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

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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

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[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:

- The IPA's analysis is based on an unsupported and untested assumption about FPFR product pricing. 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.

- 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. Such omissions or underestimations include:

    - The IPA's analysis underrepresents bundled service load 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 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.

    - 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 financial risks to customers under the block-and-spot approach which are included in the IPA's analysis.

    - 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. 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]

- 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 appears to omit the risk that the costs of any of the non-energy supply components vary from expectations.

- 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. 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.

- 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.

- The IPA does not appear to consider the most likely way that FPFR 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). 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:

- Purchased Electricity Prices ("PEP") – 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.

- Purchased Electricity Adjustment ("PEA") – 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.

- Deferred Cost Regulatory Asset – 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.

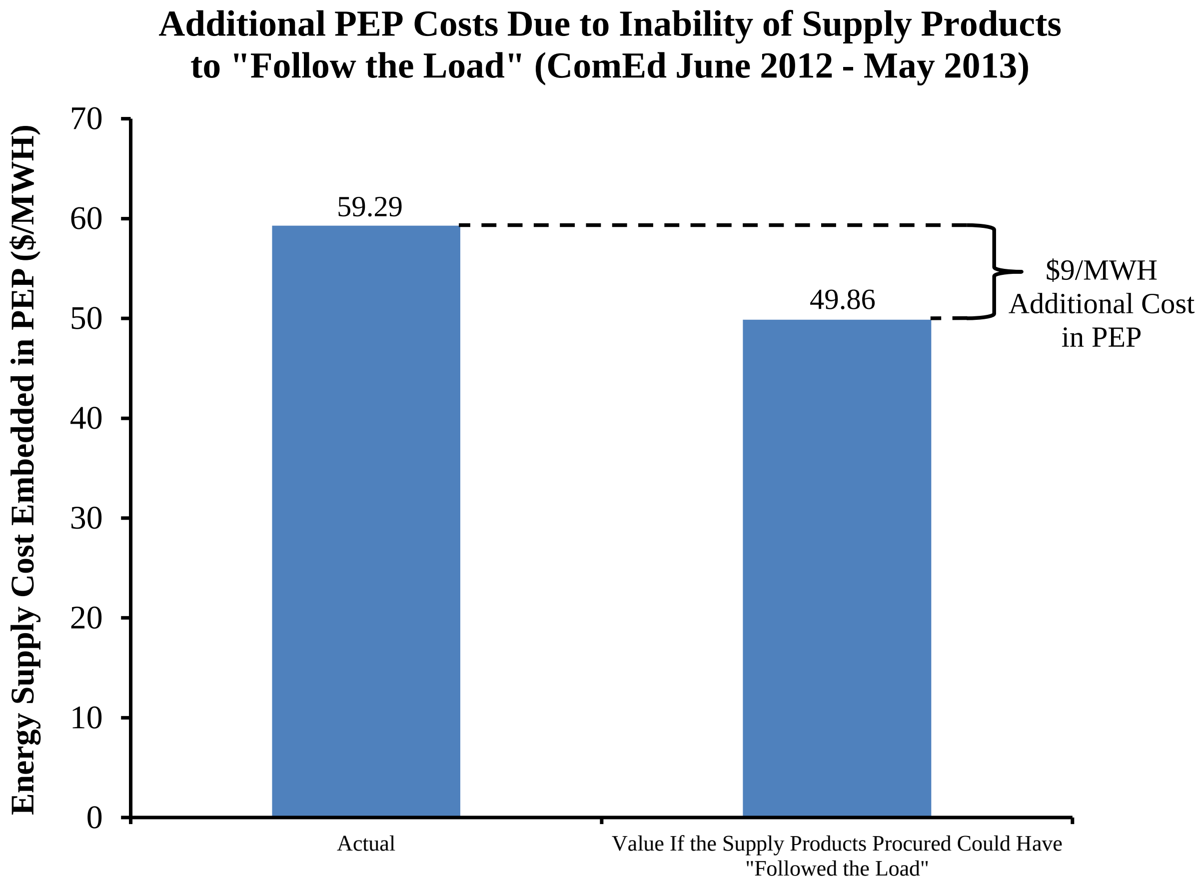
A straightforward analysis of these three components of Illinois' bundled service customers' rates shows that customers in Illinois have indeed been subject to costs and unnecessary adverse financial risks due to the block-and-spot approach's inability to match the quantities of fixed-price supply purchased 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.



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.

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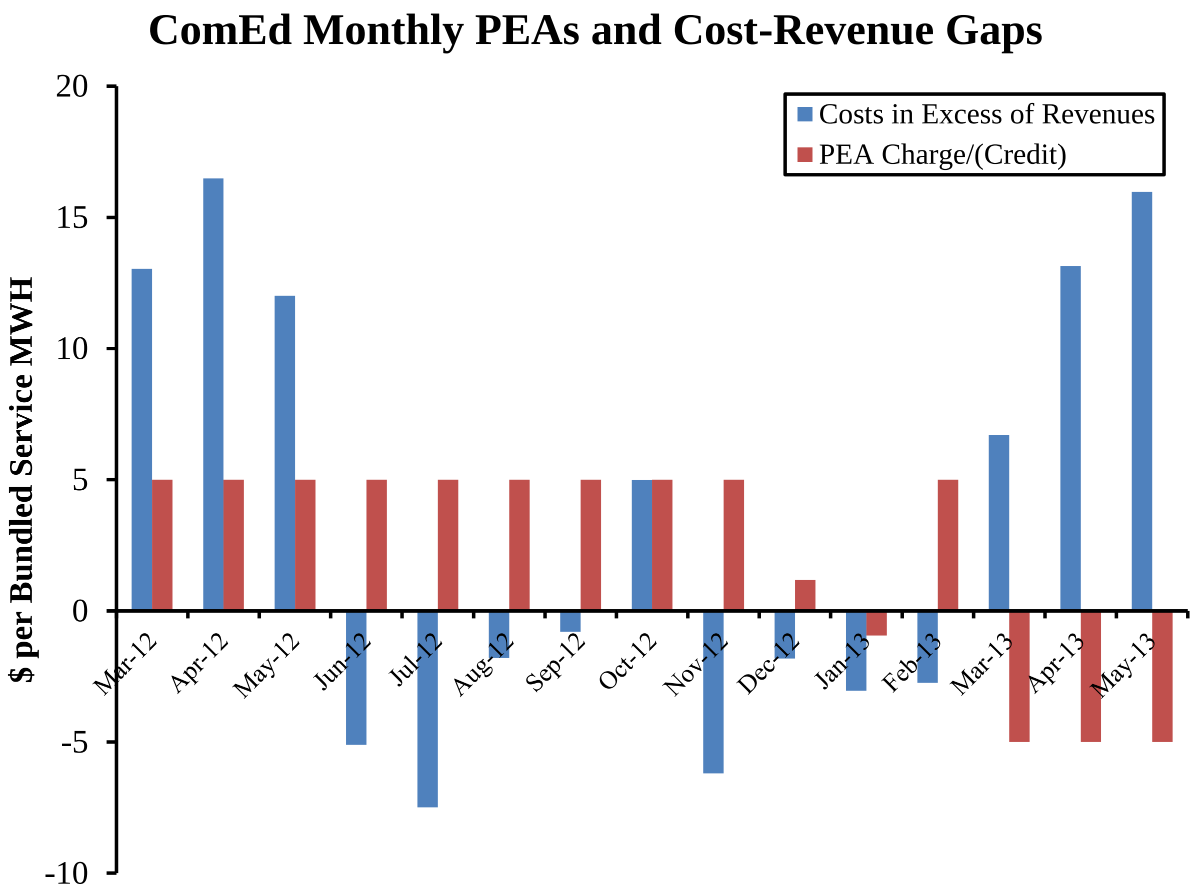
[15] Data from http://www.icc.illinois.gov/ormd/PEA.aspx. Some data is from reports that were not yet posted on this website, but which were made publicly available.

[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.

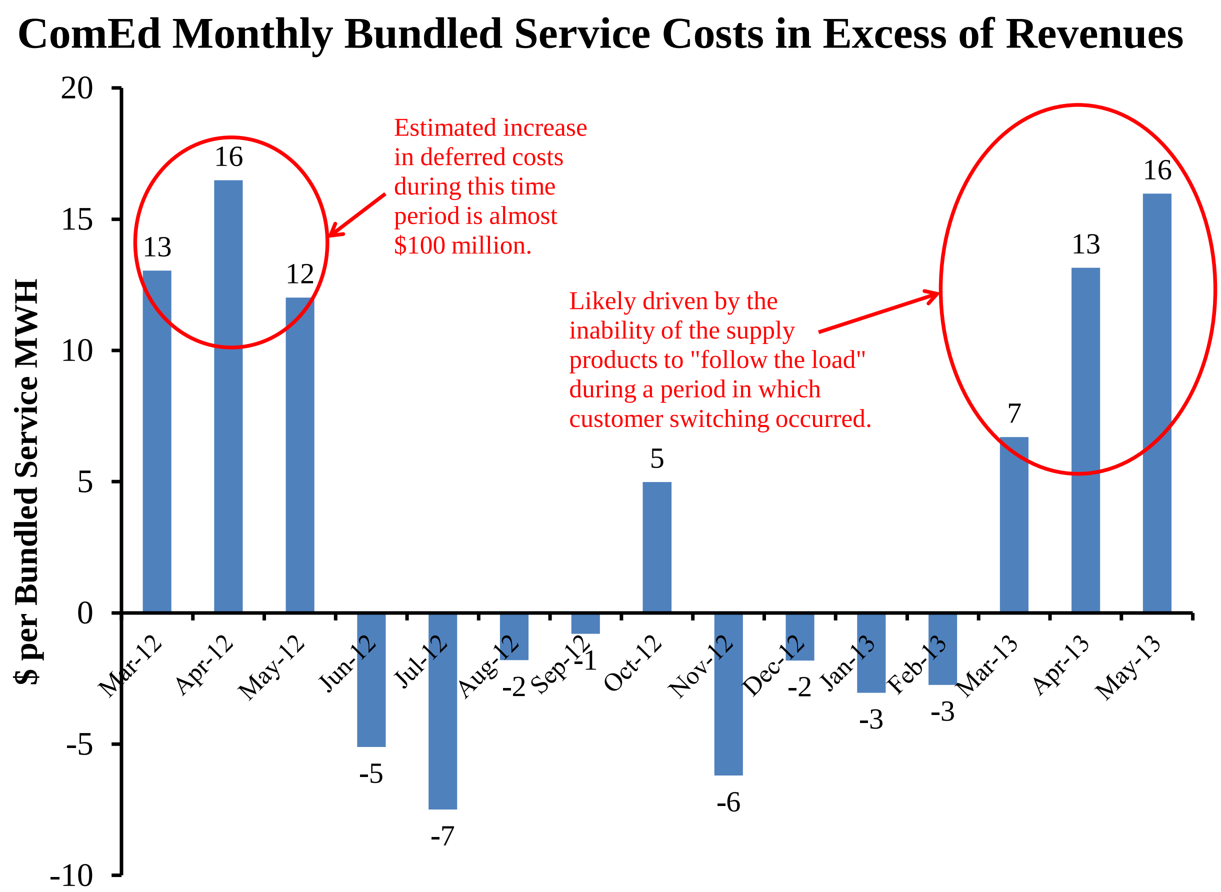


If the PEA were providing a reasonable signal of the underlying supply cost in a given month, then we would expect it to be at its maximum value of \$5/MWH when a revenue shortfall exists (in other words, it would be at its maximum to mitigate that shortfall as much as possible) and we would expect it 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

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[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

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[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

[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

[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.

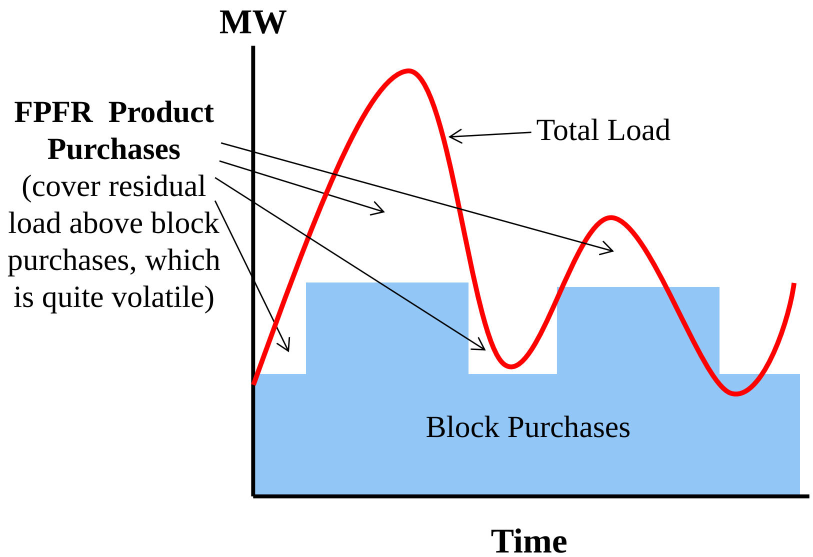
F. The IPA Does Not Appear to Consider the Most Likely Way That FPFR Products Would Be Defined and Integrated into the Existing Supply Portfolio

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.

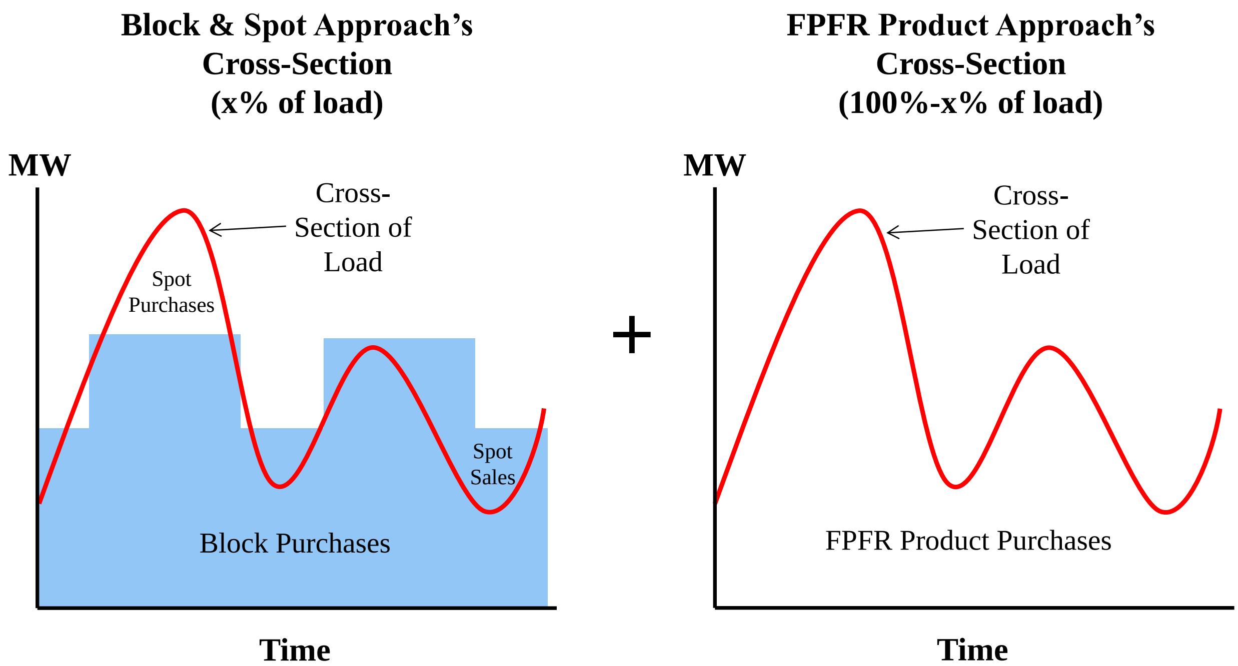


This approach would require the FPFR product suppliers to bear the entire load risk while only serving the residual load, and is unlike FPFR products in place in many other jurisdictions.[60] Not surprisingly, the IPA concludes that under these conditions the FPFR product prices could be high and that 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.

[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)