Full requirements service would be priced at an expected-cost premium (nobody refutes this fact), meaning that under full requirements service customers would not receive the price reduction benefits of likely favorable cases. The nature of an expected cost premium is that in most scenarios, customers pay more.~~

#### 6.6.2.5 ~~How Much do Customers Value Price Insurance?~~Valuing Price Insurance via Pilot Program

There are a variety of potential policy arguments for full requirements. But, do customers want to pay a premium for price stability? The IPA had hoped that in response to its request for comments it would receive new information on customer willingness to pay for various rate options, and while a few commenters offered some thoughts on the issue (CUB stating an emphatic "no," while ICEA argued that there was appetite), they did not provide clarity. Where there is research on the subject, that research has tended to focus on interest in dynamic pricing, pre-paid services, etc. and thus not generally applicable. Those studies generally find that is there are distinct customer segments interested in various options—some customers will gladly pay a premium for certainty, other customers will gladly take extra efforts to reduce costs, and yet other customers will ration electricity in favor of more flexible payment options. ~~Quite simply, it is not clear what customers are willing to pay for in their electric rates – and even if some customers would state a clear willingness to pay such a premium, that in itself would not justify forcing all eligible retail customers to pay that premium.~~

~~One instructive recent survey came from a report on retail markets in Alberta, Canada. It found that only 13% of customers were willing to "pay a premium price, knowing that the price will not change for a year or more." In contrast 50% "want[ed] the lowest average price, even if that price changes frequently" and 36% "want[ed] a reasonable price, knowing that the price is fixed for several months." Only 2% did not know what they wanted.[98] Another study conducted by CNT Energy in 2006 of a random sample of ComEd and Ameren residential customers gauged interest in either a "fixed" or a "variable" electric rate.[99] Roughly 40% of respondents were interested, to varying degrees, in a variable rate. Only 17% were definitely interested in a~~

~~[98] "Power For the People — Retail Market Review Committee," Ministry of Energy, Government of Alberta (September, 2012) at 85.~~
~~[99] In interest of full disclosure, the Director of the IPA was employed by CNT Energy at that time and participated in the survey design and analysis.~~

~~fixed rate, and 34% were probably interested in a fixed rate. While this survey was meant to explore interest in variable rates, the relatively small percent of customers who definitely wanted a fixed rate could indicate that there is not a sizable demand for such certainty.~~[100]

~~Furthermore, the IPA is not aware of any significant level of customer dissatisfaction in the ComEd service territory with the current methodology of having rates that fluctuate slightly month-to-month due to the Purchased Electricity Adjustment. (The IPA presumes that the fairly consistent and sizable PEA credits in the Ameren service territory are even less likely to spur customer complaints because they result in savings for eligible retail customers.).~~

~~While it does not appear that eligible retail customers are clamoring for full requirements procurements in order to completely stabilize their prices, t~~The IPA acknowledges that the current procurement strategy can lead to fluctuations in the PEA. The IPA expects the volatility of the PEAs for ComEd and Ameren to decline as a result of various improvements to the IPA procurement design (and for ComEd customers, ComEd's improvement to its PEA). The mere existence of the PEA and the threat of fluctuation does make it ~~slightly~~ more difficult to compare the utility rate to an offer from an ARES. ~~But given the premia described above, the IPA does not believe that adding costs to the price paid by eligible retail customers to ease comparison shopping by customers who have left utility service is an appropriate policy goal for it to pursue under its mandates in the IPA Act.~~

The IPA has refined its block procurement approach over time, most significantly by adopting a new hedging strategy in the 2014 Plan (continued into the current Plan) that includes smaller block sizes and a second procurement in the fall. ~~This approach was adopted to address the greatest risk to the portfolio, return of load. Meanwhile, ComEd has made improvements to its PEA methodology such as capping the PEA volatility, the annual resetting of the balance, and the proposed unbundling of capacity from energy that will further reduce PEA volatility. In short, the~~ The Agency argued that its ~~IPA's~~ block procurement approach successfully meets the mandate of the IPA Act to, "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability"[101] and does not need to be changed to a full requirements approach. The Commission, in approving the 2014 Procurement Plan, was aware of those innovations when it requested that the IPA more fully review its position on full requirements and provide more analysis of NorthBridge's criticisms.

~~Although many other states with retail competition conduct full requirements procurements, the IPA does not believe this alone is a compelling reason to change course. Notably, not one of those states has a procurement process comparable to Illinois. The IPA was specifically created by the General Assembly to "[o]perate in a structurally insulated, independent, and transparent fashion so that nothing impedes the Agency's mission to secure power at the best prices the market will bear, provided that the Agency meets all applicable legal requirements."~~[102] ~~It may be the case in other states that the procurement design was instituted so that utilities did not have to make procurement decisions (whose prudence would be reviewed and possibly challenged) and no agency like the IPA was available.~~[103] ~~Many of those states also consider the default service to be more of a "provider of last resort" service, one that is available to ensure that customers have a rate to fall back on. In contrast, the IPA Act instructs the IPA to actively manage the procurement process to benefit the eligible retail customers with an attractive rate option.~~

[100] ~~Docket No. 06-0691 (cons.), CUB Exhibit 1.0 (Rebuttal Testimony of Christopher C. Thomas) at 12-13.~~
[101] 20 ILCS 3855/1-5(A).
[102] ~~20 ILCS 3855/1-5(G).~~
[103] ~~For example the Connecticut PURA stated that it directed United Illuminating (UI) to procure 100% full requirements because UI lacked the capability to manage a portfolio. Connecticut Public Utilities Regulatory Agency, Decision in Docket 12-06-02, October 12, 2012, p. 2.~~

~~In light of the analysis above, the Agency has declined to include a full requirements procurement in its 2015 Procurement Plan.~~

The Agency understands and appreciates the Commission's directive to study actual market data. As a result, the IPA proposes a four-year pilot program, restricted to the ComEd service territory, under which the IPA will procure full requirements products side by side with procuring using block products. This will allow the Commission and all stakeholders (and the Agency) to have a data-driven discussion about the costs and benefits of full requirements products. Although the Agency remains skeptical based on its forward-looking bottom-up model that full requirements will best satisfy the requirements of Section 16-111.5(d)(4) of the Public Utilities Act, the IPA understands and appreciates the inherent value in having actual numbers to drive a debate that is determined in large part by objective measures.

In order to have a sufficiently apples-to-apples comparison, the IPA recommends that 25% of total load be procured this year for the 2015-2016 delivery year, continuing on in the same fashion each of the next three years for the procurement immediately preceding the delivery year. The IPA wil adopt ICEA's recommendation that, rather than assigning block supply under contract to each full requirements supplier, that the IPA will have a separate "block procurement" tranche (consisting of 75% of load) in addition to each of the full requirements tranches (which together will total 25% of the load).

The IPA is cognizant that there is limited time available between the Commission's eventual order in the approval docket and the first scheduled procurement for full requirements products. Although the IPA is confident in its Procurement Administrator, ICEA welcomes feedback from stakeholders about standard terms and conditions for the full requirements procurement.

## 6.7 Demand Response as a Risk Management Tool

The discussion above has been focused on traditional energy and capacity supply products. As described more fully in Appendix C (which describes the ComEd load forecast), demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized expected case peak load, on days when the weather is hotter than normal. Demand response programs do not affect the weather-normalized load forecast. The programs are supply risk management tools available to help assure that sufficient resources are available under extreme conditions. PJM has a functional capacity market that includes dispatchable demand response as a resource. To the extent that demand response programs receive "capacity credit", PJM pays for this capacity based on the price from the capacity auctions and the proceeds are primarily used to fund payments to the responding customers.

In the case of Ameren, MISO provides the ability for demand response measures to contribute to reducing supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat DR and EE resources similarly to other capacity providing resources for operational planning purposes. MISO Module E permits LSEs to net the effects of DR and EE resources from their coincidental peak and will credit these resources with the equivalent number of Zonal Resource Credits ("ZRCs").

In its 2014 Procurement Plan, the IPA tested the impact of Demand Response Resources on energy costs. The impact on energy costs for non-participating customers appeared small and there appeared to be no additional risk reduction.

Section 7.5 of this plan provides details and additional discussion regarding demand response resources for both ComEd and Ameren. Section 7.1 includes a discussion of a proposed "Energy Efficiency as a Supply Resource" procurement. This proposal is not a demand response product in the narrow sense of a product that reduces capacity obligations but rather is a procurement that focuses on covering peak hours through demand side resources.

**Comments Pursuant to Section 16-111.5(d)(2) of the Public Utilities Act**
Illinois Competitive Energy Association

# Appendix B
# NorthBridge Report

September 15, 2015

# Merits of Incorporating Fixed-Price Full Requirements Products in the Illinois Power Agency Plan

**Scott G. Fisher**
**The NorthBridge Group**

**September 16, 2013**

# Table of Contents

# I. Executive Summary

## A. Introduction

In restructured jurisdictions in which customers have open access to the competitive retail electricity market, two types of supply procurement approaches generally have been employed for residential and small non-residential "default service" customers.[1] These two supply approaches are the fixed-price full requirements ("FPFR") product approach and the block-and-spot approach.

The FPFR product approach involves procuring FPFR products on a competitive basis to satisfy the default service supply needs, with each FPFR product obligating the seller of the product to satisfy a specified percentage of all of the default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. The seller is paid a predetermined price per megawatt-hour for this service. Embedded in the prices bid to supply FPFR products is a monetization of the costs and risks borne by the supplier for providing fixed-price guarantees for load following service, and the lowest-price FPFR product suppliers are selected on the basis of lowest price through the competitive solicitation process.

Instead of adopting the FPFR product approach, Illinois has adopted the block-and-spot approach to obtain its energy supply for its "eligible retail customers" (i.e., for its residential and small non-residential default service customers in service classes that have not been declared competitive and who take service from their utility's bundled service rate).[2] The block-and-spot approach involves managing an energy supply portfolio for default service customers consisting of fixed-quantity, fixed-price block energy products supplemented with spot market transactions to cover the mismatch between the fixed quantities of fixed-price supply purchased and actual load requirements. The block-and-spot approach avoids the customer payment of some embedded "premiums" in product prices because the products underlying the block-and-spot approach do not require suppliers to provide insurance against a host of adverse market and regulatory risks; but at the same time, the block-and-spot approach can result in significant unintended adverse consequences for customers if actual market outcomes differ materially from expectations, such as through unexpected swings in load and/or market prices.

In several states, considerable time and effort has been spent debating and modeling the pros and cons of alternative approaches to procure default service supply for smaller customers. Typically, key policy questions for regulators have included:

[1] "Default service" is a general term used to denote the supply service provided to customers who do not elect service from an alternate retail electric supplier, customers who initially elect service from an alternate retail electric supplier but later choose to return to service provided by the distribution utility, and customers who are switched back to service provided by the distribution utility due to failure of their alternate retail electric supplier to provide electric service.

[2] These customers will be referred to as "bundled service" customers.

- Are the risks of unanticipated market prices and loads, which are borne by customers under the block-and-spot approach, large enough to be concerned about them?

- Does the added price protection that FPFR products offer customers justify the compensation required by FPFR product suppliers to bear the risks of unanticipated changes in market prices and loads?

- How will the supply procurement approach influence default service rates and the extent to which they provide transparent price signals for customers to confidently make economic service decisions?

### B. Key Findings

Over time, as the pricing of FPFR products has evolved and the adverse risks to customers of not using FPFR products have been better understood, most restructured jurisdictions have concluded that the risks of unanticipated market prices and loads, which are borne by customers under the block-and-spot approach, are large enough to be concerned about and have chosen to rely predominantly on FPFR products for their default service supply for smaller customers. These jurisdictions believe that the added price protection that FPFR products offer justify the compensation required by FPFR product suppliers to bear the risks of unanticipated market prices and loads to the benefit of customers. In fact, the FPFR product approach has become by far the most prevalent and favored form of default service supply procurement for smaller customers in restructured jurisdictions, and there are many sellers willing to compete on the basis of lowest price to provide FPFR products. Examples of specific jurisdictions in which full requirements supply products are procured include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island, and Washington D.C. In fact, numerous state public utility commissions have explicitly recognized the comparative benefits of the FPFR product approach.

A straightforward analysis shows that customers in Illinois have indeed been subject to costs and unnecessary adverse financial risks under the block-and-spot approach, due to the inability of this approach to match the quantities of fixed-price supply purchased with the uncertain load requirements. For example, the additional energy supply cost embedded in the June 2012 – May 2013 ComEd PEP supply charges, due to the fact that the supply products under the block-and-spot approach could not "follow the load" like FPFR products do, was approximately $9/MWH. Furthermore, the PEA, which is an additional supply charge that bundled service customers incur to cover additional unanticipated supply costs, was on average almost $3/MWH during this time. Also, the significant monthly variations in the PEA that are necessitated by the supply/load mismatches under the block-and-spot approach distorted the bundled service rates against which alternative electric retail suppliers ("ARES") competed. These bundled service rates with lagged PEA adjustments are problematic because they do not allow for transparent benchmarks for customers to compare with ARES product offerings and to confidently make economic retail service decisions. Recent ComEd data also indicates that, in a period spanning only three months, the block-and-spot approach caused almost $100 million in additional costs that must be deferred for recovery from customers in future periods. Indeed, the block-and-spot approach's inevitable mismatch between the fixed quantities of fixed-price supply purchased and the uncertain load requirements can cause significant unexpected costs that must be deferred for recovery in future periods, which can have detrimental effects on both customers and retail competition in general. For example, since the recovery occurs in future periods, customers sometimes can bypass payment for power procured on their behalf by switching off of bundled service between the time that the cost is incurred and the time that it is recovered. Similarly, customers who switch to bundled service effectively may be required to pay for power from prior periods that they did not consume. This creates issues of cross-subsidization between customers. Given the uncertainty about future market prices and future bundled service load levels, especially with over half of the current Illinois municipal aggregation contracts expiring during the 2014-2015 procurement year, the supply/demand mismatches and their associated effects on costs could be especially large under the block-and-spot approach.

In contrast, to the extent that FPFR products are utilized in a bundled service supply portfolio, these products protect customers from the significant adverse financial risks and rate instability associated with the block-and-spot approach. The FPFR product approach also accommodates customer switching better than the block-and-spot approach does, because issues pertaining to rate distortion, rate instability, and deferred cost recovery are not triggered by customer switching with the FPFP product approach, like they are with the block-and-spot approach. The FPFR product approach also harnesses the full benefits of wholesale competition. Specifically, unlike the situation under the block-and-spot approach, FPFR product bidders compete on the basis of the lowest price to satisfy all aspects of the default service customers' load requirements, including the portfolio management function.[3] In contrast, under the block-and-spot approach like that currently adopted in Illinois, portfolio management decisions are made through an annual regulatory process, so there is no competition among qualified parties to determine the most cost effective ways to develop and manage supply portfolios that allow for the least-cost provision of fixed-price bundled service for customers.

The 2014 Draft IPA Plan[4] presents an analysis designed to compare the FPFR product approach with the block-and-spot approach. Based on this analysis, the Illinois Power Agency ("IPA") states, "The analysis in Chapter 6 indicates that full requirements products do not have a great cost or risk advantage over a block-based strategy, when the current hedge portfolios are taken into account...The IPA is not prepared to recommend the use of full requirements products."[5] The analysis performed by the IPA may be useful to provide some insight regarding which permutations of the block-and-spot approach expose customers to more risk than others, and therefore it may be useful to help assess which permutations of the block-and-spot approach are more or less attractive than others. But, the analysis contains significant shortcomings that make it unable to provide useful information regarding the relative merits of the FPFR product approach as compared to the block-and-spot approach. As a result, conclusions drawn from the IPA's analysis regarding the attractiveness, or lack thereof, of including FPFR products in the IPA Plan should be disregarded. Significant shortcomings of the IPA's analysis, which

[3] FPFR product suppliers have the responsibility for continuously satisfying the uncertain and constantly changing supply requirements at the agreed-upon price, and therefore must manage the associated costs and risks through their supply portfolio decisions.

[4] 2014 Illinois Power Agency Electricity Procurement Plan Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts for Public Comment, August 15, 2013. ("2014 Draft IPA Plan")

[5] 2014 Draft IPA Plan, at 89-90.

invalidate its findings regarding the FPFR product approach relative to the block-and-spot approach, include the following:

- <u>The IPA's analysis is based on an unsupported and untested assumption about FPFR product pricing.</u> Instead of relying on any actual FPFR product price data, the IPA arbitrarily assumes that the price required by FPFR product suppliers will be enough to cover their expected unit costs across a spectrum of simulated scenarios, plus an additional amount that is up to 0.3 times the difference between the expected unit cost and the unit cost that the suppliers would incur in one of the more extreme scenarios modeled. In fact, the IPA recognizes that its analysis may not reflect actual FPFR product pricing. Given these facts and the arbitrary nature of the IPA's assumption regarding FPFR product pricing, the IPA's analysis cannot be relied upon to provide reasonable estimates of the pricing of FPFR products in Illinois.

- <u>The IPA's analysis omits or underestimates various drivers of costs and risks that are directly borne by customers under the block-and-spot approach, but from which the FPFR product approach provides protection for customers.</u> As a result, in its analysis and comparison of the two approaches, the IPA underestimates the risks to customers under the block-and-spot approach. Such omissions or underestimations include:

    - <u>The IPA's analysis underrepresents bundled service load uncertainty.</u> In far more than half of the scenarios modeled by the IPA in its analyses, the IPA assumes that the actual monthly on-peak and off-peak average load levels exactly match forecasted values. Furthermore, in the remaining minority of scenarios, the IPA caps the degree to which actual loads may deviate from the forecasted values. This is troubling, especially considering that actual outcomes regarding factors that contribute to supply cost risks recently have fallen outside of IPA-predicted extremes. Due to all of these facts, the IPA has very likely underestimated the uncertainty about future load levels, and therefore it has underestimated the related costs and risks that customers directly bear under the block-and-spot approach.

    - <u>The IPA's analysis does not capture the reality that the forecast of load for a given delivery period may be higher at one point in time leading up to the delivery period, lower at another point in time leading up to the delivery period, etc. This artificially limits the spectrum of possible scenarios and</u> financial risks to customers under the block-and-spot approach which are included in the IPA's analysis.

    - <u>The IPA has made an unsupported key assumption about the relationship between market price movements and bundled service load levels, which is an important driver of the costs and risks that customers directly bear under the block-and-spot approach.</u> The IPA's unsupported assumption of a relatively weak correlation between average market price levels and bundled service load levels easily may misrepresent the true relationship, especially in light of statements made by the IPA implying a recognition of a strong relationship between market prices and bundled service loads.[6]

- <u>The IPA's analysis ignores the cost and risk resulting from uncertainty with respect to hourly load and spot price patterns during the intra-month on-peak and off-peak periods.</u>

- <u>The IPA's analysis appears to omit the risk that the costs of any of the non-energy supply components vary from expectations.</u>

- <u>The IPA's analysis of the FPFR product approach involves a melding of various simulations, in which distributions of various outcomes under different simulations are somehow combined, as opposed to a performing a straightforward simulation of the FPFR product approach.</u> It is unclear whether inaccuracies, distorted results, or misrepresentations of the most reasonable and appropriate ways to integrate the FPFR product approach into the existing supply mix, are introduced by this piecemeal approach or by any other aspects of the IPA's analysis. It is very possible that such problems exist in the IPA's results, as the results appear counterintuitive at times.

- <u>The IPA's analysis of the FPFR product approach relative to the block-and-spot approach does not address all of the aspects of costs and risks that are of concern with respect to a given bundled service supply approach.</u>

- <u>The IPA does not appear to consider the most likely way that FPFR products would be defined and integrated into the existing supply portfolio.</u> Specifically, the IPA's rejection of the concept of integrating FPFR products into the supply portfolio is at least in part based on an assumption that the FPFR products would be defined in such a way that the FPFR product suppliers would be required to serve only the residual load requirements (above the volumes of the supply products already purchased). Because this approach would require the FPFR product suppliers to bear the entire load risk while only serving the residual load, the IPA concludes that the FPFR product prices could be high and that it would be difficult to assess their reasonableness. However, this conceptualization of how the FPFR products would be defined and integrated entirely overlooks the arguably more manageable way to define the FPFR products and integrate them into the supply portfolio. Specifically, the FPFR products could be designed like those in almost every other jurisdiction, in which the FPFR product suppliers must serve a (pro-rata) cross-section[7] of the entire actual load requirement. The remaining cross-section would be supplied through the block-and-spot approach (i.e., the residual load requirements, above the supply product quantities, would be satisfied through purchases and sales in the spot market, as they are now). This method of integrating FPFR products, which apparently was overlooked by the IPA, effectively separates the load

[6] Furthermore, simply changing the relevant numerical assumption in the IPA's analysis would not fix this problem with the IPA's analysis. The IPA's analysis fails to capture the basic causal relationship between market prices and retained loads for price-sensitive customers.

[7] Technically speaking, in some other jurisdictions, the FPFR product's supply requirement may be net of a very small amount of separately contracted supply.

> into two portions: one that is entirely supplied by FPFR products and one that is entirely supplied by the block-and-spot approach. This method has several benefits relative to the method suggested by the IPA. First, it should be fairly simple to implement. The portion of the load to be supplied by FPFR products would be a fixed percentage share of the entire actual hourly load requirement and therefore it would allow for FPFR products that are structurally similar to those solicited elsewhere. Meanwhile, the portion of the load to be supplied by the block-and-spot approach could operate exactly like that proposed by the IPA, but the overall supply quantities would be scaled down to accommodate the portion of the load that is supplied by FPFR products. Second, by not requiring FPFR product suppliers to bear the entire load risk while only serving a "residual" load ("above" or "on top of" block products), the prices of the FPFR products would be reduced. Third, because the FPFR products would supply a cross-section of the load, their prices could more easily be compared to expectations about the market costs of various components of the FPFR supply obligation as of the times of the FPFR product solicitations.[8]

Robust quantitative analysis based on actual market data from a region in which the block-and-spot approach and the FPFR product approach simultaneously had been implemented indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is reasonable. Specifically, the analysis indicates that, in comparison to the FPFR product approach, the increases in risk borne by residential customers under the block-and-spot approach are not balanced by a proportionate decrease in the expected default service rate level. Admittedly, the costs and risks borne by FPFR product suppliers may vary from one jurisdiction to the next. Generally speaking, the higher the risk of unanticipated market price or load movements, the greater the value of the protection against adverse risks that the FPFR products provide. Indeed, insurance is most valuable (and has the highest purchase price) when the risk of adverse unanticipated outcomes is high, such as is the case in Illinois, in which the possibility of large swings in bundled service load exists, and these swings can easily make a block-and-spot approach "too long" or "too short" in terms of its intended hedging targets. If uncertainty about customer switching is higher in Illinois, then the compensation required by Illinois FPFR product suppliers to bear resultant higher costs and risks to the benefit of customers will be higher, but the costs and risks that would be borne by Illinois customers under the block-and-spot approach also will be higher, so this does not justify rejection of the FPFR product approach in Illinois.

Given these facts, the prospect of continuing with a full block-and-spot procurement approach is particularly troubling, especially in light of the Competition Act's finding that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price

[8] Any such assessment must consider expectations as of the times of the FPFR product solicitations. It would be inappropriate to pass judgment on any procurement approach based solely on a measurement of its costs during the single market scenario that unfolded in the past; instead, we should assess how the approach would perform in the future, with a consideration for, and an informed understanding of, the many different possible market scenarios that could unfold. Similarly, people generally do not decide to reject health insurance for their family because they didn't get sick in a particular past period.

stability."[9] As has been explained and supported with evidence from recent Illinois supply costs, the block-and-spot approach can result in additional costs, risks, instability, and perverse outcomes for customers. In contrast, the FPFR product approach protects customers from these risks. The IPA's conclusions about the relative merits of these two supply approaches are invalidated by significant shortcomings in its analysis and its apparent failure to consider the most likely way that FPFR products would be integrated into the existing supply portfolio. However, an analysis that pertains to a region in which both supply approaches simultaneously had been implemented indicates that FPFR product pricing is reasonable given the costs and risks that FPFR product suppliers directly bear to the benefit of customers. Given this evidence of the benefits of FPFR products and the fact that these benefits are widely recognized in other restructured jurisdictions, FPFR products should be included in the IPA Plan. To the extent that these products are included, they will protect customers from the proven adverse risks of the block-and-spot approach, and more information will be gained about their pricing in the context of the Illinois electricity markets.

## II. Customers Bear Certain Costs and Risks under the Block-and-Spot Approach, but These Costs and Risks Are Shifted to Third-Party Suppliers under the FPFR Product Approach

### A. Two Supply Approaches, the FPFR Product Approach and the Block-and-Spot Approach, Generally Have Been Employed for Smaller Default Service Customers in Restructured Jurisdictions

In restructured jurisdictions in which customers have open access to the competitive retail electricity market, two types of supply procurement approaches generally have been employed for residential and small non-residential default service customers. These two approaches are the FPFR product approach and the block-and-spot approach.

The FPFR product approach involves procuring FPFR products on a competitive basis to satisfy the default service supply needs, with each FPFR product obligating the seller of the product to satisfy a specified percentage of all of the default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. The seller is paid a predetermined price per megawatt-hour for this service to compensate it for the costs and risks which it bears on behalf of customers. Typically, this compensation is embedded in the suppliers' bid prices in a competitive solicitation process with the lowest price suppliers selected, and it is a monetization of the costs and risks of providing fixed-price guarantees for load following service.

Instead of adopting the FPFR product approach, Illinois has adopted the block-and-spot approach to obtain its energy supply for its "eligible retail customers" (i.e., for its residential and small non-residential default service customers in service classes that have not been declared

[9] 20 ILCS 3855/1-5(1).

competitive and who take service from their utility's bundled service rate).[10] The block-and-spot approach involves managing an energy supply portfolio for default service customers consisting of fixed-quantity, fixed-price block energy products supplemented with spot market transactions to cover the mismatch between the fixed quantities of fixed-price supply purchased and the actual load requirements. The block-and-spot approach avoids the customer payment of some embedded "premiums" in product prices because the products underlying the block-and-spot approach do not require suppliers to provide insurance against a host of adverse market and regulatory risks; but at the same time, the block-and-spot approach can result in significant unintended adverse consequences for customers if actual market outcomes differ materially from expectations, such as through unexpected swings in load and/or market prices. The block-and-spot approach in Illinois also is accompanied by a reconciliation mechanism and deferral balance to address potential mismatches in supply revenues and costs.

In several states, considerable time and effort has been spent debating and modeling the pros and cons of alternative approaches to procure default service supply for smaller customers. Typically, key policy questions for regulators have included:

- Are the risks of unanticipated market prices and loads, which are borne by customers under the block-and-spot approach, large enough to be concerned about them?

- Does the added price protection that FPFR products offer customers justify the compensation required by FPFR product suppliers to bear the risks to of unanticipated changes in market prices and loads?

- How will the supply procurement approach influence default service rates and the extent to which they provide transparent price signals for customers to confidently make economic service decisions?

The remainder of this paper discusses these questions in the context of the Illinois electricity markets.

### B. The Block-and-Spot Approach Can Result in Additional Costs, Risks, Instability, and Perverse Outcomes, for Customers

Block products involve fixed-cost commitments that do not vary with the load obligation. Under the block-and-spot approach, the unavoidable mismatch between the fixed quantities of fixed-price supply purchased and the uncertain load requirements results in significant and unnecessary financial risks for customers, especially in an environment like the one in Illinois, in which customer migration risks are substantial. Therefore, a significant problem with the block-and-spot approach pertains to the degree to which it exposes customers to unstable and potentially excessively high rates, as well as the possibility of significantly distorted market signals that could compound the negative repercussions of this approach.

[10] These customers will be referred to as "bundled service" customers.

Moreover, under the block-and-spot approach, there is a general tendency for the effect on customer rates, due to unexpected deviations in prices and loads from expected values, to be adverse. When a utility adopts the block-and-spot approach and market prices unexpectedly decline, causing customers to exercise their option to switch to an ARES, the utility is left with an unexpectedly high portion of the default service supply portfolio being composed of above-market block contracts because the volume of block contracts does not decrease even though the uncertain default service load does decrease as customers abandon the resultant relatively high-priced default service.[11] Consequently, as market prices decline and customers switch off of default service, default service rates will increasingly reflect above-market costs, thereby causing the rates to be unavoidably high and distorted in relation to true market price signals.[12] This also creates a significant danger of a compounding and further destabilizing effect to the problem, as the higher default service rates needed to recover the above-market costs of the fixed-quantity block contracts from the fewer remaining default service customers motivate even more of these customers to abandon default service, leaving the burden of the above-market block contract costs to be borne by even fewer customers and causing the necessary default service rates to continue to climb. This can lead to a perverse outcome of rising default service rates during a period of declining market prices, especially impacting those default customers who are least likely to shop with an ARES for whatever reason. This effect is sometimes referred to as the "death spiral." In the extreme, it could become difficult to recover the costs solely from default service customers, causing customers who are not even being served through default service to pay for the stranded default service supply costs. Conversely, when a utility adopts the block-and-spot approach and market prices unexpectedly increase, causing customers to switch back to default service in order to take advantage of the resultant below-market costs of the block products, the utility then needs to make supply purchases in the now high-priced market in order to meet its load requirements, and this drives up default service rates.

Furthermore, it is critical to recognize that customer switching is not the only driver of the costs and additional risks that customers bear under the block-and-spot approach. Unexpected weather patterns, changes in customer usage patterns, plant outages or transmission line outages, fuel price shocks, unexpected economic growth levels, regulatory and legislative uncertainty, and unanticipated ancillary services costs also cause prices and loads to deviate from expected values, contributing to the types of customer-borne costs and risks under the block-and-spot approach.

[11] In fact, the utility could be left with excess supply that it would be forced to sell at a loss to be recovered from customers.

[12] Even if the level of switching is not high enough to cause the default service load to be lower than the amount of block supply procured, customers would still incur these types of costs under a block-and-spot approach; as long as the market price decline encourages any customers to switch, the default service load will be lower but the constant amount of block supply will not be lower and, as a result, an unexpectedly high portion of the default service supply portfolio will be composed of above-market contracts, having an upward effect on default service rates.

### C. The Illinois Experience Provides Evidence of Costs and Unnecessary Adverse Financial Risks Borne by Customers, as Well as Rate Distortions, under the Block-and-Spot Approach

In Illinois, evidence of the costs and unnecessary adverse financial risks for customers under the block-and-spot approach, which are due to the inevitable mismatch between the fixed quantities of fixed-price supply purchased and the uncertain load requirements, can be found in the three recovery mechanisms of bundled service customers' supply costs:

- <u>Purchased Electricity Prices ("PEP")</u> – Some of the supply costs are embedded in the PEP rates that bundled service customers must pay for their electricity supply and that are set each May for the upcoming June through May period. These prices are based on expectations of the utility's cost of supply given its existing contracts, market price projections, and bundled service load projections.

- <u>Purchased Electricity Adjustment ("PEA")</u> – Some of the supply costs are embedded in the PEA, which is an additional supply charge that bundled service customers incur to cover additional supply costs (or receive refunds) as actual supply costs vary from the anticipated values represented by the PEP. The PEA varies monthly and for ComEd it is capped at +/-$5 per megawatt-hour.

- <u>Deferred Cost Regulatory Asset</u> – Since the PEA cannot instantaneously reconcile revenues with supply costs, costs are relegated to a regulatory asset; build-ups of this regulatory asset constitute additional costs that must be recovered from customers at some later date.

A straightforward analysis of these three components of Illinois' bundled service customers' rates shows that customers in Illinois have indeed been subject to costs and unnecessary adverse financial risks due to the block-and-spot approach's inability to match the quantities of fixed-price supply purchased with the uncertain load requirements. To illustrate this, let us first investigate the recent PEP rates. Specifically, we will focus on the ComEd PEP rates established for the most recently completed June through May year, June 2012 – May 2013. The underlying cost of energy in these PEP rates is based on several inputs. One set of inputs is the prices and quantities of all previously purchased energy products with delivery periods extending into the June 2012 – May 2013 period, which namely were the ComEd swap contract with Exelon Generation, the long-term renewable generation contracts signed in 2010, the block energy products procured in the 2011 RFP, and the block energy products procured in the 2012 RFP. Additional inputs to the underlying cost of energy in the PEP rates are the load forecast, and the energy market price forecast (applied to the residual supply needs above/below the quantities of supply already contracted) which includes gross-ups for the additional cost of supplying a customer load shape rather than a constant energy quantity. While the calculations supporting the June 2012 – May 2013 PEP rates were not made public, we can closely replicate the calculation used for the energy cost underlying these PEP rates using public data. As shown in

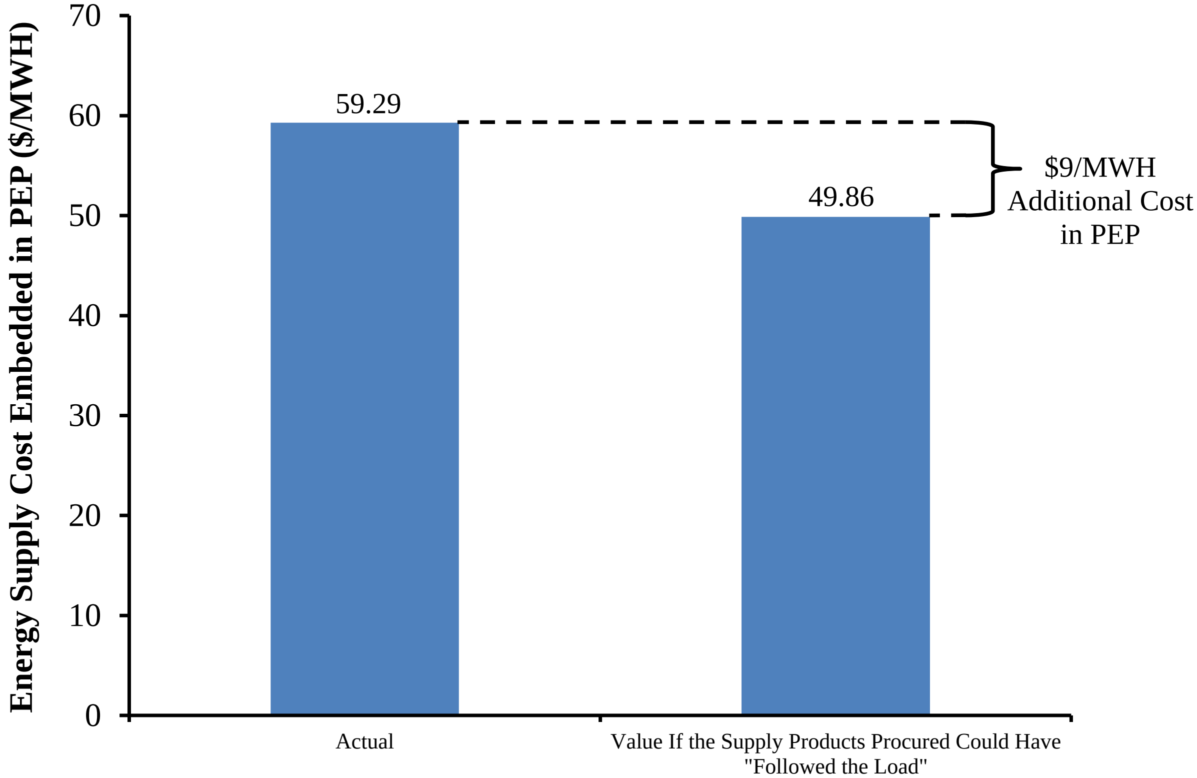
Appendix A, the overall energy cost that was built into the June 2012 – May 2013 PEP rates was approximately $59.29/MWH.[13]

While $59.29/MWH represents the overall energy cost embedded in the PEP rates, the question at hand relates to how much of this is due to the fact that the underlying block-and-spot supply approach does not have the flexibility to match the fixed-price quantities of its supply with the load, like the FPFR product approach has. In other words, how much additional cost was incurred because the fixed-price supply products procured under the block-and-spot approach do not scale their quantities, "following the load" as a fixed-price FPFR product would? In order to quantify this amount, we must identify the proportions of the load that each previously contracted energy product (for delivery during the June 2012 – May 2013 period) was targeted to provide. Specifically, based on the publicly-available and relatively contemporaneous ComEd load forecast at the time that the swap contract was signed, the swap contract was targeted to cover approximately 73% of the bundled service load during the June 2012 – May 2013 period, in a constant quantity during this time. Furthermore, based on the relatively contemporaneous ComEd load forecast at the time that the 2010 long-term renewable generation purchase was approved, this contract was targeted to cover approximately 3% of the bundled service load during the June 2012 – May 2013 period. Finally, according to the relevant IPA Plans, the block energy products procured in the spring of 2011 were designed to constitute the positive differences between previously contracted supply quantities and 70% of the forecasted monthly on-peak/off-peak bundled service loads, and the block energy products procured in the spring of 2012 were designed to constitute the positive differences between previously contracted supply quantities and the forecasted monthly on-peak/off-peak bundled service loads. While these were the targets, the forecasted load had changed by May 2012 when the PEP rates were set, and the inability of these block energy products[14] to follow the load like FPFR products do resulted in additional costs to customers. We can quantify the additional costs by comparing the $59.29/MWH embedded energy cost value described above to the value that would have resulted if the quantities of these supply contracts scaled with the changes in load, thereby "following the load." Appendix B shows this calculation. The result is $49.86/MWH. Consequently, the additional energy supply cost embedded in the June 2012 – May 2013 PEP rates, due to the fact that the supply products under the block-and-spot approach could not "follow the load" like FPFR products do, was $59.29/MWH minus $49.86/MWH, or approximately $9/MWH.

[13] Forecasted market prices were calculated as NYMEX futures prices for the Northern Illinois Hub as of the market close on April 26, 2012, with a monthly shape applied to annual price strips as necessary, multiplied by a historical ComEd Zone to Northern Illinois Hub basis factor. Market price data was provided by Ventyx / Energy Velocity. Adequate price data was not publicly available for the energy prices embedded in the long-term renewable generation contracts (which are of relatively very small quantities anyway), so it was assumed that the embedded energy prices were equal to the forecasted market prices (i.e., it was assumed that the long-term renewable generation contracts were not above-market).

[14] The swap contract is a form of a block energy contract. The long-term renewable generation contracts are not block energy contracts, but they are not load following contracts either.

**Additional PEP Costs Due to Inability of Supply Products to "Follow the Load" (ComEd June 2012 - May 2013)**




This by no means portrays the maximum extent of the additional costs that could be incurred by customers in the future; instead, this is simply real-world evidence of one part of the additional cost that was incurred during one very recent period. During this time, customers paid significantly higher PEP rates due to the inflexible nature of the block-and-spot approach, as this approach involves the use of products that do not adjust to changing load conditions. If the FPFR product approach is adopted instead, then the FPFR product suppliers will bear these costs, while protecting customers from them, and they will incorporate compensation in their product prices for bearing these costs and risks to the benefit of customers.

Evidence of the costs and unnecessary adverse financial risks for customers under the block-and-spot approach also can be found in the PEA. The PEA is an additional supply charge that bundled service customers incur to cover additional supply costs (or receive refunds) as actual supply costs vary from the anticipated values represented by the PEP. The PEA varies monthly and for ComEd it is capped at +/-$5 per megawatt-hour. Under the block-and-spot approach, on net the PEA is generally expected to be positive because of the logical positive correlation between prices and loads. For example, if market prices unexpectedly decrease after the PEP rates are set, then customers have a tendency to switch off of bundled service, leaving the utility with an unexpectedly high portion of the default service supply portfolio being composed of above-market block contracts because the volume of block contracts does not decrease even though the uncertain default service load does decrease as customers abandon the resultant relatively high-priced default service. The PEA would be adjusted to capture this positive additional cost. Similarly, the PEA would be adjusted to capture the positive additional cost if market prices unexpectedly increase after the PEP rates are set, causing customers to switch back to bundled service and forcing the utility to make supply purchases in the now high-priced market in order to meet its load requirements. As shown below, during the June 2012 – May 2013 period, ComEd's load-weighted-average PEA was $2.87/MWH.[15,16]

**June 2012 - May 2013 ComEd PEA**

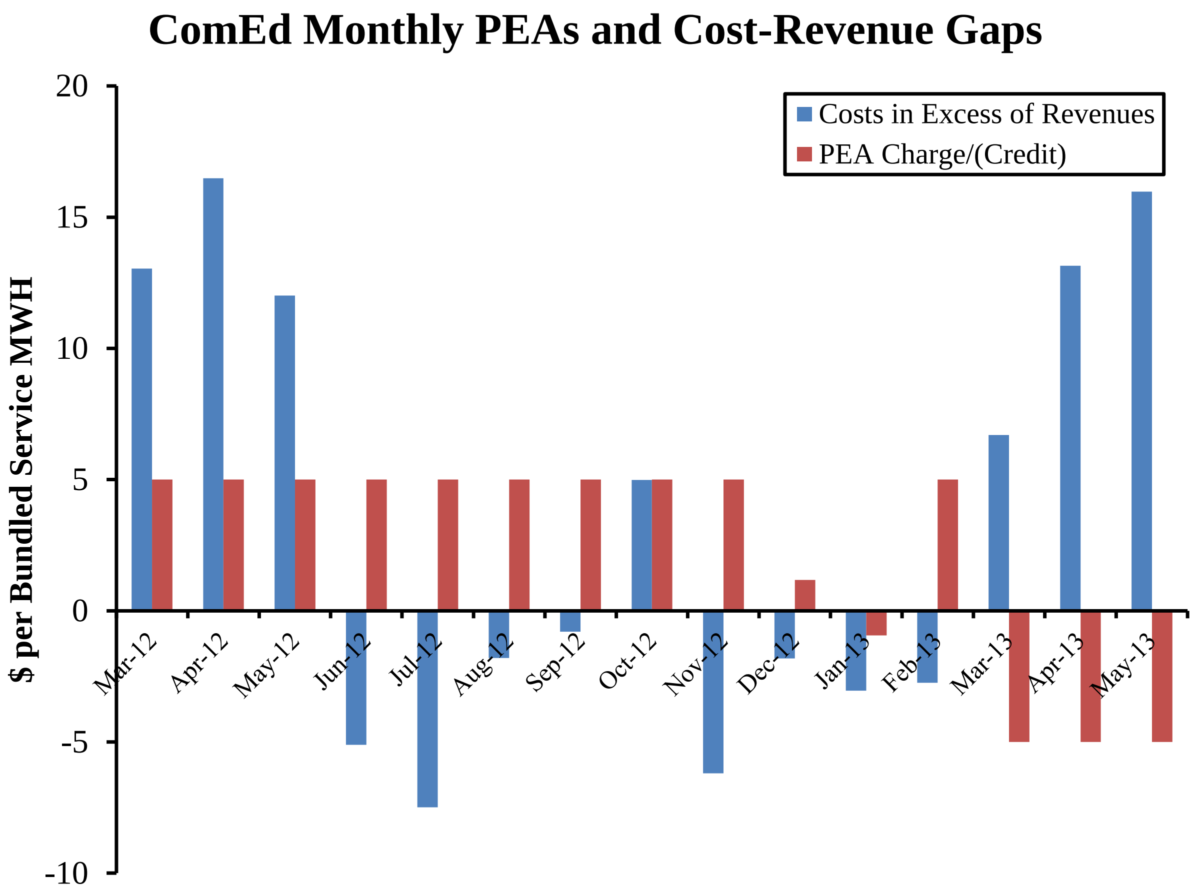
| | PEA ($/MWH) | Bundled Service Load (GWH) |
|---|---:|---:|
| June 2012 | 5.00 | 3,244 |
| July 2012 | 5.00 | 4,210 |
| August 2012 | 5.00 | 2,756 |
| September 2012 | 5.00 | 1,828 |
| October 2012 | 5.00 | 1,594 |
| November 2012 | 5.00 | 1,601 |
| December 2012 | 1.18 | 1,826 |
| January 2013 | (0.94) | 1,906 |
| February 2013 | 5.00 | 1,475 |
| March 2013 | (5.00) | 1,202 |
| April 2013 | (5.00) | 994 |
| May 2013 | (5.00) | 1,024 |
| Total | **2.87** | 23,659 |

Furthermore, the significant monthly variations in the PEA that are necessitated by the supply/load mismatches under the block-and-spot approach cause unpredictable distortions to the bundled service rates against which ARES must compete, and they do not allow for transparent benchmarks for customers to compare with ARES product offerings and to confidently make economic retail service decisions. This is partially due to the unpredictability in overall unit supply costs that is inherent in the block-and-spot approach, and partially due to the fact that the PEA must be calculated based on historical rather than instantaneous gaps between the supply costs and rates, taking into account the ever-changing deferred cost recovery balance. The chart below depicts these distortions over time for ComEd, for the period in which all of the necessary data was available.[17] For each month, it portrays two values. The first value is the difference between the total bundled service supply costs accrued during the month on a dollars-per-megawatt-hour basis and the total bundled service supply revenues accrued that month on a dollars-per-megawatt-hour basis. In other words, this value represents the shortfall between the supply revenues and the supply costs in a given month. The second value is the PEA assessed during that month. Appendix C contains the calculations and values that support the chart.

[15] Data from http://www.icc.illinois.gov/ormd/PEA.aspx. Some data is from reports that were not yet posted on this website, but which were made publicly available.

[16] Furthermore, the PEA has returned to its maximum capped positive value. While it was -$5.00/MWH in June 2013, it was $3.21/MWH in July, $5.00/MWH in August, and $5.00/MWH in September.

[17] Data from http://www.icc.illinois.gov/ormd/PEA.aspx. Some data is from reports that were not yet posted on this website, but which were made publicly available.

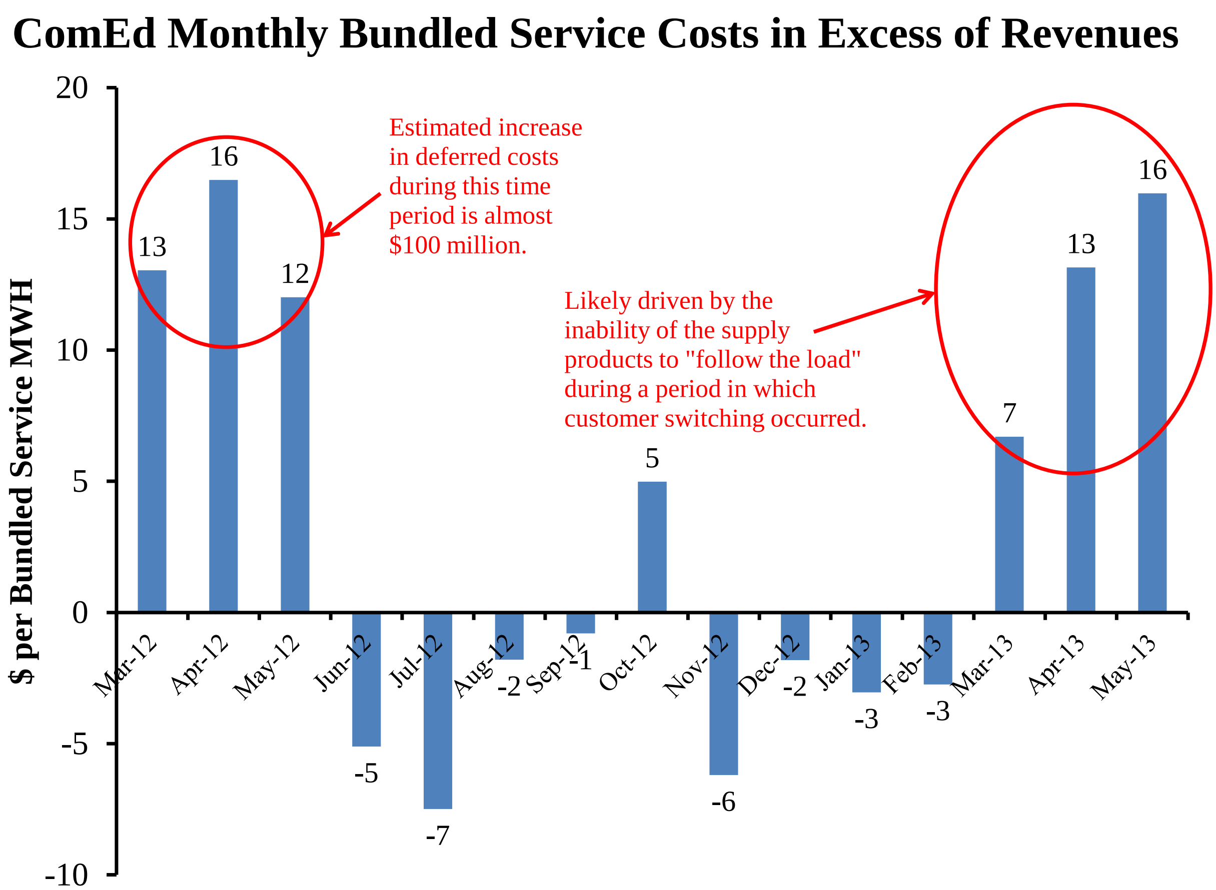



If the PEA were providing a reasonable signal of the underlying supply cost in a given month, then we would expect it to be at its maximum value of $5/MWH when a revenue shortfall exists (in other words, it would be at its maximum to mitigate that shortfall as much as possible) and we would expect it to be at its minimum value of -$5/MWH when a revenue excess exists (in other words, it would be at its minimum to mitigate the excess as much as possible). However, this dynamic is not observed. In fact, in 67% of the months, the PEA actually further contributed to a shortfall or excess, rather than mitigating it. This is no fault of ComEd. Instead, it is simply a result of the real-world constraints in reconciling revenues and costs when there are routinely significant mismatches between these values, and when there are costs from previous months that must be recovered on a deferred basis, all of which is the case under the block-and-spot approach. Unfortunately, this dynamic by itself causes unpredictable and non-transparent rate swings of up to $10/MWH, which make it more difficult for customers to assess actual bundled service costs going forward, and to confidently make economic retail service decisions.

Evidence of the costs and unnecessary adverse financial risks for customers under the block-and-spot approach also can be found in the regulatory asset corresponding to unanticipated supply costs that have been incurred but that have not yet been recovered from customers. With block-and-spot purchases, bundled service rates must be set based on the anticipated cost of bundled service supply, which inevitably will differ from the actual cost. Due to the mismatch, deferred cost recovery balances can become especially large under the block-and-spot approach, which can have detrimental effects on both customers and retail competition in general. For example, the looming deferred cost recovery balances make it more difficult for customers to rely on current bundled service rates as an indication of the bundled service rates that they will pay in the future, and therefore, similar to the PEA, they make it difficult for customers to confidently make economic retail service decisions. Furthermore, the recovery of these balances must occur in future periods and may cause future default service rates to diverge from contemporaneous market prices. Since the recovery occurs in future periods, customers sometimes can bypass payment for power procured on their behalf by switching off of bundled service between the time that the cost is incurred and the time that it is recovered. Similarly, customers who switch to bundled service effectively may be required to pay for power from prior periods that they did not consume. This creates issues of cross-subsidization between customers. In addition, deferred cost recovery balances must be financed by the utility, and this in turn could adversely affect the utility's available credit capacity and/or its cost of financing. These costs of doing business are ultimately passed on to customers. Finally, substantial deferred cost recovery balances may lead to higher administrative costs due to the additional burden of managing deferrals and reconciliations. These administrative costs ultimately must be passed on to customers.

As depicted in the chart below, there were two periods in the recent past in which costs were significantly higher than revenues, even after the PEA was applied, implying that the deferred cost recovery balance can increase by a large amount over a short period of time under the block-and-spot approach.[18] Specifically, during the March – May 2012 period, the monthly cost-revenue gap varied between $12/MWH and $16/MWH. This equates to an increase in the deferred cost recovery balance of almost $100 million in only three months, to be recovered by future bundled service customers.

[18] Data from http://www.icc.illinois.gov/ormd/PEA.aspx. Some data is from reports that were not yet posted on this website, but which were made publicly available.




The second period in the recent past in which the monthly cost-revenue gap was noticeably high was the March – May 2013 period. During this period, the monthly cost-revenue gap varied between $7/MWH and $16/MWH, to be recovered by future bundled service customers. This corresponded to a period of customer switching off of bundled service due in large part to the City of Chicago's municipal aggregation program.

Given the uncertainty about future market prices and future bundled service load levels, especially with over half of the current Illinois municipal aggregation contracts expiring during the 2014-2015 procurement year,[19] the supply/demand mismatches and their associated effects on costs could be especially large under the block-and-spot approach, resulting in potentially very high costs to be recovered from future bundled service customers.

### D. The FPFR Product Approach Protects Customers from Significant Adverse Financial Risks and Rate Instability

The FPFR product approach protects customers from the significant adverse financial risks and rate instability associated with the block-and-spot approach. For the duration of a FPFR product, there is no mismatch between the fixed-price supply procured and the uncertain load requirements, as there is under the block-and-spot approach. As a result, the suppliers of FPFR

[19] 2014 Draft IPA Plan, at 37-38.

products assume, manage, and cover the complicated supply costs and risks associated with the load requirements, while guaranteeing a fixed price for customers, rather than exposing customers to the risks inherent in the block-and-spot approach. FPFR products provide customers insurance against unanticipated costs and risks during the term of the full requirements contract, while the block-and-spot approach leaves customers exposed to unanticipated costs and risks. As such, the FPFR product approach clearly can provide significant price stability benefits for customers. Furthermore, if bundled service customers were supplied entirely by FPFR products instead of through a block-and-spot approach, there essentially would be no uncertainty about the all-in cost to supply a megawatt-hour of load during the upcoming rate period (assuming that all of the supply is procured for that period by the time that the default service rate is set). As a result, rates would be set with a matching of bundled service revenues to supply costs, and this should severely reduce PEA assessments and deferred cost regulatory asset balances.[20]

The FPFR product approach accommodates customer switching better than the block-and-spot approach does, because issues pertaining to rate distortion, rate instability, and deferred cost recovery are not triggered by customer switching with the FPFP product approach, like they are with the block-and-spot approach. With the FPFR product approach, customers can achieve cost savings when market prices drop by switching to ARES service, without increasing the proportion of above-market supply that the remaining bundled service customers must bear, and thereby without adversely affecting the all-in price per megawatt-hour of the supply, unlike would be the case with the block-and-spot approach. Similarly, if market prices rise, then customers can migrate back to bundled service without driving up bundled service rates by requiring the utility to purchase more energy in the high-priced spot market as it would need to do under the block-and-spot approach. Effectively, the FPFR product price acts as a cap on rates, because FPFR products provide guarantees to customers that they will pay no more than the agreed-upon price for the bundled service supply, while still allowing customers to switch to ARES and pay lower prices if they can find a lower price.[21]

### E. FPFR Product Suppliers Require Compensation for Covering Costs and Risks for Customers, but Unlike in the Block-and-Spot Approach, in the FPFR Product Approach the Coverage of These Costs and Risks Is Subjected to Competitive Market Forces, and Is Provided on the Basis of Lowest Price

In any market, participants require compensation for the costs and risks which they bear by providing a product. In the case of FPFR product suppliers, this compensation is embedded in the suppliers' bid prices, and it is simply a monetization of costs and risks that the suppliers of these products bear to the benefit of customers by providing fixed-price guarantees for load following service. Such costs and risks may include the following:

[20] FPFR products can be introduced in an existing block-and-spot portfolio like the Illinois bundled service supply portfolios. This would reduce the magnitudes of the PEA and the deferred cost regulatory asset balances.

[21] This is not true under the block-and-spot approach because under this approach customers (through the utility) commit to fixed quantities of supply at fixed prices, and must incur the associated above-market costs on the entire contracted quantities even if market prices drop and customers switch to ARES.

- Customer migration – the financial costs and risks associated with the uncertainty regarding customer switching (including customer switching due to municipal aggregation programs) and its effect on the default service volumes to be supplied.[22]

- Usage and price uncertainty – various costs and risks due to unexpected events that affect usage and price levels.[23]

- Unexpected congestion – various costs and risks associated with the possibility that differences in prices between a given trading hub and the delivery location will be higher than expected values.

- Adverse selection – the costs and risks associated with the likelihood that high cost-to-serve customers (e.g., with less attractive load shapes) will disproportionately remain on default service due to ARES' lack of interest in marketing to such customers.

- Adverse developments in energy markets during the time a bid is held open – even for a few days, while the bids are evaluated and considered for approval by the applicable regulatory body.

- Potential changes in laws and regulations.

- Administrative and legal costs.

- Credit-related costs (e.g., costs associated with posting collateral).

These costs and risks are also present under the block-and-spot approach, but that approach shifts many of these costs and risks from the FPFR product suppliers to the retail customers.

As will be explained later, robust quantitative analysis based on actual market data from other regions indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is reasonable. Specifically, the analysis indicates that, in comparison to the FPFR product approach, the increases in risk borne by residential customers under the block-and-spot approach are not balanced by a proportionate decrease in the expected default service rate level. While uncertainty about customer switching may be higher in Illinois than it is in some other regions, this is no reason to believe that the basic conclusions about the tradeoff between these two procurement approaches would change. If uncertainty about customer switching is higher in Illinois, then the compensation required by

[22] Customers have an incentive to elect service from ARES when the default service rate is higher than ARES prices, and they have an incentive to elect default service when the rate is lower than those prices. This customer switching option can be very valuable for customers, but can be costly to the seller of the FPFR default service supply product given the need to provide additional supply when market prices are high and/or manage excess supply when market prices are low.

[23] These include extreme weather patterns, changes in customer usage patterns, plant outages or transmission line outages (which also affect the congestion cost), fuel price shocks, and unexpected economic growth levels. Furthermore, the general positive correlation between loads and prices (e.g., a heat wave drives up both prices and loads) compounds the potential costs associated with this uncertainty.

Illinois FPFR product suppliers to bear resultant higher costs and risks to the benefit of customers will be higher, but the costs and risks that would be borne by Illinois customers under the block-and-spot approach also will be higher, so this does not justify rejection of the FPFR product approach in Illinois. In fact, bearing and managing risks is a core business function of FPFR product suppliers, and their well-established departments of experienced portfolio and risk management personnel can tap into various facets of the power markets in response to changes in conditions much more flexibly than can be done through a litigated regulatory procurement proceeding held once per year. As a result, even in an environment in which there are greater costs and risks associated with customer migration, there is no reason to assume that the compensation required by FPFR product bidders to bear and manage these costs and risks to the benefit of customers would be excessively high relative to the magnitudes of the costs and risks that customers otherwise would directly bear under the block-and-spot approach.

In fact, the FPFR product approach harnesses the full benefits of wholesale competition. Specifically, unlike the situation under the block-and-spot approach, FPFR product bidders compete on the basis of the lowest price to satisfy all aspects of the default service customers' load requirements, including the portfolio management function.[24] It is reasonable to assume that parties that desire to be winning bidders in the FPFR solicitations will consider the costs and risks associated with all forms of supply available to them to satisfy their obligation to satisfy all of the bundled service customers' supply needs at a fixed price and, in order not to be undercut by another bidder, will reflect in their bid prices the benefits of any opportunity that they believe is the least-cost supply opportunity. Thus all customers – including those who remain with the utility, not just those who switch to competitive retail suppliers – will get the benefits of two levels of competition: the competition among generating resources in the underlying wholesale market, and the competition among FPFR bidders regarding how best to buy in that wholesale market and manage risks to satisfy the FPFR obligation for customers. In contrast, under the block-and-spot approach like that currently adopted in Illinois, portfolio management decisions are made through an annual regulatory process, so there is no competition among qualified parties to determine the most cost effective ways to develop and manage supply portfolios that allow for the least-cost provision of fixed-price bundled service for customers.

### F. The Benefits of the FPFR Product Approach Are Widely Recognized in Other Restructured Jurisdictions

Indeed, the FPFR product approach provides numerous benefits relative to the block-and-spot approach with regard to risks associated with rate distortion and rate instability, deferred cost accumulation and recovery, and the ability to harness the full benefits of wholesale competition. Over time, as the pricing of FPFR products has evolved and the adverse risks to customers of not using FPFR products have been better understood, the benefits of the FPFR product approach have become widely recognized by regulators. In fact, the FPFR product approach has become by far the most prevalent and favored form of default service supply procurement

[24] FPFR product suppliers have the responsibility for continuously satisfying the uncertain and constantly changing supply requirements at the agreed-upon price, and therefore must manage the associated costs and risks through their supply portfolio decisions.

for smaller customers in restructured jurisdictions, and there are many sellers willing to compete on the basis of lowest price to provide FPFR products. Examples of specific jurisdictions in which full requirements supply products are procured include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island, and Washington D.C. In fact, numerous state public utility commissions have explicitly recognized the comparative benefits of the FPFR product approach. For example, in a 2010 default service proceeding, the Rhode Island Public Utilities Commission stated as follows:

> *If the residual compensation risks are deemed to be on the low side, then there are other countervailing policy considerations that arguably support a FRS [FPFR product] approach. First, Rhode Island remains a retail choice state according to the terms of the Utility Restructuring Act and subsequent amendments. While there currently may be minimal activity in terms of the number of customers served by non-regulated suppliers, it does not necessarily follow that mass migration from Standard Offer service will not occur in the near future. A number of other jurisdictions have experienced an up-tick in the level of supplier activity in residential and small commercial classes. <u>A FRS [FPFR product] approach utilizing layered procurements presents minimal migration risk. On the other hand, a managed portfolio approach relying on block purchases could lead to mass migration and substantial costs borne by National Grid from unsubscribed "take or pay" electricity, which costs would ultimately be recovered from a smaller class of standard offer ratepayers.</u> This outcome poses a real concern about equity and rate impacts. Like the stranded costs that ratepayers were required to pay at the onset of retail competition, a mass migration from standard offer service would also result in significant incremental costs being passed on to ratepayers. <u>Clearly from this perspective, FRS [FPFR] contracts are more consistent with the Commission's responsibility to ratepayers, particularly given the limited savings that would accrue to customers in a managed portfolio regime.</u>[25] (emphasis added)*

Notably, that commission's final order in that proceeding rejected arguments to adopt a block-and-spot approach, and approved an approach based overwhelmingly on FPFR products for residential customers.

The Maine Public Utilities Commission also has explained the advantages of the FPFR product approach which make this approach its preference for utility supply:

> *The Commission's approach of supplying standard offer by soliciting "all requirements" service through competitive bid allows the market to produce the lowest prices and places the risk of "portfolio management" on the bidders. Market participants have the specialized expertise and necessary resources to manage resource portfolios in the current electricity environment and their*

[25] Report and Order – In Re: National Grid's Proposed 2011 Standard Offer Supply Procurement Plan and 2011 Renewable Energy Supply Procurement Plan, Docket No. 4149, State of Rhode Island and Providence Plantations Public Utilities Commission, September 23, 2010, at 19-20.

*shareholders (rather than ratepayers) have the planning risk to [the] extent that their portfolio costs are higher than market costs.*[26]

As another example, after experimenting with having some portion of the Pennsylvania utilities' residential default service supply portfolios be procured through the block-and-spot approach, the Pennsylvania Public Utility Commission repeatedly affirmed its general preference for the FPFR product approach over the block-and-spot approach, noting the relative benefits of the FPFR product approach:

*We believe that PECO's FPFR procurement approach is preferable to the procurement approach utilized by PECO in its DSP I and the OCA's proposal here, because it better shields customers from price variations by placing all risk onto the seller of the FPFR product.*[27,28]

*The [FPFR product approach] insulates default supply customers from the volatility associated with wholesale market conditions with the supplier bearing the risks of factors such as customer migration, weather, load variation and economic activity.*[29]

*[W]e will not require nor do we specifically endorse the use of the [managed portfolio] approach at this time. We do express a preference for continued reliance by DSPs on the [FPFR product] approach to the extent this method best suits the DSP's particular procurement needs.*[30]

In sum, the FPFR product approach has become by far the most prevalent and favored form of default service procurement for smaller customers in restructured jurisdictions, and the benefits of this approach are widely recognized by regulators.

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[26] Order, Docket No. 2006-557, Maine Public Utilities Commission, January 2, 2007, at 8.

[27] Petition of PECO Energy Company for Approval of its Default Service Program II, Pennsylvania Public Utility Commission Docket No. P-2012-2283641 (Order entered October 12, 2012), at 17.

[28] Both "the procurement approach utilized by PECO in its DSP I" and "the OCA's proposal here" were distinguished by their use or renewal of the block-and-spot approach.

[29] Default Service and Retail Electric Markets, Pennsylvania Public Utility Commission Docket No. L-2009-2095604 (Order entered October 4, 2011), at 54.

[30] Default Service and Retail Electric Markets, Pennsylvania Public Utility Commission Docket No. L-2009-2095604 (Order entered October 4, 2011), at 56.

## III. The IPA's Analysis of the Two Approaches Contains Significant Shortcomings That Invalidate Its Conclusions, while Analyses without Such Shortcomings Confirm the Relative Merits of the FPFR Product Approach

### A. The IPA's Analysis Contains Significant Shortcomings That Invalidate Its Conclusions about the Relative Merits of the FPFR Product Approach

Section 6.7 of the 2014 Draft IPA Plan presents an analysis designed to compare the FPFR product approach with the block-and-spot approach. Based on this analysis, the IPA states, "The analysis in Chapter 6 indicates that full requirements products do not have a great cost or risk advantage over a block-based strategy, when the current hedge portfolios are taken into account...The IPA is not prepared to recommend the use of full requirements products."[31]

The analysis performed by the IPA may be useful to provide some insight regarding which permutations of the block-and-spot approach expose customers to more risk than others, and therefore it may be useful to help assess which permutations of the block-and-spot approach are more or less attractive than others. But, based on the description of the analysis found in Section 6.7 and Appendix F of the 2014 Draft IPA Plan, it is clear that the analysis contains significant shortcomings that make it unable to provide useful information regarding the relative merits of the FPFR product approach as compared to the block-and-spot approach. As a result, conclusions drawn from the IPA's analysis regarding the attractiveness, or lack thereof, of including FPFR products in the IPA Plan should be disregarded. The remainder of this section describes significant shortcomings of the IPA's analysis that invalidate its findings regarding the FPFR product approach relative to the block-and-spot approach.[32]

### B. The IPA's Analysis Is Based on an Unsupported and Untested Assumption about FPFR Product Pricing

The IPA's analysis is based on an unsupported and untested assumption about FPFR product pricing. The assumption specifically pertains to the assumed compensation that FPFR product suppliers will include in their prices to cover the adverse risks that the suppliers will bear, to customers' benefit, due to the uncertainties and correlations pertaining to the costs of supply components and the loads that must be served. Instead of relying on any actual FPFR product price data, the IPA arbitrarily assumes that the compensation that FPFR product suppliers will include will be enough to cover their expected unit costs across a spectrum of simulated scenarios, plus an additional amount that is up to 0.3 times the difference between the expected unit cost and the unit cost that the suppliers would incur in one of the more extreme scenarios modeled.[33] Furthermore, in managing its costs and risks, the IPA assumes that any FPFR product supplier will be constrained to one of eight block-and-spot strategies that the IPA chose to test, instead of recognizing that FPFR product suppliers have a wide universe of wholesale products (including, but not constrained to, block products and spot purchases) and specific risk management strategies available to them to satisfy their obligations, and that they have

[31] 2014 Draft IPA Plan, at 89.

[32] Additional significant shortcomings may exist that are not identified or described.

[33] 2014 Draft IPA Plan, at 72-73.

developed strategies that they often implement to reduce their risks.[34] In fact, the IPA recognizes that its analysis may not reflect actual FPFR product pricing.[35] Given these facts and the arbitrary nature of the IPA's assumption regarding FPFR product pricing, the IPA's analysis cannot be relied upon to provide reasonable estimates of the pricing of FPFR products in Illinois.

### C. The IPA's Analysis Omits or Underestimates Drivers of Costs and Risks That Are Directly Borne by Customers under the Block-And-Spot Approach

Another substantial shortcoming that invalidates the IPA's analytical comparison of the FPFR product approach with the block-and-spot approach is the fact that the IPA's analysis omits or underestimates various drivers of costs and risks that are directly borne by customers under the block-and-spot approach, but from which the FPFR product approach provides protection for customers. As a result, in its analysis and comparison of the two approaches, the IPA underestimates the risks to customers under the block-and-spot approach.

#### *i. The IPA's Analysis Underestimates Load Uncertainty*

For example, bundled service load uncertainty has a major influence on the costs and risks that customers directly bear under the block-and-spot approach,[36] and there is a great deal of uncertainty about the bundled service load levels in the future, even the near future. Part of this uncertainty stems from the fact that over half of the current Illinois municipal aggregation contracts will expire during the 2014-2015 procurement year.[37] In addition, customers may switch at any time regardless of when various municipal aggregation contracts expire. In fact, recent history provides an insightful look at how loads can change in a short period of time: less than 12% of ComEd's total residential customers had been served by ARES as of May 2012, yet almost 68% were receiving ARES service just one year later.[38] Furthermore, additional load uncertainty is driven by factors such as unexpected weather patterns, changes in customer usage, and unexpected economic growth levels.

Yet, the IPA's analysis underrepresents all of this uncertainty. In far more than half of the scenarios modeled by the IPA in its analyses, the IPA assumes that the actual monthly on-peak and off-peak average bundled service load levels exactly match forecasted values. Specifically, the IPA assumes that actual average bundled service loads match forecasted values in 74% of the scenarios modeled for Ameren, and the assumption is only slightly lower, at 63%, for

[34] 2014 Draft IPA Plan, at 73.

[35] 2014 Draft IPA Plan, at 89.

[36] As has been explained previously, this is due to the mismatch between the fixed quantities of fixed-price supply purchased and the uncertain bundled service load requirements. This is also acknowledged by the IPA, as it states in the context of the block-and-spot approach, "…it is clear that load variability increases cost risk in the sense of absolute cost and of uncertainty." (2014 Draft IPA Plan, at 65.)

[37] 2014 Draft IPA Plan, at 37-38.

[38] 2013 Annual Report, Office of Retail Market Development of the Illinois Commerce Commission, June 2013, at 15.

ComEd.[39] Furthermore, in the remaining minority of scenarios, the IPA caps the degree to which actual loads may deviate from the forecasted values. For example, according to the IPA's characterization of the lowest load scenarios and the highest load scenarios that it included in its analysis for ComEd, the lowest bundled service load level outcome is only approximately 15% lower than the forecasted bundled service load level, and the highest load level outcome is only approximately 47% higher than the forecasted bundled service load level.[40,41] Based on the real-world evidence presented about load uncertainty, these are likely to be very unrealistic bounds on the amount of future bundled service load, especially since current bundled service load levels are a relatively small fraction of the entire customer base but there is a real risk that load that has switched to ARES could switch back to bundled service. In fact, recent experience demonstrates that the IPA's assessments of the "extremes" of potential outcomes pertaining to factors that contribute to supply cost risks have been excessively narrow. Specifically, in the IPA's defense of a block-and-spot approach in its 2013 Procurement Plan, the IPA presented what it characterized as the likely high and low "extremes" of the average monthly on-peak prices starting in June 2013 for the Northern Illinois Hub and separately for the Illinois Hub; in four of the six cases revealed so far (June, July, and August, for each of Northern Illinois Hub and Illinois Hub), the actual price outcomes have fallen outside of the IPA's predicted extremes.[42] Considering all of these facts, the IPA has very likely underestimated the uncertainty about future load levels, and therefore it has underestimated the related costs and risks that customers directly bear under the block-and-spot approach.

Since bundled service load uncertainty has a major influence on the costs and risks that customers directly bear under the block-and-spot approach, it is important to recognize another assumption in the IPA's analysis about load uncertainty that invalidates its results. Specifically, in the scenarios in the IPA's analysis in which actual monthly on-peak or off-peak loads do not match initial load forecasts, the IPA assumes that the forecast evolves over time in a single direction, and in a perfectly linearly fashion, toward the actual load outcome, rather than capturing the reality that the forecast of load for a given delivery period may be higher at one point in time leading up to the delivery period, lower at another point in time leading up to the

[39] 2014 Draft IPA Plan, at Appendix F F-6.

[40] 2014 Draft IPA Plan, at 41 and Appendix F F-6.

[41] The IPA has assumed that, in all of its scenarios, the bundled service load level will not be less than the "low" load case provided by the given utility and that it will not be greater than the "high" load case provided by the given utility. While the low and high cases provided by the utilities allow for sensitivity analyses, the utilities do not indicate that these cases represent boundaries on the potential future load outcomes.

[42] See "2013 Illinois Power Agency Electricity Procurement Plan Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts Final Plan Conforming with the Commission's December 19, 2012, Order" in Docket 12-0544, at 46-49. Page 46 states, "This conclusion means that portfolio strategy decisions can be made in an environment of a relatively well-defined bandwidth of market price projections…the range of possible outcomes represented by the scenarios below are [sic] likely to represent the extremes of ranges of actual outcomes." Page 48 shows that none of the corresponding IPA-predicted low "extremes" for the Northern Illinois Hub monthly average on-peak price for June, July, or August 2013 was less than about $41/MWH, yet the actual average on-peak hourly real-time energy market price for the Northern Illinois Hub was $36.79/MWH for June and $36.93/MWH for August. Page 49 shows that the corresponding IPA-predicted low "extreme" for the Illinois Hub monthly average on-peak price was about $38/MWH for June and about $40/MWH for July; however, the actual average on-peak hourly real-time energy market price for the Illinois Hub was $33.59/MWH for June and $37.99/MWH for July. Real-time market price data was provided by Ventyx / Energy Velocity.

delivery period, etc.[43] As such, the IPA's analysis cannot represent the spectrum of possible scenarios in which too much or too little block product quantity is procured under the block-and-spot approach. Therefore, this is another contributor to the IPA's underestimation of the financial risks to customers under the block-and-spot approach.

#### *ii. The IPA's Analysis Is Based on an Unsupported Key Assumption about the Relationship between Price Movements and Bundled Service Load Levels*

In addition, the IPA has made an unsupported key assumption about the relationship between market price movements and bundled service load levels, which as explained above is an important driver of the costs and risks that customers directly bear under the block-and-spot approach. In the IPA's Monte Carlo simulation analysis, the correlation between average market prices and average bundled service loads is represented by applying some correlation between two variables: a trend factor that is applied to the initially expected price level to determine how market prices move, and the bundled service load level outcome.[44] The IPA implements this correlation by applying a correlation coefficient between the assumed price trend factor and the assumed load level outcome.[45] In simulation models, correlation coefficients are sometimes used to incorporate a relationship between two variables, such as the price trend factor and the load level outcome in the IPA's analysis. Mathematically, the value of a correlation coefficient must be between -1.0 and 1.0. A correlation coefficient of 1.0 means that both variables' values always move in the same direction; had the IPA applied a correlation coefficient of 1.0, it would have signaled a strong positive relationship between market prices and load levels.[46] A correlation coefficient of zero means that there is no relationship between the two values; had the IPA applied a correlation coefficient of zero, it would have signaled that there is no systematic tendency for customers to elect bundled service when market prices increase, or to switch off of bundled service when market prices decrease, or for increased power demand to drive up market prices. Clearly, assuming a correlation coefficient of zero would be nonsensical in this case. Correlation coefficient values that are closer to zero than to 1.0 indicate a weaker relationship between the two variables' values, while correlation coefficient values that are closer to 1.0 than to zero indicate a stronger positive relationship between the two variables' values. The IPA chose to use a correlation coefficient of 0.2, which of course is much closer to zero than 1.0.[47] This assumed value is entirely unsupported, and it indicates a slightly positive but fairly weak relationship between prices and loads, especially given the additional uncertainty factor that the IPA applies to calculate its assumed market prices which weakens the relationship in the IPA's analysis regardless of the correlation coefficient assumed. Given the basic economic linkages between demand and market prices, as well as the economic incentives for customers to elect bundled service when market prices increase and to switch off of bundled service when market prices decrease, the IPA's

[43] 2014 Draft IPA Plan, at Appendix F F-4.

[44] 2014 Draft IPA Plan, at Appendix F F-6.

[45] 2014 Draft IPA Plan, at Appendix F F-6.

[46] However, the IPA also applied an additional uncertainty factor to calculate its scenarios' market prices, and this weakens the relationship in the IPA's analysis regardless of the correlation coefficient assumed.

[47] 2014 Draft IPA Plan, at Appendix F F-6.

unsupported assumption of a relatively weak correlation between average market price levels and bundled service load levels easily may misrepresent the true relationship, especially in light of statements made by the IPA implying a recognition of a strong relationship between market prices and bundled service loads.[48,49,50,51,52]

### *iii. The IPA's Analysis Is Not Fundamentally Structured Correctly to Capture the Relationship between Market Prices and Bundled Service Loads*

Furthermore, simply increasing the correlation coefficient would not fix this problem with the IPA's analysis. In reality, price-sensitive customers do not switch to or from bundled service because market price levels are high or low, but instead they switch because market price levels are high or low as compared to the bundled service rate. This difference between market price levels and the bundled service rate is sometimes referred to as "headroom," and it can be positive or negative. This distinction is doubly important, because it is often the differences between the bundled service rate and the market prices, and not just the absolute values of the market prices themselves, which drive the costs and risks directly borne by customers when a block-and-spot approach is implemented and customers switch. Therefore, the basic structure of the IPA's model would need to be changed as a first step toward fixing this particular problem. Unfortunately, however, even if the structure of the model were changed, the IPA has acknowledged that it is not confident about the numerical assumptions that it would apply to represent the relationship, as it states, "The necessary timeframe or magnitude of rising prices (or, more accurately, the spread between the bundled utility rate and the best price a municipal aggregation supplier will offer) for customers to engage in this behavior is unknown, and the IPA is interested in feedback from stakeholders as to expected quantitative or qualitative parameters."[53] In sum, another one of the reasons why reliable conclusions cannot be drawn from the IPA's analysis about the relative merits of the block-and-spot approach and the FPFR product approach is that the IPA's analysis is not fundamentally structured correctly to capture

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[48] "Customer migration behavior is particularly important because of its linkage with market prices." (2014 Draft IPA Plan, at 38).

[49] "The reverse is true in a period of falling power prices, as has been experienced over the last several years: the blended price of IPA supply would be higher than the contemporary price of power, or the price of new contracts. That would motivate rational consumers to depart from utility service for the price of a new contract either with an ARES or through municipal aggregation. If the market is moving into an environment of rising power prices it is equally true that consumers would be motivated to return to utility service." (2014 Draft IPA Plan, at 38).

[50] "Although it is not yet clear how governments running municipal aggregation programs and individual customers who may opt out or leave a program will act, it is likely that customers would return to utility service in periods of rising prices. The Agency and the utilities would have to arrange for additional supply to cover the returning load, at a price higher than was paid for the originally forecasted load and higher than would be built into utility tariffs. Therefore, load whose return is correlated with high prices (and whose departure is correlated with low prices) represents not only load uncertainty but also an absolute price risk." (2014 Draft IPA Plan, at 39).

[51] "This demonstrates that customers will return to utility service when they perceive a price advantage in doing so." (2014 Draft IPA Plan, at 71).

[52] "Figure 6-10 shows that customers will respond to their perceptions of the difference between utility bundled service and alternative suppliers (whether the utility supply comes from full-requirements contracts or a portfolio of block contracts)." (2014 Draft IPA Plan, at 72).

[53] 2014 Draft IPA Plan, at 39 Footnote 64.

the relationship between market prices and bundled service loads and the IPA is not confident about the relationship even if the analysis were properly structured, yet this relationship is a key driver of the costs and risks that customers directly bear under the block-and-spot approach.

#### iv. *The IPA's Analysis Ignores the Cost and Risk Resulting from Uncertainty with Respect to Hourly Load and Spot Price Patterns during the Intra-Month On-Peak and Off-Peak Periods*

The IPA's analysis also has omitted another aspect of load and price uncertainty and correlations, which is important because load and price uncertainty and their correlations are major sources of the costs and risks that customers directly bear under the block-and-spot approach, as explained previously. Specifically, while the scenarios in the IPA's analysis reflect some risk that the average hourly spot price during a given month's on-peak or off-peak period might turn out to be different than the previously expected level, and that the average bundled service load during a given month's on-peak or off-peak period might turn out to be different than the previously expected level, it ignores the cost and risk resulting from uncertainty with respect to the intra-period[54] hourly load and spot price patterns.[55] Instead, the IPA apparently assumes that the effect on cost of intra-period price and load shaping (i.e., the effect on cost that results from the fact that, within a monthly on-peak or off-peak period, the hourly spot prices at which supply is purchased under a block-and-spot approach are generally higher when hourly loads are higher) is a constant percentage of the average hourly price during the period. An example will help to illustrate this point. For instance, consider an example that the IPA presented:

> *According to Table 6-1, the load shape and its correlation with prices adds about 6% to the average cost of supplying energy to retail customers. In other words, if the total load is 500 MWh, and the average hourly power price is $20/MWh, the product of load and average price is $10,000 but the actual cost of energy to serve load will be $10,600. A 500 MWh hedge will cost $10,000. If the average price rises to $30/MWh, the value of the hedge will rise to $15,000, a $5,000 increase. But the actual cost to serve load will rise to $15,900 – an increase of $5,900 of which $900 is unhedged. To actually hedge costs, one would have to buy 530 MWh of hedges – 106% of load. Note that this would not really be a perfect hedge, as not all hourly prices move in proportion to the average.*[56]

The key sentence in this example is the last one: "…not all hourly prices move in proportion to the average." This is true, and it is also true that not all hourly loads move in proportion to the average when there are changes in the expectations about loads, either. In fact, even if average hourly prices and loads over a given monthly on-peak or off-peak period ended up matching expectations, there still would be uncertainty about the cost to supply the load under the block-and-spot approach (against which customers would be protected under the FPFR product approach), because there remains uncertainty about the patterns of hourly loads and hourly

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[54] In other words, within the given month's on-peak or off-peak period.

[55] 2014 Draft IPA Plan, at Appendix F F-5.

[56] 2014 Draft IPA Plan, at 67.

prices within the period; for example, a period that is characterized by a couple of weeks of mild weather followed by a couple of weeks of extreme weather could have a much higher additional cost due to the hourly price and load patterns than one that has relatively homogenous weather throughout the period. The IPA's analysis ignores this source of risk, which customers bear under the block-and-spot approach because block products provide no hedge against this risk. Furthermore, this uncertainty may add expected costs to the block-and-spot approach which the IPA's analysis ignores, because there may be a tendency for more extreme hourly price and load patterns (which result in higher $/MWH costs resulting from the hourly intra-period load and price shapes) to correspond to higher-than-expected overall load levels during the period.

#### v. *The IPA's Analysis Appears to Omit the Risk that the Costs of Any of the Non-Energy Supply Components Vary from Expectations*

Another risk to customers under the block-and-spot approach that the IPA's analysis appears to omit is the risk that the costs of any of the non-energy supply components vary from expectations. Ancillary services costs, marginal loss credits, auction revenue rights credits, and final capacity costs are uncertain. Under the FPFR product approach, the product suppliers protect customers from these uncertainties during the duration of the product. But, under the block-and-spot approach, customers are directly exposed to these uncertainties. By not accounting for these uncertainties, the IPA's analysis underestimates the risks to customers under the block-and-spot approach.

### D. The IPA's Melding of Various Simulations May Have Resulted in Inaccuracies, Distorted Results, or Misrepresentations of the Most Reasonable and Appropriate Ways to Integrate the FPFR Product Approach into the Existing Supply Mix

It should also be noted that the IPA's analysis of the FPFR product approach involves a melding of various simulations, in which distributions of various outcomes under different simulations are somehow combined, as opposed to a performing a straightforward simulation of the FPFR product approach.[57] It is unclear whether inaccuracies, distorted results, or misrepresentations of the most reasonable and appropriate ways to integrate the FPFR product approach into the existing supply mix, are introduced by this piecemeal approach or by any other aspects of the IPA's analysis. It is very possible that such problems exist in the IPA's results, as the results appear counterintuitive at times. For example, in one of the simulation runs for Ameren, the model indicates that the integration of the FPFR product approach would significantly increase the cost uncertainty borne by customers, despite the fact that FPFR products are insurance products by nature, providing fixed-price guarantees for all of the supply aspects of load following service, and despite the fact that that another simulation run for Ameren indicates that the FPFR product approach would significantly decrease the cost uncertainty borne by customers.[58]

[57] 2014 Draft IPA Plan, at 73-77.

[58] 2014 Draft IPA Plan, at 75.

### E. The IPA's Analysis Does Not Address All of the Aspects of Costs and Risks That Are of Concern with Respect to a Given Bundled Service Supply Approach

The IPA's analysis of the FPFR product approach relative to the block-and-spot approach also suffers from the shortcoming that it does not address all of the aspects of costs and risks that are of concern with respect to a given bundled service supply approach. The IPA's analysis only looks at the distribution of hypothetical supply costs over some defined later period. While this provides some sense of the uncertainty about supply costs accrued during that window of time, it does not allow for an assessment of important factors under any given supply approach such as the potential for significant period-to-period rate changes and distortions to which customers would be exposed, the amount of costs that are stranded in a regulatory asset account and which the approach would rely on future bundled service customers to cover, and the predictability and transparency of the resultant supply rates which allow customers to confidently make economic retail service decisions.

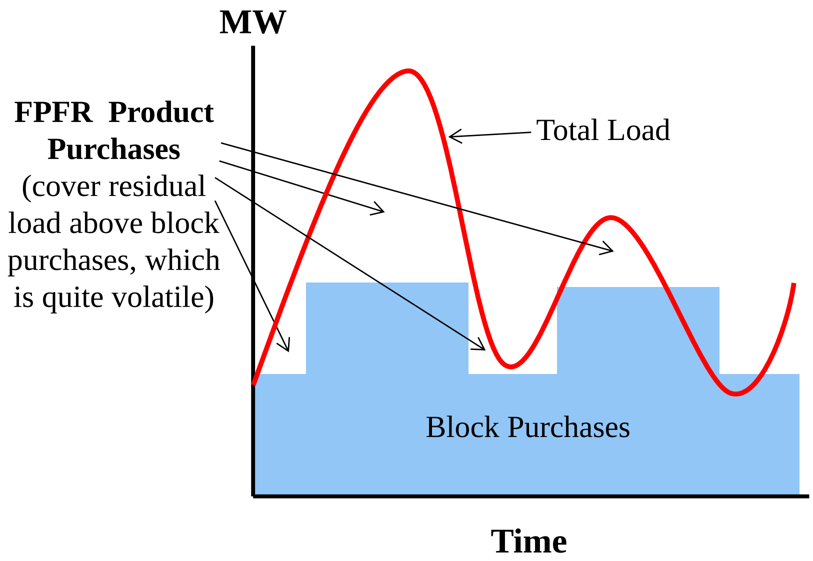
### F. The IPA Does Not Appear to Consider the Most Likely Way That FPFR Products Would Be Defined and Integrated into the Existing Supply Portfolio

Another reason why the IPA's rejection of the integration of FPFR products into the IPA Plan is invalid is the fact that the IPA does not appear to consider the most likely way that such products would be defined and integrated into the existing supply portfolio. Specifically, the IPA's rejection of the concept of integrating FPFR products into the supply portfolio is at least in part based on an assumption that the FPFR products would be defined in such a way that the FPFR product suppliers would be required to serve only the residual load requirements (above the volumes of the supply products already purchased):

> *The IPA is not prepared to recommend the use of full requirements products. Accounting for the volumes of already-contracted forward hedges, the risk of each full requirements tranche will be increased. The full requirements contracts would only cover residual load (relative to the existing hedges) but would bear all the load risk. This creates a great deal of uncertainty in the determination of the reasonableness of their pricing.*[59]

Clearly, the IPA appears to assume that FPFR product suppliers would serve only the residual load requirement, in other words the load requirement net of the volumes of the block products purchased, as shown below.

[59] 2014 Draft IPA Plan, at 89.




This approach would require the FPFR product suppliers to bear the entire load risk while only serving the residual load, and is unlike FPFR products in place in many other jurisdictions.[60] Not surprisingly, the IPA concludes that under these conditions the FPFR product prices could be high and that it would be difficult to assess their reasonableness.[61] However, this conceptualization of how the FPFR products would be defined and integrated entirely overlooks the arguably more manageable way to define the FPFR products and integrate them into the supply portfolio. Specifically, the FPFR products could be designed like those in almost every other jurisdiction, in which the FPFR product suppliers must serve a (pro-rata) cross-section[62] of the entire actual load requirement. The remaining cross-section would be supplied through the block-and-spot approach (i.e., the residual load requirements, above the supply product quantities, would be satisfied through purchases and sales in the spot market, as they are now). As shown below, this approach effectively separates the load into two portions: one that is entirely supplied by the block-and-spot approach and one that is entirely supplied by FPFR products.

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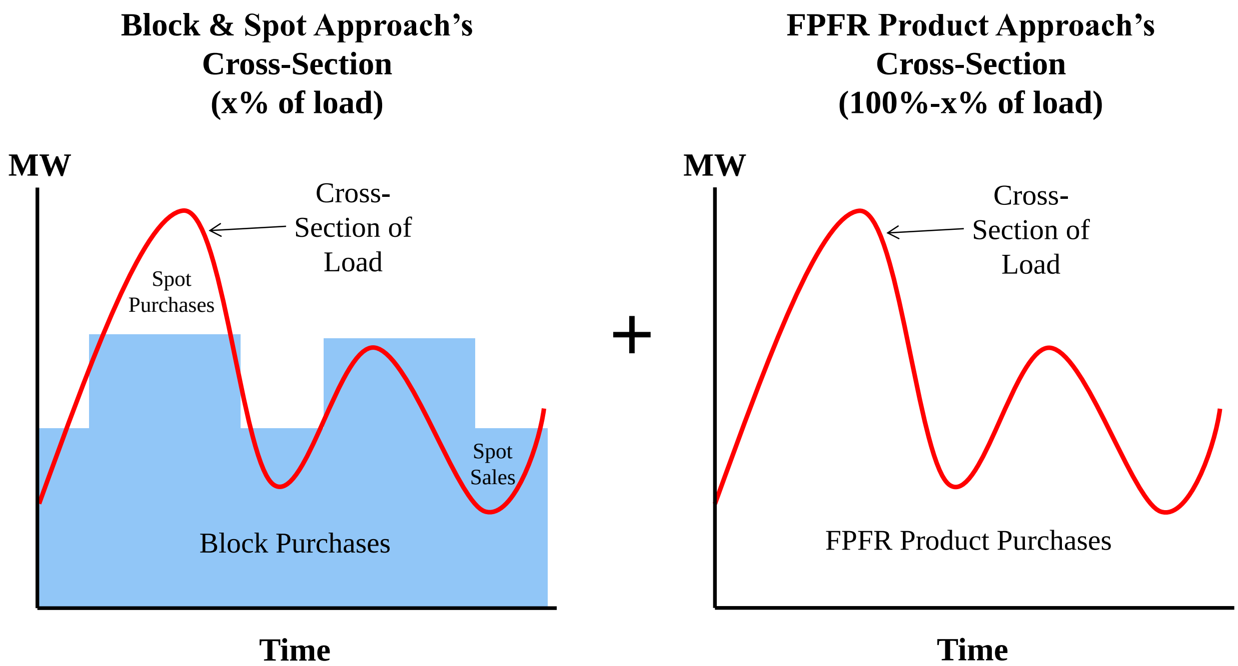
[60] Technically speaking, in some other jurisdictions, the FPFR product's supply requirement may be net of a very small amount of separately contracted supply.

[61] 2014 Draft IPA Plan, at 89.

[62] Technically speaking, in some other jurisdictions, the FPFR product's supply requirement may be net of a very small amount of separately contracted supply.




Under this approach, FPFR product suppliers serve a cross-section of the entire actual load requirement and not just the residual load requirement. This method has several benefits relative to the method suggested by the IPA. First, it should be fairly simple to implement. The portion of the load to be supplied by FPFR products would be a fixed percentage share of the entire actual hourly load requirement and therefore it would allow for FPFR products that are structurally similar to those solicited elsewhere. Meanwhile, the portion of the load to be supplied by the block-and-spot approach could operate exactly like that proposed by the IPA, but the overall supply quantities would be scaled down to accommodate the portion of the load that is supplied by FPFR products. Second, by not requiring FPFR product suppliers to bear the entire load risk while only serving a "residual" load ("above" or "on top of" block products), the prices of the FPFR products would be reduced. Third, because the FPFR products would supply a cross-section of the load, their prices could more easily be compared to expectations about the market costs of various components of the FPFR supply obligation as of the times of the FPFR product solicitations.[63]

### G. Suggestions Made by the IPA Regarding the Uncertainty about FPFR Product Pricing Are Inaccurate or Easily Could Be Misunderstood

Finally, a couple of suggestions made by the IPA regarding the uncertainty about FPFR product

[63] Any such assessment must consider expectations as of the times of the FPFR product solicitations. It would be inappropriate to pass judgment on any procurement approach based solely on a measurement of its costs during the single market scenario that unfolded in the past; instead, we should assess how the approach would perform in the future, with a consideration for, and an informed understanding of, the many different possible market scenarios that could unfold. Similarly, people generally do not decide to reject health insurance for their family because they didn't get sick in a particular past period.

pricing must be addressed. Specifically, in the 2014 Draft IPA Plan, the IPA observes historical prices for Public Service Electric & Gas's ("PSE&G") FPFR products obtained through New Jersey's FPFR product auctions and compares each of the FPFR product prices to the straight average hourly spot energy prices that ultimately settled during the given FPFR product's delivery period. The IPA then makes suggestions about FPFR product pricing that are inaccurate or that easily could be misunderstood.

The first such suggestion is that the difference between the FPFR product price and the average hourly spot energy price is the "full requirements premium."[64] The term, "premium," is sometimes used in the context of FPFR products to refer to profit margin required by the FPFR product supplier above its expectation of its all-in cost to satisfy all of the obligations of the FPFR product. In fact, on a different page of the 2014 Draft IPA Plan, the IPA uses the term, "premium," in this context, as it states, "A full requirements supplier is assumed to charge a premium over the expected cost of its obligation."[65] For the purposes of clarity, it is critical to note that the difference between the FPFR product price and the average energy price corresponding to the delivery period does not represent a FPFR product supplier's profit margin over its expected cost. Instead, this difference is driven by many other costs associated with the obligation to supply customers' load requirements, such as the costs of capacity, load following energy (i.e., due to correlations between market prices and loads, the cost to supply customer load requirements is generally higher than the average hourly market price), ancillary services, satisfaction of alternative energy portfolio standards, and in the case of the PSE&G FPFR products, network transmission service. This is not meant to be an exhaustive list, but it shows that the FPFR product price is designed to cover other very real costs and risks, so the difference referenced by the IPA certainly is not a likely profit margin.

The second suggestion made by the IPA that must be addressed is that the higher difference (between PSE&G's FPFR product price and the straight average hourly spot energy price that ultimately settled during the given product's delivery period) starting with the FPFR product procured in 2006 was driven by FPFR product suppliers recalibrating the risks that the FPFR products require them to bear.[66] It is true that the compensation required by FPFR product suppliers to directly bear costs and risks (such as the additional costs and risks driven by the prospect of customer switching) to customers' benefit will change over time to the degree that the costs and risks change, and that customers directly bear these costs and risks when a block-and-spot approach is employed instead. It is also true that assessments of the costs and risks, and therefore the compensation required by FPFR product suppliers to bear these costs and risks, may have evolved over time as FPFR products and markets became more established. However, the IPA's suggestion that the higher difference, starting with the FPFR product procured in 2006, was fully due to a reassessment by FPFR product suppliers of the additional risks that they bear, is inaccurate. In fact, the increase in the difference was very likely primarily driven by increases in the costs of basic supply components included in the FPFR product obligation:

[64] 2014 Draft IPA Plan, at 70-71.

[65] 2014 Draft IPA Plan, at 72.

[66] 2014 Draft IPA Plan, at 71.

- Significant increases in forward energy prices as of 2006 versus as of 2005 – In order to assess FPFR product prices in relation to the costs of the underlying supply components, one must examine market price information available to bidders at the time that the bids were submitted. The IPA's analysis does not do this, as its proxy for the market cost of energy is the average of the hourly spot prices of energy, which were settled during a time period stretching over three years after the respective FPFR product bids were submitted. Instead, the IPA should have referenced the forward energy prices as of the time that the bidding occurred, as a proxy for the appropriate market cost of energy. For example, NYMEX on-peak energy futures prices for delivery at the nearby PJM Western Hub increased by about 50% between the 2005 FPFR product bid date and the 2006 FPFR product bid date.[67,68] This change in market price expectations clearly was a driver of the increase in the FPFR product bid price from 2005 to 2006.

- Implementation of the RPM capacity market – PJM implemented its Reliability Pricing Model in 2007, with new capacity prices effective June 1, 2007. The new RPM capacity prices for the PSE&G service area represented a substantial increase over previous capacity prices, due to both the RPM structure and the fact that RPM reflects the relatively limited transmission capacity into the PSE&G service area. During the 2005-2006 period, market participants were assessing the likely impact of RPM implementation on capacity prices; this, combined with the fact that only one-third of the delivery period of the "2005" FPFR product price on the graph corresponds to a period in which RPM capacity prices were effective, while two-thirds of the delivery period of the "2006" FPFR product price on the graph corresponds to a period in which RPM capacity prices were effective, is also a contributor to the increase in the FPFR product bid price after 2005.

- Increase in alternative energy portfolio standard requirements – The amount of renewable energy credits that must be purchased relative to the load served has increased over time, and all else equal this also increases the costs to serve load.

### H. Relevant and Comprehensive Analyses of Regions Outside of Illinois, Where Observable Data about Actual FPFR Product Pricing and Supply Costs and Risks Is Available, Indicate That the Compensation Required by FPFR Product Suppliers Is Reasonable Given the Costs and Risks That They Directly Bear to the Benefit of Customers

As described above, the IPA's analysis suffers from significant shortcomings that make it unable to provide useful information regarding the relative merits of the FPFR product approach as compared to the block-and-spot approach. In contrast, the NorthBridge Group has performed Monte Carlo simulation analyses that do not suffer from these shortcomings. While these analyses study regions outside of Illinois, they are very useful because they use actual

[67] As of February 11, 2005, the NYMEX futures price for calendar year 2007 on-peak delivery at the PJM Western Hub was $54.85/MWH. As of February 7, 2006, the NYMEX futures price for calendar year 2007 on-peak delivery at the PJM Western Hub was $82.33/MWH. Market price data was provided by Ventyx / Energy Velocity.

[68] Visible forward prices for the PSE&G service area as of 2005 and 2006 are not available.

observable data about FPFR product pricing and the supply costs and risks within the regions studied. The most recent of these studies was performed in 2012 for PECO Energy Company ("PECO"). This analysis relates to the choice of supply strategy for PECO's residential default service load, and it was presented on behalf of PECO in the Pennsylvania Public Utility Commission proceeding to determine the choice of default service supply approach for PECO.[69] The PECO analysis uses relevant data that was amply available, as both the block-and-spot approach and the FPFR product approach were simultaneously employed to supply portions of the load requirements of PECO's residential default service customers at the time of the analysis. Currently, the block-and-spot approach is being phased out in PECO's service area because the Pennsylvania Public Utility Commission ordered the phase out in its final order in the proceeding in which the PECO analysis was presented.[70]

Admittedly, the costs and risks borne by FPFR product suppliers may vary from one jurisdiction to the next. Generally speaking, the higher the risk of unanticipated market price or load movements, the greater the value of the protection against adverse risks that the FPFR products provide. While uncertainty about residential and small non-residential customer switching may be higher in Illinois than it is in PECO's service area, PECO's service area has active customer switching, with over one-third of residential customer load currently being served by ARES,[71] and furthermore any differences in customer switching risks are no reason to assume that the basic conclusions about the tradeoff between the block-and-spot approach and the FPFR product approach would change. If uncertainty about customer switching is higher in Illinois, then the compensation required by Illinois FPFR product suppliers to bear resultant higher costs and risks to the benefit of customers will be higher, but the costs and risks that would be borne by Illinois customers under the block-and-spot approach also will be higher, so this does not justify rejection of the FPFR product approach in Illinois.

The PECO analysis involves the application of different default service approaches to 1,000 different but equally likely market scenarios[72] that reflect complex real-world market dynamics, consistent with the volatilities, correlations, and mean reversion of market price and load changes observed historically. A representative 100% FPFR product approach ("FPFR Product Approach") was analyzed.[73] An analogous block-and-spot approach ("Block-and-Spot Approach with 80% Target") also was analyzed. In this block-and-spot approach, block products (with quantities that differ by monthly on-peak/off-peak period) covering the same time periods that the FPFR products cover (in the FPFR Product Approach) are procured (at the same times that the FPFR products are procured in the FPFR Product Approach), with targeted

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[69] PECO Energy Company Statement No. 3-R, Pennsylvania Public Utility Commission Docket No. P-2012-2283641 (Petition of PECO Energy Company for Approval of Its Default Service Program II), May 4, 2012.

[70] Petition of PECO Energy Company for Approval of Its Default Service Program II, Pennsylvania Public Utility Commission, Docket No. P-2012-2283641 (Order entered October 12, 2012), at 12-17.

[71] "Pennsylvania Electric Shopping Statistics, July 1, 2013," PA Office of Consumer Advocate.

[72] In this context, a "scenario" is a potential state-of-the-world that may unfold. Each scenario includes a trajectory for how forward prices for energy may vary over time, what spot prices might result, how customer load may vary, and what the cost to serve customers will be.

[73] In the FPFR Product Approach, 60% of the supply comprises two-year products, and 40% comprises one-year products, with solicitations occurring semiannually and delivery periods overlapping semiannually.

block quantities reflecting 80% of the expected default service load obligation. Another block-and-spot approach ("Block-and-Spot Approach with 106% Target") has since been analyzed. This block-and-spot approach is more closely aligned with the IPA's recommendation regarding the block quantities to procure relative to load expectations. Specifically, in this block-and-spot approach, block products (with quantities that differ by monthly on-peak/off-peak period) covering the same time periods that the FPFR products cover (in the FPFR Product Approach) are procured (at the same times that the FPFR products are procured in the FPFR Product Approach), with targeted block quantities reflecting 106% of the expected default service load obligation.[74] While the specific product mixes in each approach may differ from some specific product mixes that could have been chosen, the results of these different approaches can be used to derive useful insights regarding the general tradeoff between the FPFR product approach and the block-and-spot approach. The analysis entails applying each default service approach to be analyzed to each of the 1,000 scenarios, procuring products, setting rates, calculating actual costs, and amortizing over/under recoveries as appropriate. In order to develop insight regarding the costs and risks associated with any given default service approach, the performance of the approach across the scenarios can be assessed against various predetermined "metrics" that characterize aspects of costs and risks that are of concern. The metrics include:

- Expected Default Service Supply Rate Level – Average default service supply rate across all scenarios.

- Default Service Rate Shock – Distribution of maximum rate change over a given period of time (e.g., looking across a year, what is the largest increase in the rate versus what it was six months earlier).

- Default Service Supply Cost Surprise – Distribution of difference between actual (ex-post) and forecasted (ex-ante) supply costs (e.g., how do actual supply costs over a twelve-month period compare to expectations three months before that period began).

- Deferred Cost Recovery Balance – Distribution of accumulated under/(over) recoveries due to differences between default service rates and actual supply costs.

The attractiveness of various default service approaches can be compared by studying how each performs against the various metrics.

The principal findings of the analysis are twofold. First, the analysis indicates that a block-and-spot approach exposes customers to considerably more risk with regard to rate volatility, supply cost uncertainty, and deferred cost recovery balances than a FPFR product approach does. Second, the analysis indicates that a block-and-spot approach does not involve significantly lower expected default service rates, relative to the risks to which customers are exposed in a block-and-spot approach. In other words, the analysis indicates that the compensation that FPFR product suppliers require to directly bear costs and risks to the benefit of customers is

[74] In the analysis of each of the three approaches (the "FPFR Product Approach," the "Block-and-Spot Approach with 80% Target," and the "Block-and-Spot Approach with 106% Target"), the analysis is pure in that it does not incorporate legacy or shorter-term plan transition contracts.

reasonable. The tables below show how the two block-and-spot approaches compare with the FPFR Product Approach.

**"Block-and-Spot Approach with 80% Target" vs. "FPFR Product Approach"**

| Default Service Approach[75] | Expected Default Service Supply Rate Level[76] ($/MWH) | Default Service Rate Shock[77] ($/MWH) | Default Service Supply Cost Surprise[78] ($/MWH) | Deferred Cost Recovery Balance[79] ($MM) |
|---|---|---|---|---|
| FPFR Product Approach | $62.31 | $8.26 | $2.75 | $0 |
| Block-and-Spot Approach with 80% Target | $60.62 | $18.45 | $10.12 | $120 |
| Increase in Risk ($/MWH or $MM) | | $10.19 (+123%) | $7.37 (+268%) | $120 |
| Decrease in Expected Rate ($/MWH) | $1.69 (2.7%) | | | |

[75] Consistent with general market price levels for the PECO service area at the time of the analysis, the scenarios to which each default service approach is applied reflect an average ATC energy price of $40/MWH, an average capacity price of $13/MWH, and an average 15 million megawatt-hours per year of total (default service plus ARES) residential load.

[76] The values shown are the "expected" values (i.e., the average value across the 1,000 scenarios). Dollar-per-megawatt-hour values are not grossed up for line losses, retail taxes, or any approved adders that are required to cover administrative costs.

[77] The values shown are the "top decile" values (i.e., the average value across the ten percent of scenarios, or equivalently the 100 scenarios, with the highest values). Dollar-per-megawatt-hour values are not grossed up for line losses, retail taxes, or any approved adders that are required to cover administrative costs.

[78] The values shown are the "top decile" values (i.e., the average value across the ten percent of scenarios, or equivalently the 100 scenarios, with the highest values). Dollar-per-megawatt-hour values are not grossed up for line losses, retail taxes, or any approved adders that are required to cover administrative costs.

[79] The values shown are the "top decile" values (i.e., the average value across the ten percent of scenarios, or equivalently the 100 scenarios, with the highest values). The analysis does not account for cyclical deferred costs due to the difference between calendar months and billing months. This source of deferred cost exists under either default service approach.

**“Block-and-Spot Approach with 106% Target” vs. “FPFR Product Approach”**

| Default Service Approach | Expected Default Service Supply Rate Level ($/MWH) | Default Service Rate Shock ($/MWH) | Default Service Supply Cost Surprise ($/MWH) | Deferred Cost Recovery Balance ($MM) |
|---|---|---|---|---|
| FPFR Product Approach | $62.31 | $8.26 | $2.75 | $0 |
| Block-and-Spot Approach with 106% Target | $62.18 | $13.37 | $7.40 | $80 |
| Increase in Risk ($/MWH or $MM) | | $5.11 (+62%) | $4.65 (+169%) | $80 |
| Decrease in Expected Rate ($/MWH) | $0.13 (0.2%) | | | |

As the tables indicate, a block-and-spot approach involves higher levels of risk along several dimensions. Top decile rate shocks are between 62% and 123% greater under the block-and-spot approaches than they are under the FPFR Product Approach. Similarly, the top decile values for supply cost surprise are between 169% and 268% higher, reflecting the fact that block products are for fixed volumes of supply and do not provide price certainty when default service load volumes vary from the block product volumes purchased. In addition, the incorporation of block-and-spot purchases in the supply portfolio results in actual supply costs that are not known until after default service rates have been set; consequently, the block-and-spot approaches involve the potential for significant deferred cost recovery balances ($80-$120 million as measured on a top decile basis). Finally, it is important to recognize that the actual outcomes with regard to the metrics described above could exceed the values in the table, because the values in the table are the “top decile” values (i.e., the average of the top 10% of values across the scenarios). Stated simply, there are certainly potential outcomes even more extreme than the top decile values shown.

These increases in risk to customers are not balanced by a proportionate decrease in the expected default service rate level. On the contrary, the expected default service supply rate levels under the block-and-spot approaches are only $0.13-$1.69 per megawatt-hour, or 0.2%-2.7%, less than under the safer FPFR Product Approach.

Finally, it is important to note that, while the pricing of FPFR products is fully represented in the analysis, there are additional costs and risks that are experienced under a block-and-spot approach that are not captured by the analysis. For example, when evaluating the block-and-spot approaches, imputed debt costs as well as uncertainty regarding the costs of ancillary services and alternative energy portfolio standards are not included. Under the block-and-spot approach, customers are fully exposed to the uncertainty associated with these costs while, under the FPFR product approach, customers are provided some insulation from this uncertainty because customers pay a predetermined fixed rate for load-following supply during the entire delivery period of the FPFR product. Furthermore, changes in market rules or legislation also can contribute to the costs and risks of the block-and-spot approach. Finally, there may be additional risks that we cannot anticipate, from which the fixed-price guarantee associated with the FPFR product would protect customers, but block-and-spot purchases, which do not provide such a guarantee, would not.

## IV. Conclusion

The prospect of continuing with a full block-and-spot procurement approach is particularly troubling, especially in light of the Competition Act's finding that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[80] As has been explained and supported with evidence from recent Illinois supply costs, the block-and-spot approach can result in additional costs, risks, instability, and perverse outcomes for customers. In contrast, the FPFR product approach protects customers from these risks. The IPA's conclusions about the relative merits of these two supply approaches are invalidated by significant shortcomings in its analysis and its apparent failure to consider the most likely way that FPFR products would be integrated into the existing supply portfolio. However, an analysis that pertains to a region in which both supply approaches simultaneously had been implemented indicates that FPFR product pricing is reasonable given the costs and risks that FPFR product suppliers directly bear to the benefit of customers. Given this evidence of the benefits of FPFR products and the fact that these benefits are widely recognized in other restructured jurisdictions, FPFR products should be included in the IPA Plan. To the extent that these products are included, they will protect customers from the proven adverse risks of the block-and-spot approach, and more information will be gained about their pricing in the context of the Illinois electricity markets.

[80] 20 ILCS 3855/1-5(1).

# Appendix A

**Replication of Underlying Energy Cost in June 2012 - May 2013 ComEd PEP**

**Expected Energy (MW)**

| | On-Peak Period Energy (MW) | | | | | | Off-Peak Period Energy (MW) | | | | | | Hours | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Residual | Total Load | Swap | LT Renew | 2011 RFP | 2012 RFP | Residual | Total Load | On-Peak | Off-Peak |
| Jun-12 | 3,000 | 94 | 600 | 500 | 66 | 4,260 | 3,000 | 106 | 0 | 300 | 47 | 3,453 | 336 | 384 |
| Jul-12 | 3,000 | 61 | 1,500 | 200 | 107 | 4,868 | 3,000 | 80 | 600 | 150 | 88 | 3,918 | 336 | 408 |
| Aug-12 | 3,000 | 61 | 1,150 | 0 | (126) | 4,085 | 3,000 | 109 | 300 | 0 | (124) | 3,285 | 368 | 376 |
| Sep-12 | 3,000 | 97 | 0 | 0 | (278) | 2,819 | 3,000 | 97 | 0 | 0 | (733) | 2,364 | 304 | 416 |
| Oct-12 | 3,000 | 150 | 0 | 0 | (846) | 2,304 | 3,000 | 180 | 0 | 0 | (1,259) | 1,921 | 368 | 376 |
| Nov-12 | 3,000 | 178 | 0 | 0 | (771) | 2,407 | 3,000 | 204 | 0 | 0 | (1,155) | 2,049 | 336 | 384 |
| Dec-12 | 3,000 | 162 | 0 | 0 | (369) | 2,793 | 3,000 | 140 | 0 | 0 | (702) | 2,438 | 320 | 424 |
| Jan-13 | 3,000 | 164 | 0 | 0 | (343) | 2,821 | 3,000 | 180 | 0 | 0 | (686) | 2,494 | 352 | 392 |
| Feb-13 | 3,000 | 152 | 0 | 0 | (572) | 2,580 | 3,000 | 167 | 0 | 0 | (863) | 2,304 | 320 | 352 |
| Mar-13 | 3,000 | 174 | 0 | 0 | (916) | 2,258 | 3,000 | 194 | 0 | 0 | (1,193) | 2,001 | 336 | 408 |
| Apr-13 | 3,000 | 188 | 0 | 0 | (1,215) | 1,973 | 3,000 | 205 | 0 | 0 | (1,505) | 1,700 | 352 | 368 |
| May-13 | 3,000 | 187 | 0 | 0 | (1,240) | 1,947 | 3,000 | 168 | 0 | 0 | (1,529) | 1,639 | 352 | 392 |
| Total | | | | | | | | | | | | | 4,080 | 4,680 |

**Expected Energy (GWH)**

| | On-Peak Period Energy (MWH) | | | | | | Off-Peak Period Energy (MWH) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Total Load | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Total Load |
| Jun-12 | 1,008 | 32 | 202 | 168 | 22 | 1,431 | 1,152 | 41 | 0 | 115 | 18 | 1,326 |
| Jul-12 | 1,008 | 20 | 504 | 67 | 36 | 1,636 | 1,224 | 33 | 245 | 61 | 36 | 1,599 |
| Aug-12 | 1,104 | 22 | 423 | 0 | (46) | 1,503 | 1,128 | 41 | 113 | 0 | (47) | 1,235 |
| Sep-12 | 912 | 29 | 0 | 0 | (84) | 857 | 1,248 | 40 | 0 | 0 | (305) | 984 |
| Oct-12 | 1,104 | 55 | 0 | 0 | (311) | 848 | 1,128 | 68 | 0 | 0 | (474) | 722 |
| Nov-12 | 1,008 | 60 | 0 | 0 | (259) | 809 | 1,152 | 78 | 0 | 0 | (443) | 787 |
| Dec-12 | 960 | 52 | 0 | 0 | (118) | 894 | 1,272 | 59 | 0 | 0 | (298) | 1,034 |
| Jan-13 | 1,056 | 58 | 0 | 0 | (121) | 993 | 1,176 | 71 | 0 | 0 | (269) | 978 |
| Feb-13 | 960 | 49 | 0 | 0 | (183) | 826 | 1,056 | 59 | 0 | 0 | (304) | 811 |
| Mar-13 | 1,008 | 58 | 0 | 0 | (308) | 759 | 1,224 | 79 | 0 | 0 | (487) | 817 |
| Apr-13 | 1,056 | 66 | 0 | 0 | (428) | 695 | 1,104 | 75 | 0 | 0 | (554) | 626 |
| May-13 | 1,056 | 66 | 0 | 0 | (436) | 685 | 1,176 | 66 | 0 | 0 | (599) | 643 |
| Total | 12,240 | 568 | 1,129 | 235 | (2,237) | 11,935 | 14,040 | 710 | 358 | 176 | (3,724) | 11,560 |
| Summer | | | | | | 5,427 | | | | | | 5,143 |
| Non-Summer | | | | | | 6,508 | | | | | | 6,416 |

**Energy Price ($/MWH)**

| | On-Peak Period Energy Price ($/MWH) | | | | | | | Off-Peak Period Energy Price ($/MWH) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Forward | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up % | Forward | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up % |
| Jun-12 | 32.52 | 52.37 | 32.52 | 42.51 | 34.55 | 32.52 | 8.0% | 20.96 | 52.37 | 20.96 | | 21.73 | 20.96 | 12.1% |
| Jul-12 | 39.19 | 52.37 | 39.19 | 51.65 | 41.00 | 39.19 | 7.1% | 23.69 | 52.37 | 23.69 | 27.91 | 24.91 | 23.69 | 13.0% |
| Aug-12 | 39.23 | 52.37 | 39.23 | 51.18 | | 39.23 | 9.8% | 23.69 | 52.37 | 23.69 | 27.72 | | 23.69 | 9.5% |
| Sep-12 | 30.08 | 52.37 | 30.08 | | | 30.08 | 7.3% | 19.45 | 52.37 | 19.45 | | | 19.45 | 11.5% |
| Oct-12 | 30.02 | 52.37 | 30.02 | | | 30.02 | 1.6% | 20.59 | 52.37 | 20.59 | | | 20.59 | 5.5% |
| Nov-12 | 30.00 | 52.37 | 30.00 | | | 30.00 | 2.4% | 20.62 | 52.37 | 20.62 | | | 20.62 | 4.4% |
| Dec-12 | 30.03 | 52.37 | 30.03 | | | 30.03 | 4.7% | 20.65 | 52.37 | 20.65 | | | 20.65 | 6.0% |
| Jan-13 | 36.58 | 53.48 | 36.58 | | | 36.58 | 5.1% | 24.45 | 53.48 | 24.45 | | | 24.45 | 8.0% |
| Feb-13 | 36.59 | 53.48 | 36.59 | | | 36.59 | 4.5% | 24.45 | 53.48 | 24.45 | | | 24.45 | 4.4% |
| Mar-13 | 33.58 | 53.48 | 33.58 | | | 33.58 | 3.0% | 22.42 | 53.48 | 22.42 | | | 22.42 | 5.6% |
| Apr-13 | 33.56 | 53.48 | 33.56 | | | 33.56 | 1.4% | 22.44 | 53.48 | 22.44 | | | 22.44 | 6.6% |
| May-13 | 34.06 | 53.48 | 34.06 | | | 34.06 | 6.2% | 22.73 | 53.48 | 22.73 | | | 22.73 | 12.2% |

**Underlying Energy Cost ($MM)**

| | On-Peak Period Energy Cost ($MM) | | | | | | | Off-Peak Period Energy Cost ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up | Total | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up | Total |
| Jun-12 | 52.79 | 1.03 | 8.57 | 5.80 | 0.72 | 3.72 | 72.6 | 60.33 | 0.85 | - | 2.50 | 0.38 | 3.37 | 67.4 |
| Jul-12 | 52.79 | 0.80 | 26.03 | 2.76 | 1.40 | 4.58 | 88.4 | 64.10 | 0.77 | 6.83 | 1.52 | 0.85 | 4.94 | 79.0 |
| Aug-12 | 57.82 | 0.88 | 21.66 | - | (1.82) | 5.75 | 84.3 | 59.07 | 0.97 | 3.13 | - | (1.11) | 2.79 | 64.8 |
| Sep-12 | 47.76 | 0.89 | - | - | (2.54) | 1.87 | 48.0 | 65.36 | 0.78 | - | - | (5.93) | 2.20 | 62.4 |
| Oct-12 | 57.82 | 1.66 | - | - | (9.35) | 0.41 | 50.5 | 59.07 | 1.39 | - | - | (9.75) | 0.82 | 51.5 |
| Nov-12 | 52.79 | 1.79 | - | - | (7.78) | 0.59 | 47.4 | 60.33 | 1.62 | - | - | (9.14) | 0.71 | 53.5 |
| Dec-12 | 50.28 | 1.56 | - | - | (3.55) | 1.27 | 49.6 | 66.61 | 1.23 | - | - | (6.15) | 1.28 | 63.0 |
| Jan-13 | 56.47 | 2.11 | - | - | (4.41) | 1.84 | 56.0 | 62.89 | 1.73 | - | - | (6.57) | 1.92 | 60.0 |
| Feb-13 | 51.34 | 1.78 | - | - | (6.69) | 1.36 | 47.8 | 56.47 | 1.44 | - | - | (7.43) | 0.87 | 51.4 |
| Mar-13 | 53.91 | 1.96 | - | - | (10.33) | 0.78 | 46.3 | 65.46 | 1.77 | - | - | (10.91) | 1.03 | 57.4 |
| Apr-13 | 56.47 | 2.22 | - | - | (14.35) | 0.33 | 44.7 | 59.04 | 1.69 | - | - | (12.43) | 0.92 | 49.2 |
| May-13 | 56.47 | 2.24 | - | - | (14.86) | 1.45 | 45.3 | 62.89 | 1.50 | - | - | (13.62) | 1.78 | 52.5 |
| Total | 646.7 | 18.9 | 56.3 | 8.6 | (73.6) | 23.9 | 680.8 | 741.6 | 15.7 | 10.0 | 4.0 | (81.8) | 22.6 | 712.2 |
| Summer | | | | | | | 293.3 | | | | | | | 273.7 |
| Non-Summer | | | | | | | 387.6 | | | | | | | 438.5 |

**Total Underlying Energy Cost ($/MWh)**

| | |
|---|---|
| Summer Peak | 54.03 |
| Summer Off-Peak | 53.22 |
| Non-Summer Peak | 59.56 |
| Non-Summer Off-Peak | 68.34 |
| Total | 59.29 |

# Appendix B

**Underlying Energy Cost in June 2012 - May 2013 ComEd PEP If Contracts Scaled with the Load**

| | |
|---|---|
| Upcoming Plan Year +1 Hedge Target: | 70% |
| Upcoming Plan Year Hedge Target: | 100% |
| Block Product Hedge Granularity (MW): | 50 |

**Expected Energy (MW)**

| | On-Peak Period Energy (MW) | | | | | | Off-Peak Period Energy (MW) | | | | | | Hours | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Residual | Total Load | Swap | LT Renew | 2011 RFP | 2012 RFP | Residual | Total Load | On-Peak | Off-Peak |
| Jun-12 | 1,970 | 59 | 950 | 1,300 | (19) | 4,260 | 1,970 | 66 | 400 | 1,000 | 17 | 3,453 | 336 | 384 |
| Jul-12 | 1,970 | 38 | 1,400 | 1,450 | 9 | 4,868 | 1,970 | 50 | 700 | 1,200 | (2) | 3,918 | 336 | 408 |
| Aug-12 | 1,970 | 38 | 850 | 1,250 | (24) | 4,085 | 1,970 | 68 | 250 | 1,000 | (4) | 3,285 | 368 | 376 |
| Sep-12 | 1,970 | 61 | 0 | 800 | (12) | 2,819 | 1,970 | 61 | 0 | 350 | (16) | 2,364 | 304 | 416 |
| Oct-12 | 1,970 | 94 | 0 | 250 | (10) | 2,304 | 1,970 | 112 | 0 | 0 | (162) | 1,921 | 368 | 376 |
| Nov-12 | 1,970 | 111 | 0 | 350 | (25) | 2,407 | 1,970 | 127 | 0 | 0 | (48) | 2,049 | 336 | 384 |
| Dec-12 | 1,970 | 101 | 0 | 700 | 21 | 2,793 | 1,970 | 87 | 0 | 400 | (20) | 2,438 | 320 | 424 |
| Jan-13 | 1,970 | 102 | 0 | 750 | (1) | 2,821 | 1,970 | 112 | 0 | 400 | 12 | 2,494 | 352 | 392 |
| Feb-13 | 1,970 | 95 | 0 | 500 | 15 | 2,580 | 1,970 | 104 | 0 | 250 | (21) | 2,304 | 320 | 352 |
| Mar-13 | 1,970 | 109 | 0 | 200 | (21) | 2,258 | 1,970 | 121 | 0 | 0 | (90) | 2,001 | 336 | 408 |
| Apr-13 | 1,970 | 117 | 0 | 0 | (114) | 1,973 | 1,970 | 128 | 0 | 0 | (399) | 1,700 | 352 | 368 |
| May-13 | 1,970 | 117 | 0 | 0 | (140) | 1,947 | 1,970 | 105 | 0 | 0 | (436) | 1,639 | 352 | 392 |
| Total | | | | | | | | | | | | | 4,080 | 4,680 |

**Expected Energy (GWH)**

| | On-Peak Period Energy (MWH) | | | | | | Off-Peak Period Energy (MWH) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Total Load | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Total Load |
| Jun-12 | 662 | 20 | 319 | 437 | (6) | 1,431 | 757 | 25 | 154 | 384 | 7 | 1,326 |
| Jul-12 | 662 | 13 | 470 | 487 | 3 | 1,636 | 804 | 20 | 286 | 490 | (1) | 1,599 |
| Aug-12 | 725 | 14 | 313 | 460 | (9) | 1,503 | 741 | 26 | 94 | 376 | (1) | 1,235 |
| Sep-12 | 599 | 18 | 0 | 243 | (4) | 857 | 820 | 25 | 0 | 146 | (7) | 984 |
| Oct-12 | 725 | 34 | 0 | 92 | (4) | 848 | 741 | 42 | 0 | 0 | (61) | 722 |
| Nov-12 | 662 | 37 | 0 | 118 | (8) | 809 | 757 | 49 | 0 | 0 | (19) | 787 |
| Dec-12 | 631 | 32 | 0 | 224 | 7 | 894 | 835 | 37 | 0 | 170 | (8) | 1,034 |
| Jan-13 | 694 | 36 | 0 | 264 | (1) | 993 | 772 | 44 | 0 | 157 | 5 | 978 |
| Feb-13 | 631 | 30 | 0 | 160 | 5 | 826 | 694 | 37 | 0 | 88 | (7) | 811 |
| Mar-13 | 662 | 36 | 0 | 67 | (7) | 759 | 804 | 49 | 0 | 0 | (37) | 817 |
| Apr-13 | 694 | 41 | 0 | 0 | (40) | 695 | 725 | 47 | 0 | 0 | (147) | 626 |
| May-13 | 694 | 41 | 0 | 0 | (49) | 685 | 772 | 41 | 0 | 0 | (171) | 643 |
| Total | 8,039 | 354 | 1,102 | 2,552 | (113) | 11,935 | 9,221 | 443 | 533 | 1,810 | (447) | 11,560 |
| Summer | | | | | | 5,427 | | | | | | 5,143 |
| Non-Summer | | | | | | 6,508 | | | | | | 6,416 |

**Energy Price ($/MWH)**

| | On-Peak Period Energy Price ($/MWH) | | | | | | | Off-Peak Period Energy Price ($/MWH) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Forward | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up % | Forward | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up % |
| Jun-12 | 32.52 | 52.37 | 32.52 | 42.51 | 34.55 | 32.52 | 8.0% | 20.96 | 52.37 | 20.96 | 24.07 | 21.73 | 20.96 | 12.1% |
| Jul-12 | 39.19 | 52.37 | 39.19 | 51.65 | 41.00 | 39.19 | 7.1% | 23.69 | 52.37 | 23.69 | 27.91 | 24.91 | 23.69 | 13.0% |
| Aug-12 | 39.23 | 52.37 | 39.23 | 51.18 | 41.36 | 39.23 | 9.8% | 23.69 | 52.37 | 23.69 | 27.72 | 24.74 | 23.69 | 9.5% |
| Sep-12 | 30.08 | 52.37 | 30.08 | 39.77 | 31.72 | 30.08 | 7.3% | 19.45 | 52.37 | 19.45 | 22.49 | 20.30 | 19.45 | 11.5% |
| Oct-12 | 30.02 | 52.37 | 30.02 | 38.36 | 31.65 | 30.02 | 1.6% | 20.59 | 52.37 | 20.59 | 21.61 | 21.50 | 20.59 | 5.5% |
| Nov-12 | 30.00 | 52.37 | 30.00 | 38.34 | 31.63 | 30.00 | 2.4% | 20.62 | 52.37 | 20.62 | 21.63 | 21.53 | 20.62 | 4.4% |
| Dec-12 | 30.03 | 52.37 | 30.03 | 38.37 | 31.66 | 30.03 | 4.7% | 20.65 | 52.37 | 20.65 | 21.66 | 21.56 | 20.65 | 6.0% |
| Jan-13 | 36.58 | 53.48 | 36.58 | 46.12 | 38.57 | 36.58 | 5.1% | 24.45 | 53.48 | 24.45 | 30.31 | 25.53 | 24.45 | 8.0% |
| Feb-13 | 36.59 | 53.48 | 36.59 | 46.12 | 38.57 | 36.59 | 4.5% | 24.45 | 53.48 | 24.45 | 30.31 | 25.53 | 24.45 | 4.4% |
| Mar-13 | 33.58 | 53.48 | 33.58 | 41.98 | 35.41 | 33.58 | 3.0% | 22.42 | 53.48 | 22.42 | 24.60 | 23.41 | 22.42 | 5.6% |
| Apr-13 | 33.56 | 53.48 | 33.56 | 41.95 | 35.38 | 33.56 | 1.4% | 22.44 | 53.48 | 22.44 | 24.63 | 23.44 | 22.44 | 6.6% |
| May-13 | 34.06 | 53.48 | 34.06 | 40.95 | 35.91 | 34.06 | 6.2% | 22.73 | 53.48 | 22.73 | 23.64 | 23.74 | 22.73 | 12.2% |

**Underlying Energy Cost ($MM)**

| | On-Peak Period Energy Cost ($MM) | | | | | | | Off-Peak Period Energy Cost ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up | Total | Swap | LT Renew | 2011 RFP | 2012 RFP | Spot | Gross-Up | Total |
| Jun-12 | 34.67 | 0.64 | 13.57 | 15.09 | (0.20) | 3.72 | 67.5 | 39.62 | 0.53 | 3.70 | 8.34 | 0.14 | 3.37 | 55.7 |
| Jul-12 | 34.67 | 0.50 | 24.30 | 19.98 | 0.12 | 4.58 | 84.1 | 42.10 | 0.48 | 7.97 | 12.20 | (0.02) | 4.94 | 67.7 |
| Aug-12 | 37.97 | 0.55 | 16.01 | 19.03 | (0.34) | 5.75 | 79.0 | 38.80 | 0.61 | 2.61 | 9.30 | (0.03) | 2.79 | 54.1 |
| Sep-12 | 31.37 | 0.55 | - | 7.71 | (0.11) | 1.87 | 41.4 | 42.93 | 0.49 | - | 2.96 | (0.13) | 2.20 | 48.4 |
| Oct-12 | 37.97 | 1.03 | - | 2.91 | (0.11) | 0.41 | 42.2 | 38.80 | 0.87 | - | - | (1.25) | 0.82 | 39.2 |
| Nov-12 | 34.67 | 1.12 | - | 3.72 | (0.25) | 0.59 | 39.8 | 39.62 | 1.01 | - | - | (0.38) | 0.71 | 41.0 |
| Dec-12 | 33.02 | 0.97 | - | 7.09 | 0.20 | 1.27 | 42.6 | 43.75 | 0.77 | - | 3.66 | (0.17) | 1.28 | 49.3 |
| Jan-13 | 37.09 | 1.32 | - | 10.18 | (0.02) | 1.84 | 50.4 | 41.31 | 1.08 | - | 4.00 | 0.11 | 1.92 | 48.4 |
| Feb-13 | 33.72 | 1.11 | - | 6.17 | 0.18 | 1.36 | 42.5 | 37.09 | 0.90 | - | 2.25 | (0.18) | 0.87 | 40.9 |
| Mar-13 | 35.41 | 1.23 | - | 2.38 | (0.23) | 0.78 | 39.6 | 42.99 | 1.11 | - | - | (0.82) | 1.03 | 44.3 |
| Apr-13 | 37.09 | 1.39 | - | - | (1.35) | 0.33 | 37.5 | 38.78 | 1.06 | - | - | (3.29) | 0.92 | 37.5 |
| May-13 | 37.09 | 1.40 | - | - | (1.68) | 1.45 | 38.3 | 41.31 | 0.93 | - | - | (3.88) | 1.78 | 40.1 |
| Total | 424.7 | 11.8 | 53.9 | 94.3 | (3.8) | 23.9 | 604.8 | 487.1 | 9.8 | 14.3 | 42.7 | (9.9) | 22.6 | 566.6 |
| Summer | | | | | | | 272.0 | | | | | | | 225.9 |
| Non-Summer | | | | | | | 332.8 | | | | | | | 340.7 |

**Total Underlying Energy Cost ($/MWh)**

| | |
|---|---|
| Summer Peak | 50.12 |
| Summer Off-Peak | 43.92 |
| Non-Summer Peak | 51.15 |
| Non-Summer Off-Peak | 53.11 |
| Total | 49.86 |

# Appendix C

**Calculations Related to the Historical ComEd Purchased Electricity Adjustment (PEA)**

Source: Commonwealth Edison Company Rider PE PEA

(data for earlier months from https://www.icc.illinois.gov/ormd/PEA.aspx, and data for later months from ComEd)

| Month | Purchased Electricity (PE) Procurement (MWH) | Rider PE Procurement Expenses Accrued ($) | Total Accrued Revenues ($) | Incremental Deferral ($) | Costs in Excess of Revenues ($/MWH) | PEA Charge/(Credit) ($/MWH) |
|---|---|---|---|---|---|---|
| Mar-12 | 2,189,226 | 188,246,673 | 159,700,309 | 28,546,364 | 13.04 | 5.00 |
| Apr-12 | 2,048,016 | 173,465,083 | 139,703,737 | 33,761,346 | 16.48 | 5.00 |
| May-12 | 2,467,141 | 195,780,017 | 166,137,994 | 29,642,023 | 12.01 | 5.00 |
| Jun-12 | 3,243,597 | 190,027,903 | 206,589,249 | (16,561,346) | (5.11) | 5.00 |
| Jul-12 | 4,209,569 | 248,258,486 | 279,786,687 | (31,528,201) | (7.49) | 5.00 |
| Aug-12 | 2,755,686 | 173,999,555 | 178,965,998 | (4,966,443) | (1.80) | 5.00 |
| Sep-12 | 1,828,383 | 127,097,460 | 128,557,994 | (1,460,534) | (0.80) | 5.00 |
| Oct-12 | 1,594,271 | 121,486,406 | 113,535,566 | 7,950,840 | 4.99 | 5.00 |
| Nov-12 | 1,600,759 | 116,068,135 | 125,985,680 | (9,917,545) | (6.20) | 5.00 |
| Dec-12 | 1,826,174 | 128,361,125 | 131,668,415 | (3,307,290) | (1.81) | 1.18 |
| Jan-13 | 1,905,910 | 132,236,756 | 138,032,700 | (5,795,944) | (3.04) | (0.94) |
| Feb-13 | 1,474,955 | 107,787,531 | 111,828,597 | (4,041,066) | (2.74) | 5.00 |
| Mar-13 | 1,201,517 | 98,391,023 | 90,338,901 | 8,052,122 | 6.70 | (5.00) |
| Apr-13 | 994,128 | 87,334,833 | 74,262,260 | 13,072,573 | 13.15 | (5.00) |
| May-13 | 1,024,461 | 94,299,174 | 77,934,623 | 16,364,551 | 15.97 | (5.00) |