market participation by vendors does not yield sufficient additional value to consumers. The nature of the energy efficiency market is that in many cases efficiency is derived from single distribution channels. In the same way that having many supplier options (from bundled rate to residential real-time pricing to retail service) benefits consumers by offering a variety of energy services, there could be energy efficiency offerings that would benefit from multiple channels. While there do not appear to be such programs in this year's submittals, the IPA suggests using the term "competing" for such programs if they are proposed in future years. The general goal would be that duplicative programs are to be avoided, but that competing programs would be acceptable to the extent that the competition does not render one or both non-cost effective.

The second issue is the authority of the Commission to reject a third-party bidder's program that is "competing" with or "duplicative" of a utility's program but which otherwise passes the standard for cost-effectiveness. Section 16-111.5B does not directly address this matter, although it is possible to read the statutory terms "new," "expanded," and "incremental" as requiring new programs that are additive (*i.e.* non-competitive and non-duplicative) to utility programs. In the interests of administrative efficiency, minimzing market inefficiency, and promoting program quality, ~~T~~the Commission ~~may wish to~~should clarify ~~if~~ that the utilities ~~may~~ can and should screen out those programs pursuant to Section 16-111.5B(a)(3). ~~or whether the IPA must include all "competing" or "duplicative" programs and then request that the Commission remove those programs pursuant to Section 16-111.5B(a)(5).~~

The IPA sought comments on these issues and after reviewing those comments, going forward, the IPA recommends continuing the process followed this year ~~that does not set a specific standard~~. In this process each utility would continue to provide to the IPA all third-party bids received, and further the utility would provide an initial recommendation regarding any screening out of programs that the utility deems to be duplicative. The IPA would then include in its filing to the Commission its assessment of all bids received and its assessment of the screening (if any) done by the utility. The Commission would then provide the final determination as to which programs are included based on any objections received that would change the Commission's understanding of if the program in question is or is not duplicative or competing.

In general stakeholders felt that it was important for the Commission to have the opportunity to review information regarding all bids, and also that the utilities be given some level of discretion (although stakeholders did not agree on just how much) in judging which programs to include and which ones were duplicative and did not add value. The IPA recognizes that the marketplace for energy efficiency is dynamic and that TRC calculations are generally done in isolation (*i.e.* imagining that each program is not competing with the same or similar programs for market share). Including duplicative or competing programs could impact the accuracy of the TRC test.

If the Commission chooses to adopt a standard for duplicative or competing programs, the IPA suggests that the standard be a multi-factor inquiry rather than a "bright line" test. Factors that the IPA suggests that the Commission consider to be part of the standard include (but are not limited to): (1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); ~~and~~ (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record); (6) the effect(s) on utility joint program coordination; and (7) impact on Section 8-103 EEPS portfolio performance. If any one or more factors is a critical element of a third party proposal, the utility may then exclude the proposal from its 16-111.5B proposal to the IPA. The IPA invites parties in objections to recommend additional criteria or modify the criteria suggested above.

The IPA notes that in reviewing the RFPs issued by the utilities they do contain guidance to potential bidders regarding not proposing duplicative programs. Some stakeholders believe that this language may have been unclear or confusing. The IPA suggests that for future RFPs the utilities work with stakeholders to refine that language to make it clearer to potential bidders.

7.1.4 Ameren

Ameren's submission to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA is included in Appendix B of this Plan. The submission including its own seven appendices may be found on the IPA website posting of the 2014 Procurement Plan at www.illinois.gov/ipa. Two of the Appendices (6 and 7) in Ameren's submittal contain confidential data, and are redacted.

Ameren's proposal contains programs and measures that were "expanded" from the Section 8-103 by virtue of being removed from Ameren's Section 8-103 three year plan filing[99] and moved to and expanded in its IPA submission. Examples include moving specialty lighting, electric home improvements, small business incentives and multifamily common area measures out of their Section 8-103 portfolio and into the IPA submission at higher than previous levels.

In its submittal, Ameren also stated that, "[T]his submission represents one year of savings and costs. However, AIC reserves the right to submit multiple years of programs and related savings in future submissions."[100] One impact of this approach is that the MWh goal of the submittal is smaller than that of the previous year, in part for the simple reason that it includes only stand alone programs rather than last year's the expansion of programs authorized pursuant to Section 8-103. The lack of Section 8-103 programs to expand illustrates the open issue raised above about years in which a three-year energy efficiency plan is under consideration.

Ameren's assessment includes five energy efficiency offerings in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[101] These programs are exhibited in Table 7-1,

Table 7-1 Ameren Energy Efficiency Offerings

Program	Net Savings (MWh)	Total Utility Cost	TRC
Multifamily	14,247	$4,292,956	2.95
Specialty Lighting	5,970	$2,794,093	1.12
Rural Efficiency Kits	3,555	$377,365	3.28
All-Electric Homes	11,189	$7,039,702	1.49
Small Business Direct Install	30,719	$8,715,840	1.14

The total net savings for these programs is estimated as 65,680 MWh at the busbar.[102] The programs also contribute to a peak reduction of approximately 2 MW. The estimated savings attributable to eligible retail customers is 17,950 MWh. The IPA believes that subject to the modifications and open issues discussed below, Ameren's submission meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix B should be approved pursuant to Section 16-111.5B(a)(5).

In addition to its own programs ("Ameren programs") Ameren assessed six additional programs from third party vendors ("Bidder programs"). Three Bidder programs did not pass the TRC; one program was determined by Ameren to be duplicative of the existing SAIC Small Business Direct Install program, one program was excluded because it was designed as a gas and electric savings program that assumed participation by a separate gas utility that could not be assumed, and another program was the expansion of the SAIC Small Business Direct Install program.

[99] See ICC Docket No. 13-0498.
[100] Appendix B, Energy Efficiency Submittal at 4.
[101] Ameren also provided the results of the UCT test and one program did not pass the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.
[102] Note that in Ameren's submittal document net savings are primarily listed as at the meter. For consistency net savings in this plan are listed at the busbar.

7.1.4.1 Ameren Duplicative Program

The IPA has reviewed the Bidder program that Ameren considered duplicative of SAIC Small Business Direct Install program and it illustrates the challenges of the "competing" and "duplicative" issue highlighted in Section 7.1.3.3~~7.1.3.37.1.3.4~~. The Bidder program would specifically target class B and C commercial office spaces, which is a smaller market subset of the SAIC Small Business Direct Install program. Class B and C office spaces are already served by Ameren's program (but not specifically targeted), so failure to include the Bidder program would not hinder the statutory mandate to expand cost effective energy efficiency programs. On the other hand, there could be value in testing alternative delivery mechanisms for this specific sector if, in fact, the Bidder program is superior (although there is not sufficient information in the submittal to determine that). Absent any determination that this program in fact is not duplicative (albeit more targeted) of what Ameren will already offer in the SAIC Small Business Direct Install program, the IPA recommends that the Commission not approve the inclusion of this program as its inclusion may not be "practicable."

7.1.4.2 Ameren Student Energy Kits

Ameren also proposed excluding a Bidder program that would deliver education kits to students via the classroom. Ameren stated that it did not include the program because it is a gas and electric savings program and Section 16-111.5B specifies that the IPA energy efficiency programs be provided and coordinated by the electric utilities for the purposes of electric savings. Ameren further noted that the program targeted an area where Ameren was not the gas utility, that the gas utility in question (Nicor Gas) is not a participant in this procurement process and that their participation cannot be ensured or required. In comments Ameren further stated that they did not evaluate or validate this vendor in terms of its ability to actually deliver the program, its reputation, credit worthiness or references once it was determined that the program was not applicable to this procurement process. Therefore, in the event the program is conditionally approved, the program's inclusion should also be subject to Ameren's evaluation and validation of the vendor.

Ameren's August 31, 2013 Section 8-103 filing (which, unlike Section 16-111.5B, addresses both gas and electric energy efficiency because Ameren is a combination utility) included a proposed student energy kit program by a different vendor and at a substantially larger scale. While the IPA has not conducted a thorough comparison of the details of the two programs, the presence of that proposed program suggests that this market sector may be well served. Notwithstanding the contractual issues identified, assuming that the Section 8-103 program is approved by the Commission, the IPA does not recommend the inclusion of the student energy kit program under Section 16-111.5B.

7.1.4.3 Ameren's Expansion of Small Business Direct Install Program

Ameren included in their submission a base program for small business direct install. They also included in their assessment the bid for an expanded version of the program (73,435 MWh versus 30,719 MWh) but recommended the base level – a continuation of the same size of program from the previous year (which began implementation in June, 2013) – because in Ameren's view it is, "prudent and responsible to first assess and evaluate the performance of this program prior implementing it again on a larger scale."[103] The IPA appreciates the program management and evaluation issue that Ameren raises, but notes that programs implemented under Section 16-111.5B do not have penalties for non-performance. In comments, Ameren also raised the issue of risks associated with the ICC reconciliation review, which examines Ameren's management of the program. The IPA understands and appreciates that utilities are always subject to the review of certain management and performance standards by the ICC, and that placing unrealistic expectations on any utility program could theoretically force imprudent steps that could jeopardize cost recovery. However, the IPA would like to see more discussion from Ameren as to why an expansion of the program to a level first raised by Ameren, or its vendor, would lead to that result.

7.1.4.4 Ameren Requested Determinations

Ameren also requested in their filing that the ICC make several determinations:

[103] Appendix B, Energy Efficiency Submittal at 12.

- "[I]t is realistic to assume that actual market results will differ from anticipated results. Therefore AIC formally requests approval for an indeterminate fluctuation in savings that may occur by program year end."[104]

- Ameren, "seeks confirmation that AIC is permitted to recover costs that incidentally (3 - 5%) exceed the estimated program costs as consistent with the Commission finding in the ComEd energy efficiency 'Plan 2' plan docket #10-0570."[105]. This was a consensus item from the workshop. Ameren further notes that, "In lieu of this express approval AIC will be forced to prematurely discontinue approved programs prior to the budget cap being expended."

- "AIC notes that the savings estimates were determined using the current Illinois TRM and NTG values and unless these values are fixed, they are subject to change. With this submission, AIC is formally requesting that these values are fixed for implementation and evaluation for the determination of achieved savings."[106]

The IPA does not object to any of these requests, as they appear to be consistent with consensus items from the workshops.

Besides these determinations, the IPA requests that the ICC at minimum approve the incremental energy efficiency programs proposed by Ameren and that the ICC further consider the additional recommendations of the IPA as set forth herein.

7.1.5 ComEd

ComEd's submission to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA is included in Appendix C of this Plan which may be found on the IPA's website posting of the 2014 Procurement Plan at www.illinois.gov/ipa. Note that the document entitled "ComEd 2013 Third Party Efficiency Program Summary of Vendor Scoring Process, July 5, 2013" contains confidential data and is redacted from this Plan.

ComEd's assessment includes eight energy efficiency offerings in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[107] These programs are exhibited in Table 7-2.

Table 7-2 ComEd Energy Efficiency Offerings

Program	Net Savings (MWh)			Three Year Program Cost	TRC
	Program Year 1	Program Year 2	Program Year 3		
Home Energy Reports	301,780	374,971	390,233	$41,552,668	1.90
Small Business Energy Services	111,020	147,657	185,403	$110,013,985	2.32
CUB Energy Saver	6,628	13,256	19,884	$1,775,000	1.72
Home Energy Services	2,239	2,239	2,239	$4,701,285	1.23
Small Commercial Power Strip	4,840	-	-	$1,267,000	1.05
Energy Stewards	1,366	-	-	$200,000	1.97
Small Commercial HVAC Tune-up	3,690	10,335	12,170	$6,841,506	1.78

[104] *Id.* at 8.
[105] *Id.* at 8.
[106] *Id* at 11; *see also id.* at 14 (similar language).
[107] ComEd also provided the results of the UCT test and one program did not pass the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Retrofit Chicago Residential	1,285	1,685	2,029	$1,667,667	1.18

ComEd proposed both multi-year and single-year programs. The net savings at the busbar are 432,848 MWh for the first program year, 550,143 MWh in the second program year and 611,958 MWh in the third program year. These programs will deliver 16 MW of reduction in peak procurement for the 2014-2015 program year. The savings attributable to eligible retail customers is 88,839 MWh in the first program year, 137,288 MWh in second program year, and 184,078 MWh in the third program year. The IPA believes that subject to the proposed modifications and resolution of the open issues discussed below ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C should be approved pursuant to Section 16-111.5B(a)(5).

As with Ameren, ComEd's proposal contains programs that it determined fit best in the Section 16-111.5B model but which had previously been part of EEPS. For ComEd these programs are the Home Energy Report and the Small Business Energy Services. And as with Ameren, these programs are included at scales larger than had been implemented under EEPS and are therefore considered program expansions.

ComEd evaluated 17 third party bids. A summary of the bids is included in Appendix C-4. ComEd included six of them (Bid numbers R1, R2, R4, M1, B1, and B3) in its submission to the IPA.[108] Of the eleven Bidder programs that were not included, one program was withdrawn by the bidder (B2), three programs were determined to be incomplete or unresponsive (M3, B4, and B8), one did not pass the TRC (R3), and six were deemed by ComEd to be duplicative of other proposals that ComEd considered. Of the six Bidder programs that ComEd considered duplicative, one was duplicative of ComEd's current multifamily program, two were duplicative of other current ComEd energy efficiency programs, and three were duplicative of the Small Business Energy Services that ComEd is including in its Section 16-111.5B proposal. The duplicative multifamily program (M2) also failed the TRC test.

As noted above, the Commission has not provided a standard pursuant to Section 16-111.5B for evaluating "competing" or "duplicative," and has not provided direction about how to deal with "competing" or "duplicative" programs. The IPA therefore provides the following discussion and recommendations on how to address each specific program.

7.1.5.1 ComEd Duplicative Programs (Current Portfolio)

For the two Bidder programs (B9 and B10) that compete with existing ComEd Section 8-103 programs the IPA notes that ComEd describes them as "substantially identical" to the existing programs. However, the ComEd Commission-approved programs are part of the Section 8-103 3-year plan portfolio that is ending this year and will be up for renewal concurrently with the Procurement Plan approval docket. ComEd has subsequently proposed programs in its August 31, 2013 Section 8-103 filing[109] which in substance appear to continue those existing programs. . The IPA recognizes that there is a risk of the programs not being approved in the Section 8-103 proceeding, and also that Section 8-103 programs are subject to savings goals that lead to penalties if not met. As a compromise approach the IPA recommends that the Commission consider conditional approval of the two programs. If the Commission subsequently does not approve the competing programs in its Section 8-103 plan then these programs (B9 and/or B10) should proceed. On the other hand if the Section 8-103 programs are approved by the Commission then this conditional approval should be rescinded. Because it appears that these programs have been put forward for approval in ComEd's Section 8-103 proceeding, the IPA recommends that this conditional approval should not be reflected in the load forecast included in this Plan. By the time of the proposed March load forecast update, this issue should be resolved and the load forecasts could be updated as needed.

[108] For more information on the included bids, see Appendices C-3 and C-4.
[109] See ICC Docket No. 13-0495.

7.1.5.2 ComEd Duplicative Programs (Small Business Energy Services)

A different issue arises for the three Bidder programs that ComEd excluded that are duplicative of the Small Business Energy Services program that ComEd included in its Section 16-111.5B filing. One of the Bidder programs (B7) appears to have a scope as wide as the Small Business Energy Services Program in terms of customers, but has a significant geographical limitation. The IPA does not see a compelling reason to include this program and defers to ComEd's determination to include its core Small Business Energy Services program to serve that sector. The other two programs appear to target specific business sectors and as suggested with the similar Ameren submittal, the Commission may only want to consider including them if it is determined that they are not truly duplicative.

7.1.5.3 ComEd Requested Determination

ComEd has requested that, "[t]o the extent that the IPA and the ICC approve procurement of the programs ComEd requests that the approval be for all three years."[110] In light of the consensus item that multi-year programs should be approved through the Section 16-111.5B process and because the programs' TRC calculations are greater than one for a multi-year timeframe, The IPA agrees with that request.

Besides this determination, the IPA requests that the ICC at minimum approve the incremental energy efficiency programs proposed by ComEd and that the ICC further considers the additional recommendations of the IPA.

7.1.6 Energy Efficiency as Supply Resource

The IPA requested feedback from stakeholders on the concept of using energy efficiency as a supply resource that could reduce the need for procurement. The most detailed feedback received was that submitted by CUB. CUB proposed several possible program structures including ones to address high load hours, high price hours and peak hours. The IPA appreciates these suggestions and is most intrigued by the high load model. While the other two may have significant potential value to consumers, the high load model would appear to be the model that would most likely fit into the procurement processes that the IPA can, and does, conduct. The model also appears to be similar to an existing program in ISO New England that could provide a starting point for consideration.

ComEd and Ameren recommended removal of this section from the plan because it did not propose a specific procurement for 2014. The IPA agrees that because it is not proposing such a procurement in the 2014 Procurement Plan, the IPA will not add additional specifics at this time. Instead, the IPA proposes to conduct workshops and receive stakeholder input in early 2014 to further explore this model for the possible inclusion of a more specific proposal in future procurement plans.

The AG, NRDC, and the Sierra Club all commented on the underlying discussion, including the contention that the current Section 16-111.5B process does not sufficiently incentivize peak load reduction. The IPA appreciates these comments, and will take these comments into account in developing a proposal for the workshop process.

7.2 Procurement Strategy

The selection of the Agency's procurement strategy is driven by the following challenges:

- Price hedging: the Agency ought to find the best compromise between hedging against adverse price movements and retaining the flexibility to respond to rapidly changing market conditions
- Load hedging: the accuracy of load forecasts increases as time to delivery decreases particularly with regard to switching risk. For instance, load forecasts for the delivery year 2014-2015 that the utilities will submit in March 2014 should be more accurate than the forecasts for that year

[110] Appendix C at 26.

submitted in July 2013. Therefore, the Agency ought to ensure it has the opportunity to adjust its supply strategy to account for changes in load forecasts

- Control of overhead cost: RFPs for energy contracts are costly and the Agency ought to take this into account in its procurement strategy.

In order to address these challenges, the Agency's procurement strategy has historically been designed in a "laddered" fashion: a large fraction of the load would be purchased for the prompt (upcoming) delivery year while smaller fractions of the load would be purchased for the subsequent two years. Prior to the 2013 Procurement Plan, the IPA procurement strategy for energy products was designed to result in a ladder of products predicated on being 100% hedged for the prompt year, 70% hedged for the second year, and 35% hedged for the third year.

The laddered strategy is used to mitigate price risk, smooth out price spikes, and minimize exposure to any single set of forward prices. Due to accelerated customer switching, and, to a lesser extent, to declining market prices, the IPA considered a revised strategy in the 2013 Procurement Plan in that 75% of the load would be hedged for the prompt year, 50% for the second year and 25% for the third year. By reducing the total hedge, the utilities partly reduced their exposure to load loss, while the generally stable or declining market price environment reduced the penalty for underhedging. Ultimately the IPA recommended this revised strategy be deferred until future Plans and the ICC agreed.

The analyses in Chapter 6 indicated that, under the assumptions of that chapter, while hedging could reduce the impact of forward price uncertainty it could not counter the effect of load uncertainty, a somewhat more significant impact (Section 6.5.2). The following are conclusions relevant to procurement strategy that may be drawn:

- Load reduction is a particularly significant risk because losses associated with currently out-of-market hedges will have to be spread over a smaller pool of kWh. The utilities' load forecasts, summarized in Sections 3.2 and 3.3, did not assess the probabilities of their high and low load scenarios. Ameren's high and low scenarios each had the same weight in the Monte Carlo model used for Chapter 6, and ComEd's high and low scenarios each had the same weight (although it was different from the weight on each of the Ameren high and low scenarios). Given the high current levels of municipal aggregation, it seems more likely that there will be a "rebound" effect reversing switching in the coming years. This effect was observed in Ohio, followed by a re-reversal (Figure 6-10).

- Switching decisions, especially having to do with municipal aggregation, have effects lasting two to three years. This distinguishes switching-related load variation from price variations, which decay much more quickly. It makes sense to delay forward purchases to the extent that they create load risk. The uncertainty in load forecasts should be reassessed each year. For example, in previous years a 100%/70%/35% procurement strategy seemed reasonable. In 2013 it was considered that the potential for load reduction made that strategy too risky and that forward purchases should be delayed with a 75%/50%/25% strategy. However, no formal request was made of the ICC in this regard given that no procurements were required in that plan.

- On the other hand, if the volume of load that could return to utility service is now greater than the risk of additional switching away, and if upside price risk is greater than downside risk, then the situation of the last couple of years could reverse and it would make more sense to be fully hedged close to the delivery month. In fact, the impact of shaping, as noted in Chapter 6, can be mitigated by hedging at about 106% of average load June through October and 100% of average load November through May, so that "fully hedged" should be interpreted as 106% of average load June through October and 100% of average load November through May. Being fully hedged close to the delivery month will also help to reduce the volatility of PEA.

- Forward contracts do not necessarily provide perfect hedges against load uncertainty; however, other products, such as full requirements hedges, are available in the market at premium prices.

7.2.1 Standard Market Products

The IPA recommends that the basic strategy discussed in the 2013 Procurement Plan be slightly modified. The procurement goal for a mid-April 2014 procurement event is to hedge 106% of the expected load forecast for June-October 2014 and 75% for November 2014 – May 2015. The Agency recommends that the utilities update their load forecasts in March 2014 subject to the consensus of the utilities, IPA, ICC Staff, Procurement Administrator(s) and Procurement Monitor, the recommendations in Table 7-4 through Table 7-11 be recomputed and further include and any Commission-approved energy efficiency programs and the impact of any partial curtailment of long term renewable contracts.

The March 2014 forecasts should include the effect of approved energy efficiency programs and provide the expected case as well as the high and low scenarios. Absent any large reduction in the Required Purchase Amounts, a procurement event should be held in April, 2014 for each utility to acquire contracts: for Ameren in the Required Purchase Amounts of Table 7-4, Table 7-6, and Table 7-7 and for ComEd in the Required Purchase Amounts of Table 7-8, Table 7-10, and Table 7-11.

The Agency also seeks approval for conducting a procurement event in September 2014 to bring the hedge levels to 100% for the period November 2014 to May 2015. However, the Agency further recommends that, after taking into account the utilities' July 2014 forecasts, which the Agency recommends be expanded to include the November 2014 to May 2015 period, it be given the authority, in consultation with ICC Staff, ComEd, the procurement administrator, and the procurement monitor, to forego the September procurement if consensus is reached that the procurement would not be cost effective. Factors that the IPA proposes to consider in making such a determination would include if the utilities' forecasted loads drop significantly, the risk associated with keeping the open position compared to the cost of running the auction, and the scale of the supplier fees required to recover the cost of the procurement. (This forecast for the November 2014 to May 2015 produced by the utilities in July 2014 will have no impact on the partial curtailment of long term renewable contracts which would have occurred prior to the 2014-2015 plan year and will be based on March 2014 forecast). The second procurement should be scheduled such that the ICC has time to approve any new procurement no later than September 22, 2014 in order to allow for prices for the non-summer period to be reset before the period begins.

Table 7-3 Summary of Hedging Strategy

Mid-April 2014 Procurement			Mid-Sept. 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**November 2014-May 2015**
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

If there is a rebound effect from municipal aggregation, the utilities may actually experience a switch of the load back to them in the near future upon contract expiration, (the schedule of expirations is shown in Figure 3-20). Because of this uncertainty, a bifurcated (April/September), fully hedged strategy in the 2014-2015 delivery year is a prudent option.

For the 2014 Procurement Plan, the Agency recommends purchases of standard forward block hedges in multiples of 25MW, as opposed to 50MW as in the previous plan, for the following reasons:

- The smaller individual increment provides a greater ability to accurately match load (25MW increments vs. 50MW increments), and therefore limits reliance on the spot market as a balancing mechanisms during hours of imbalanced supply.

- Liquidity appears adequate, given that index publishers such as Platt's survey transactions down to 25 MW.[111]
- They are standardized products with published definitions.
- Suppliers can hedge their own exposure in futures and/or forward markets.

7.2.2 Other Products

The IPA considered other products that provide hedges against load uncertainty, namely full requirements products and options.

The analysis in Chapter 6 indicates that full requirements products do not have a great cost or risk advantage over a block-based strategy. The analysis in Section 6.7 depends on a theoretical or conceptual model of how suppliers would price full requirements products. Prices may be less than the model implies, but on the other hand they may be much greater given the current load uncertainty discussed above.

The IPA is not prepared to recommend the use of full requirements products. The IPA is not aware of any recent assessments of the risk tolerance of retail customers; that is, their willingness to pay the utility for price insurance. Customers can easily switch to a competitive supplier and take fixed price service if they perceive value of mitigating price risk.

The IPA, in the preparation of this Procurement Plan, also considered a pilot program, involving only a fraction of the utilities' load, but decided that the overhead cost of designing a price benchmark and a procurement mechanism for such a different product is not justified given that hedging using standard block products represent a less expensive alternative. A successful pilot program must also provide meaningful results that can be assessed and provide input into future decisions. It was not clear to the IPA how such a pilot program in this Plan could provide those types of results in time for meaningful decisions that could inform future procurement plans.

Chapter 6 included a description of option products (Section 6.2.1). A call option could be used to hedge against future energy price increases if more load switches back to the utilities than forecasted. A put option could be used to hedge against energy price decreases if additional load switches from the utility; load loss due to additional switching compounds the financial risk of out-or-market hedges. The Agency did not conduct a full analysis of the economic and regulatory implications of including options in the 2014 Procurement Plan; however, the IPA plans to investigate those implications in developing its 2015 Procurement Plan.

7.2.3 Portfolio Rebalancing

Section 16-111.5(b)(4)(ii) requires that a procurement plan include "the criteria for portfolio re-balancing in the event of significant shifts in load." Historically, the IPA has used the utilities' updated March forecasts as the criteria for determining whether to re-balance a utility's portfolio. In particular, in last year's plan, the IPA focused specifically on the impacts to the forecast resulting from municipal aggregation in determining the need for re-balancing the portfolio.[112] Once again, the IPA proposes to use the utilities' updated March 2014 forecasts for the purposes of determining whether to re-balance the portfolio, assuming consensus is reached among the utilities, the IPA, ICC Staff, the Procurement Administrator, and the Procurement Monitor Otherwise, the July 2013 forecast will form the basis of curtailment. Also, once again, municipal aggregation will be the primary criteria for making that determination. As discussed in Section 3.3.3 above, numerous supply contracts for municipal aggregation will be expiring in the 2014 Planning Year. The utilities should survey all such municipalities and on the basis of those surveys update their March 2014 forecasts accordingly.

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[111] "Standard-size packages are multiples of 25 MW": Platts, *Methodology and Specifications Guide: North American Energy,* at http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_power_method.pdf, p. 4.
[112] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 67-69, 109-10.

In the 2013 Plan, the IPA noted that Ameren was substantially over-hedged and considered the benefits and drawbacks of holding the long position and allowing the hedges to settle in the MISO day-ahead market (as opposed to organizing a reverse RFP). The IPA believes that the risk of holding a long position could be mitigated by selling excess supply in the forward market in mid-September 2014. This belief is supported by the quantitative analysis in Section 6.6.2. However, in practice, the expected cost of holding the reverse RFP and the expectation that bidders would bid to buy the excess supply at or below the bid mark, could reduce the estimated benefit and produce a real financial loss that is perhaps equal or greater than the estimated avoided risk of holding the long position (about $0.30/MWh, plus $0.06/MWh in avoided expected cost). Additionally, the IPA notes that the excess supply in the Ameren portfolio is comprised of supply acquired as the result of mandated rate stability procurement; it is unclear whether selling such supply back to the market is permissible or prudent. The IPA, for these reasons, and for this Plan, does not recommend that Ameren rebalance its portfolio in an organized reverse auction and therefore recommends the position settle within MISO at the prevailing LMP

7.3 Quantities and Types of Products to be Purchased

7.3.1 Ameren

7.3.1.1 Ameren Procurement Delivery Years 2014 - 2017

Table 7-4 Ameren Procurement, Delivery Year 2014-2015, (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		106% (June-Oc.) or 75% (Nov-May) of Expected Load MW		Current Contracted Supply (MW)		Required Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-14	734	551	778	584	692	696	75	0
July-14	802	696	850	738	676	687	175	50
August-14	777	660	823	700	680	694	150	0
September-14	567	504	601	535	689	696	0	0
October-14	488	409	517	434	716	729	0	0
November-14	541	490	406	367	736	732	0	0
December-14	632	589	474	442	715	717	0	0
January-15	662	632	496	474	726	726	0	0
February-15	624	609	468	457	717	723	0	0
March-15	508	472	381	354	723	739	0	0
April-15	444	408	333	306	733	741	0	0
May-15	449	412	337	309	717	718	0	0

Table 7-5 Ameren Procurement, Nov.-May of Delivery Year 2014-2015, (To Be Conducted Mid-Sept. 2014 Based on the July 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)*		Required Mid-Sept. 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-14	541	490	541	490	736	732	0	0
December-14	632	589	632	589	715	717	0	0

January-15	662	632	662	632	726	726	0	0
February-15	624	609	624	609	717	723	0	0
March-15	508	472	508	472	723	739	0	0
April-15	444	408	444	408	733	741	0	0
May-15	449	412	449	412	717	718	0	0

*Including any purchases made in mid-April

Table 7-6 Ameren Procurement, Delivery Year +1 (2015-2016), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	633	517	317	258	236	245	75	25
July-15	744	612	372	306	223	235	150	75
August-15	712	600	356	300	227	240	125	50
September-15	509	470	254	235	235	242	25	0
October-15	438	389	219	195	262	269	0	0
November-15	494	456	247	228	275	278	0	0
December-15	575	558	287	279	259	261	25	25
January-16	614	595	307	298	273	267	25	25
February-16	600	574	300	287	258	266	50	25
March-16	469	454	235	227	264	284	0	0
April-16	418	392	209	196	279	279	0	0
May-16	424	395	212	198	259	265	0	0

Table 7-7 Ameren Procurement, Delivery Year + 2 (2016-2017), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	568	530	142	132	27	34	125	100
July-16	708	603	177	151	20	24	150	125
August-16	679	565	170	141	18	33	150	100
September-16	503	434	126	108	27	32	100	75
October-16	404	384	101	96	50	50	50	50
November-16	467	436	117	109	54	62	75	50
December-16	549	531	137	133	47	44	100	100
January-17	585	567	146	142	52	52	100	100
February-17	576	529	144	132	46	50	100	75
March-17	465	424	116	106	48	64	75	50
April-17	404	369	101	92	63	57	50	25
May-17	424	354	106	89	42	51	75	50

7.3.1.2 Delivery Year + 3 and Delivery Year + 4 (2017-2018 and 2018-2019)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan.

7.3.2 ComEd

7.3.2.1 ComEd Procurement Delivery Years 2014 – 2017

Table 7-8 ComEd Procurement, Delivery Year 2014-2015, (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		106% (June-Oct) or 75% (Nov-May) of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-14	1,570	1,238	1,664	1,312	676	535	1,000	775
July-14	1,851	1,442	1,962	1,529	797	617	1,175	900
August-14	1,732	1,361	1,836	1,443	703	581	1,125	850
September-14	1,363	1,072	1,445	1,136	520	534	925	600
October-14	1,184	945	1,255	1,002	571	595	675	400
November-14	1,282	1,070	962	803	608	601	350	200
December-14	1,477	1,249	1,108	937	669	572	450	375
January-15	1,474	1,260	1,106	945	688	589	425	350
February-15	1,377	1,172	1,033	879	622	584	400	300
March-15	1,229	1,035	922	776	583	612	350	175
April-15	1,104	909	828	682	601	615	225	75
May-15	1,135	928	851	696	616	575	225	125

Table 7-9 ComEd Procurement, Nov-May of Delivery Year 2014-2015, (To Be Conducted Mid-Sept 2014 Based on the July 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)*		Required Mid-Sept 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-14	1,282	1,070	1,282	1,070	958	801	325	275
December-14	1,477	1,249	1,477	1,249	1,119	947	350	300
January-15	1,474	1,260	1,474	1,260	1,113	939	350	325
February-15	1,377	1,172	1,377	1,172	1,022	884	350	300
March-15	1,229	1,035	1,229	1,035	933	787	300	250
April-15	1,104	909	1,104	909	826	690	275	225
May-15	1,135	928	1,135	928	841	700	300	225

*Including any purchases made in mid-April

Table 7-10 ComEd Procurement, Delivery Year +1 (2015-2016), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	1,477	1,165	739	583	526	536	200	50
July-15	1,749	1,362	875	681	498	517	375	175
August-15	1,639	1,297	820	649	504	532	325	125
September-15	1,286	1,013	643	507	521	535	125	0
October-15	1,113	895	557	448	572	596	0	0
November-15	1,218	1,015	609	508	610	603	0	0
December-15	1,408	1,187	704	594	570	574	125	25
January-16	1,406	1,200	703	600	590	591	125	0
February-16	1,323	1,120	662	560	574	586	100	0
March-16	1,181	994	591	497	585	614	0	0
April-16	1,057	875	529	438	603	617	0	0
May-16	1,103	893	552	447	617	577	0	0

Table 7-11 ComEd Procurement, Delivery Year + 2 (2016-2017), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load MW		25% of Expected Load MW		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Pea k	Peak	Off-Peak
June-16	1,451	1,126	363	282	525	534	0	0
July-16	1,723	1,357	431	339	497	516	0	0
August-16	1,630	1,258	408	315	502	530	0	0
September-16	1,259	1,006	315	252	519	533	0	0
October-16	1,098	883	275	221	569	593	0	0
November-16	1,214	1,007	304	252	606	599	0	0
December-16	1,405	1,185	351	296	567	570	0	0
January-17	1,407	1,200	352	300	586	587	0	0
February-17	1,316	1,119	329	280	570	582	0	0
March-17	1,178	993	295	248	582	610	0	0
April-17	1,054	870	264	218	599	612	0	0
May-17	1,107	888	277	222	613	574	0	0

7.3.2.2 Delivery Year + 3 and Delivery Year + 4 (2017-2018 and 2018-2019)

Given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for these years in this Procurement Plan.

7.4 Ancillary Services, Transmission Service and Capacity Purchases

7.4.1 Ancillary Services and Transmission Service

Both Ameren and ComEd have been purchasing their ancillary services and transmission services from their respective RTOs, MISO and PJM. The utilities have also been managing their FTRs and ARRs in their respective RTOs consistent with ICC orders in prior Plans. The IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged.

7.4.2 Capacity Purchases

The IPA concludes that it does not need to include any extraordinary measures in the 2014 Procurement Plan to assure reliability over the planning horizon.

The IPA recommends that ComEd continue to meet all of its capacity obligations through the PJM capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules. In case of any excess capacity credits PJM subsequently issues to ComEd, the IPA suggests ComEd sell its excess capacity credits and return the corresponding proceeds to its customers.

The 2013 Procurement Plan recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction. Table 7-12 shows how much capacity that strategy would require Ameren to procure, based on the July 2013 forecast.

Table 7-12 Ameren Estimated Capacity Requirements Expected Case Forecast

Delivery Year	Peak Load + Losses + Reserves	Capacity Required	2012 Purchase	Remaining Need
2014-2015	1,283	1,290	1,110	180
2015-2016	1,169	820	0	820
2016-2017	1,116	400	0	400
2017-2018	1,064	0	0	1,064
2018-2019	1,014	0	0	1,014

In 2013, MISO's first annual capacity auction cleared the entire capacity requirement and the 2014 auction should have the liquidity to supply the 180 MW Ameren will need. The IPA expects that auction to demonstrate sufficient liquidity that it will be unnecessary to purchase capacity for 2015-2017 bilaterally. The Agency therefore recommends there be no capacity procurement event in 2014. However, the IPA is also aware that MISO has a prompt year capacity auction whereas PJM has a three year forward capacity auction. If Ameren were to rely entirely on the prompt year capacity auction in perpetuity (with no bilateral procurements via the IPA), it could increase the chances that Ameren's eligible retail customers would be exposed to a scarcity pricing event whereby capacity prices rise abruptly and dramatically. The IPA therefore recommends that the procurement of bilateral capacity for Ameren be revisited in future Plans in the absence of a more robust forward looking MISO capacity auction.

7.5 Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures, providing that:

> *Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years.*

The energy efficiency and demand response programs for the three year period starting June of 2014 for Ameren and ComEd pursuant to Section 8-103 have not yet been filed, let alone approved by the ICC, so the IPA does not have concrete information regarding how the utilities will meet their demand response goals.

ComEd provided information regarding its existing demand response programs for 2012 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 71,900 customers with a load reduction potential of 87 MW (ComEd Rider AC).
- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,010 MW of potential load reduction (ComEd Rider VLR).
- Residential Real-Time Pricing (RRTP) Program: All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has roughly 5 MW of price response potential.
- Peak Time Savings (PTS) Program: This program is required by Section 16- 108.6(g) of the PUA and was recently approved by the ICC in Docket No. 12-0484. The PTS program is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commences with the 2015 Planning Year. ComEd recently sold 35 MW of capacity from the program into the PJM capacity auction for the 2016 Planning Year.

Ameren has a Voltage Optimization Pilot Program underway, offers the Power Smart Pricing real-time pricing program to residential customers, and has a proceeding underway before the Commission to approve a Peak Time Rebate program.

The IPA does not propose any additional demand response programs for the 2014-2015 delivery year. Peak Time Rebate (or Savings) programs create value through reduction in capacity charges. Given that the IPA has recommended that the utilities directly contract for capacity, the IPA does not have a direct role in the use of demand response to reduce capacity obligations. However, the technologies utilized for capacity reductions also have the potential to provide longer term demand response that could operate over more peak hours than those used for calculations of capacity obligations. With the ComEd Peak Time Savings program scheduled to commence in 2015, and the likely start-up of a similar program for Ameren, in 2016 the IPA invites stakeholders to provide comments to the IPA on how the Procurement Plan should include additional or complimentary demand response, and whether the roll-out of smart meters affects the timeline for additional programs.

7.6 Clean Coal

The IPA did not receive any requests for Clean Coal projects pursuant to Sections 1-58 or 1-75.

7.7 Summary of Strategy for the 2014 Procurement Plan

Table 7-13 summarizes the recommendations of this Chapter.

Table 7-13 Summary of 2014 Illinois Power Agency Procurement Plan Recommendations

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	**2014-15**	Up to 175MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except solar and DG), budget cap exceeded	Will be purchased from MISO
	2015-16	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2016-17	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2017-18	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2018-19	No energy procurement required	Direct purchase from MISO capacity market	Shortage of 10GWh but budget cap exceeded: no RPS procurement	Will be purchased from MISO
COMED	**2014-15**	Up to 1,175MW forecasted requirement (April Procurement) Up to 350MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	Shortage of 116GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM
	2015-16	Up to 375MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
	2016-17	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
	2017-18	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
	2018-19	No energy procurement required	Direct purchase from PJM capacity market	Shortage of 178GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

8 Renewable Resources Availability and Procurement

This chapter focuses on the procurement of renewable resources on behalf of eligible retail customers and also provides informational guidance on the IPA's considerations for the use of the Renewable Energy Resources Fund ("RERF"). Procurement on behalf of eligible retail customers is subject to targets for purchase volumes and upper limits on customer bill impacts, which, based on the load forecast, creates a cap on the available budget.

From 2009 through 2012, the IPA's annual electricity procurement plans included purchase of renewable energy resources sufficient to meet the RPS applicable to the eligible load of ComEd and Ameren. In 2013, the IPA determined that resources under contract were sufficient to meet the reduced eligible load. The RPS calls for the procurement of the following quantity of renewable energy resources and renewable energy credits as a mandatory part of each utility's annual supply: [113]

- At least 2% by June 1, 2008
- At least 4% by June 1, 2009
- At least 5% by June 1, 2010
- At least 6% by June 1, 2011
- At least 7% by June 1, 2012
- At least 8% by June 1, 2013
- At least 9% by June 1, 2014
- At least 10% by June 1, 2015

This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025.[114] The obligation of each electric utility is determined by applying the required percentage to the amount of eligible retail sales from the most recently completed delivery year. In addition, the RPS mandate includes targets for specific resource types: wind, photovoltaics (PV) and distributed generation (DG).[115]

The cap on the available RPS budget is defined as follows:

> *The amount of renewable energy resources procured pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011.*[116]

This section assesses the renewable resource volume and dollar budgets available for use to both utilities. The assumptions made below reflect the utility's expected load forecasts as described in Sections 3.2 and 3.3 and recommended by the IPA to be adopted by the ICC. If the ICC were to adopt a different load forecast, then the following analysis would have to be revised accordingly. Likewise, in a future delivery year the load forecast may be updated and differ significantly from what is shown here.

The IPA does not recommend procuring any additional renewable resources on behalf of Ameren or ComEd during the planning horizon. Furthermore, the IPA recommends (see Section 8.2.1) that the ICC order the utilities to produce updated load forecasts in March and to curtail the Long-Term Power Purchase

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[113] Renewable energy resources are defined as: "energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of [the IPA Act], landfill gas produced in the State is considered a renewable energy resource." 20 ILCS 3855/1-10.
[114] 20 ILCS 3855/1-75(2)(c)(1).
[115] 20 ILCS 3855/1-75(c)(1).
[116] 20 ILCS 3855/1-75(2)(c)(2)(E).

Agreements ("LTPPAs") if the updated forecast indicates the renewable budget will be exceeded. These forecasts will also be used to plan the Mid-April 2014 forward hedge procurement event (see Sections 7.2.1 and 7.2.3).

8.1 Current Utility Renewable Resource Supply and Procurement

8.1.1 Ameren

As shown in Table 8-1~~Table 8-1Table 8-1~~, Ameren's current renewable contracts will cover its RPS targets for the next four Delivery Years. Assuming that no additional purchases of renewable energy are made, Ameren will fall short of meeting its RPS requirements in the 2018-2019 delivery year by less than 2%.

The Illinois Power Agency Act also sets separate goals for wind, photovoltaic and distributed renewable generation as fractions of the total renewables requirement.[117] Table 8-1~~Table 8-1Table 8-1~~ shows that Ameren is projected to meet its wind generation goals for the next five delivery years, but, assuming that no additional purchases of PV and DG are made, Ameren will fall short of the photovoltaic and distributed generation goals in each year. Ameren is also projected to exceed its spending cap on renewables (Table 8-3~~Table 8-3Table 8-3~~). As a consequence the IPA does not recommend procuring any additional renewable resources on behalf of Ameren during the planning horizon nor does the IPA recommends the sale of any renewable resources that exceed targets.

Table 8-1 Ameren's Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2014-15	Target (MWh)	949,030	711,773	28,471	7,118
	Purchased MWh	1,025,366	949,672	8,694	0
	Remaining Target (MWh)	-76,336	-237,899	19,777	7,118
2015-16	Target (MWh)	540,550	405,412	32,433	5,405
	Purchased MWh	1,008,810	979,916	8,894	0
	Remaining Target (MWh)	-468,260	-574,504	23,539	5,405
2016-17	Target (MWh)	544,472	408,354	32,668	5,445
	Purchased MWh	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	-484,773	-568,497	20,274	5,445
2017-18	Target (MWh)	572,930	429,697	34,376	5,729
	Purchased MWh	854,396	848,338	6,058	0
	Remaining Target (MWh)	-281,466	-418,641	28,318	5,729
2018-19	Target (MWh)	607,991	455,993	36,479	6,080
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	7,991	-140,578	33,050	6,080

8.1.2 ComEd

Table 8-2~~Table 8-2Table 8-2~~ shows ComEd's current RPS contracts relative to its renewables requirements. ComEd's forecast indicates that it has a relatively small shortage of 116GWH of renewables for the 2014-2015 delivery year. However, ComEd expects to exceed the renewables cost cap (Table 8-4~~Table 8-4Table 8-4~~) and therefore cannot procure any additional renewables. Based on current forecasts, ComEd will meet its RPS requirement, with comfortable surpluses, in the next three years.

The IPA does not recommend procuring additional renewable resources on behalf of ComEd during the planning horizon.

[117] 20 ILCS 3855/1-75(2)(c)(1).

Table 8-2 ComEd's Existing RPS Contracts vs. RPS Requirements

	Total Renewables			Other Targets (MWh)		
Delivery Year	**Target (MWh)**	**Purchased MWh**	**Remaining Target (MWh)**	**Wind**	**Photo-voltaics**	**Distributed Generation**
2014-15	2,001,744	1,885,302	116,442	1,501,308	60,052	15,013
2015-16	1,171,086	1,464,204	(293,118)	878,315	70,265	11,711
2016-17	1,198,607	1,561,397	(362,790)	898,955	71,916	11,986
2017-18	1,300,312	1,533,198	(232,886)	975,234	78,019	13,003
2018-19	1,439,620	1,261,725	177,895	1,079,715	86,377	14,396

Table 8-2~~Table 8-2Table 8-2~~ includes ComEd's statutory targets for wind, photovoltaic and distributed renewable procurement over the five-year projection horizon. The rate cap described above prevents procurement of these or any other resources on behalf of eligible retail customers as long as the cap is exceeded.

Note that the significant decrease in RPS target observed between Delivery Years 2014-2015 and 2015-2016 reflects the drop in eligible load that occurred between Delivery Years 2012-2013 and 2013-2014. The statutory RPS obligations of Ameren and ComEd are determined by their amount of actual eligible retail sales two years earlier.

8.2 LTPPA Curtailment

8.2.1 Impact of Budget Cap

As noted above, the Illinois Power Act includes a limit on each utility's spending on renewable procurement. For the 2013-2014 delivery year, the ICC approved the curtailment of Ameren's and ComEd's existing long-term renewables contracts to keep the cost of renewable energy resource under the statutory cap. This approval was subject to the March 2013 forecast indicating the renewable budget was exceeded.[118] Since ComEd's March 2013 forecast indicated that its budget was exceeded and Ameren's was not, ComEd initiated curtailments whereas Ameren did not (Ameren's current forecast suggests they will be obliged to curtail in the coming years). This section addresses the utilities' committed RPS contracts relative to the spending cap and possible curtailment for the 2014-2015 and subsequent delivery years.

Table 8-3 Required Reductions (Curtailments) of Long-term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, Ameren

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2014-15	9,167,145	8,547,742	619,403	8,155,000	7.6%
2015-16	9,183,529	7,956,671	1,226,858	7,826,000	15.7%
2016-17	10,403,861	7,570,119	2,833,742	7,796,000	36.3%
2017-18	9,412,155	7,216,201	2,195,954	7,957,000	27.6%
2018-19	8,000,000	6,860,913	1,139,087	8,000,000	14.2%

Table 8-3~~Table 8-3Table 8-3~~ indicates that under its current RPS contracts and given the expected load forecast, Ameren is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon.

[118] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 110, 67-68.

Table 8-4 Required Reductions (Curtailments) of Long-Term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2014-15	24,272,678	19,716,565	4,556,113	23,189,000	19.6%
2015-16	23,159,931	18,921,538	4,238,393	22,613,000	18.7%
2016-17	23,483,757	18,781,575	4,702,182	22,676,000	20.7%
2017-18	23,776,890	18,875,753	4,901,136	23,139,000	21.2%
2018-19	23,415,145	18,980,868	4,434,278	23,358,000	19.0%

Table 8-4~~Table 8-4Table 8-4~~, which is similar to Table 8-3~~Table 8-3Table 8-3~~, shows ComEd's contractual RPS supplies and cost relative to the cost cap, given the expected load forecast. Like Ameren, ComEd is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon – as it did in the current delivery year, forcing curtailment of ComEd's LTPPAs.

The spending caps will prevent ComEd and Ameren from committing any additional money to procure renewables for the 2014-2015 delivery year, including specific procurements of wind, photovoltaic and distributed renewables. As noted above, in future years if the load forecast is significantly different, then these caps may cease to apply. But for the purposes of this plan, the spending caps clearly preclude the procurement of renewable energy resources in 2014.

Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory cap. Therefore, the purchases under the long term renewable contracts will need to be reduced as shown in the tables above. An estimate of the overall amount is shown in this Plan for both Ameren and ComEd, however the exact amount is uncertain at this time. Both utilities will be submitting updated forecasts in March 2014. Once the Commission has approved this Plan, including the incremental energy efficiency program amounts, and the utilities have submitted further updated forecasts in March 2014 to reflect municipal aggregation activity and any Commission-approved energy efficiency programs, each utility should calculate both the overall amount of the necessary reduction to keep the purchases under the statutory cap, and determine the amount that each long term renewable contract will need to be reduced. Any such reductions should be applied proportionately to the long term renewable contracts consistent with the terms of the contracts. This calculation should only be made for the 2014-15 delivery year. Future procurement plans will address the need, if any, for additional reductions.

The updated March 2014 forecast and related calculations of the curtailments (if any) should be submitted to both the IPA and the Commission Staff for their review and acceptance. Once the utilities have received written acceptance from both the IPA and the Commission Staff, the utilities may then notify the suppliers under the long-term renewable contracts of the amounts of the reductions. The suppliers will then make the election allowed them under the agreements. Because the reductions under the IPA Act are to be made on the basis of the "estimated" net increase in charges to Eligible Retail Customers, no further reductions in purchases of renewable under the long-term contracts for delivery year 2014-2015 will be made based on either the suppliers' elections or the actual increases in charges experienced by Eligible Retail Customers during the 2014-2015 delivery year.

As the ICC ordered in its approval of the 2013 Procurement Plan, the IPA recommends March 2014 updates to both utilities' load forecasts. These forecasts will form the basis for curtailment upon consensus of the utilities, IPA, ICC Staff, Procurement Administrator(s) and Procurement Monitor. To the extent that the ICC authorizes block energy procurements for ComEd (as recommended in Chapter 7 above) or Ameren, the IPA notes that additional load forecasts will be required in anticipation of the procurement event and the load forecast should not be duplicated. As with Ameren's March 2013 load forecast, one or both of the utilities may have unanticipated changes in their respective load forecasts from the previous forecasts such that curtailments are not warranted.

8.3 Alternative Compliance Payments

8.3.1 Use of Hourly ACPs Held by the Utilities

As described in Chapter 2, the utilities collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility[119]. Unlike the ACP funds paid by ARES into the RERF and discussed in Section 8.3.2~~8.3.28.3.2~~ below, the utility hourly customer ACP funds are held by the utilities[120]. As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held; for Ameren, the value is $1,800,484; for ComEd, the value is $4,099,937.

The IPA Act requires the ACP funds from utility hourly customers to: "increase [the utility's] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31."[121] In the ICC's Final Order in the 2013 Procurement Plan approval docket, the ICC accepted the IPA's proposal that the utility hourly customer ACP funds should be used to purchase curtailed RECs at the imputed REC price.[122] As approved by the Commission in Docket No. 09-0373, the imputed REC price under the bundled renewable contracts is equal to the difference between the Contract Price and the forward price curve for each respective load zone for a particular year, as developed by the Procurement Administrator in 2010.[123]

During the pendency of the approval docket for the 2013 Procurement Plan, the IPA and several stakeholders anticipated that the LTPPA contracts entered into by both Ameren and ComEd could face curtailment. In the end, only ComEd implemented an ICC-approved curtailment.[124]

In the event that the Commission approves curtailments based on March 2014 load forecasts, and after consensus of the aforementioned parties then the IPA recommends that the Commission once again approve use of the utility hourly customer ACPs to purchase curtailed RECs at the imputed REC price. While several parties argued that using these funds could be counter to the statute and could be construed as a supplier subsidy by utility hourly priced customers, the Commission agreed with the IPA that this was an appropriate use of funds and the IPA again asks for the same approval in this Plan. If, due to load shifts or change in law, the ICC does not approve curtailments and does approve additional procurements, then the IPA recommends that the Commission authorize the IPA to use those funds to supplement any renewable resource procurements.

If the ICC approves procurements of multiple renewable resource products for a single utility, then the IPA respectfully requests that the ICC authorize use of the utility hourly customer ACP funds to the highest renewable resource procurement priority.

8.3.2 Use of ACPs Held by the IPA

As of this report date, the RERF balance equals $14,911,284.40, the total amount received in the Agency's RERF attributable to ARES ACP payments. Table 8-5~~Table 8-5Table 8-5~~, below, shows the current IPA RERF balance sheet. In September 2013, the IPA expects to receive an estimated $40 million in ACPs for the June 2012 – May 2013 planning year. These expected payments, in the aggregate, are significantly higher than prior year payments. The higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

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[119] *See* 20 ILCS 3855/1-75(c)(5).
[120] See id.
[121] Id.
[122] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 110-111, 114-115.
[123] *See* Appendix K (pp. 2-3) to IPA's Load Forecast for Five-Year Planning Period June 2010 – May 2015, as approved by the Commission in Docket No. 09-0373.
[124] *See, e.g.*, *id.* at 110 (noting likelihood of Ameren curtailment based on Ameren's November 2012 load forecast).

Table 8-5 RERF Balance

Planning Year	Funds Received	Total ACPs
2009-10	2010 - Quarters 3 and 4	$7,148,261.61
2010-11	2011 - Quarters 3 and 4	$5,606,245.18
2011-12	2012 - Quarters 3 and 4	$2,156,777.61
Aggregate Total		**$ 14,911,284.40**

The ICC has held that it does not have jurisdiction over the RERF, and as a result the IPA is not seeking approval for procurement using the RERF.[125] However, for informational purposes, the IPA believes it would be beneficial to explain its plans for spending the RERF and allow the ICC and stakeholders to coordinate the ICC jurisdictional Procurement Plan spending with the IPA's RERF spending.

As the IPA noted in the 2013 Procurement Plan docket, the IPA faces statutory and practical barriers to spending the RERF absent a procurement event on behalf of eligible retail customers. The IPA has worked with stakeholders on the elements of a legislative solution to address the problems inherent in the statute as currently written. To briefly summarize, Section 1-56 of the IPA Act authorizes spending of the RERF on the same products procured for utility customers at the same or lesser price. In the absence of a procurement event for eligible retail customers, there are no "same products" and no price target.[126] Furthermore, even if the IPA were to ignore these statutory requirements, the IPA does not have the statutory authority to recover the significant costs of a procurement (the statute apparently envisioned the RERF as an add-on to budget for a utility procurement) and does not have the authority to create an enforceable cost-based benchmark with the ICC.[127] As a result, absent a change in law to address these issues or a procurement on behalf of eligible retail customers, the IPA does not believe that it can spend the RERF on anything except curtailed RECs.

- If there are no changes in law and the ICC does not authorize renewable resource procurements on behalf of eligible retail customers, then the IPA will plan to spend some of the RERF funds on curtailed RECs on a one-year basis. The IPA is currently taking this action for RECs curtailed by ComEd in the current delivery year. In the current year, the IPA plans to purchase up to 121,620 curtailed RECs at a total expected cost of up to $2.24 million
- If there are no changes in law and the ICC does authorize renewable energy resource procurements on behalf of eligible retail customers, then the IPA will use some or all of the RERF to expand the budget for the procurements according to the IPA's highest product priorities
- If there are changes in law sufficient to allow the IPA to procure renewable energy resources at the IPA's discretion and not necessarily in conjunction with a utility procurement, then the IPA plans to spend funds from the RERF in accordance with the provisions of Section 1-56(b). In particular the IPA will seek to achieve the goals for procuring solar and distributed renewable energy resources. Section1-56(b) also specifies that 75% of resources procured come from wind. The IPA will analyze the quantities of wind procured via the purchase of curtailed RECs described above and will fill the balance of the requirement with RECs from existing wind energy facilities.

To the extent that the ICC authorizes a procurement event on behalf of eligible retail customers and the IPA also has discretion to procure renewable resources using the RERF, then the IPA plans to work with the ICC and stakeholders to ensure coordination between procurement events and products procured to minimize expenditure of resources and meet state renewable targets.

[125] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114.
[126] *See* 20 ILCS 3855/1-56(c) and (d).
[127] *Compare* 20 ILCS 3855/1-56 *with* 20 ILCS 3855/1-75(g)-(h) (explicitly authorizing fee assessment and cost recovery) *and* 220 ILCS 5/16-111.5(e)(3) (explicitly setting out benchmark as price-not-to-exceed).

8.4 Changes in Law

In the draft plan for public comment released on August 15, 2013, the IPA set out a priority list for renewable resource procurement. As noted above, the load forecasts for Ameren and ComEd indicate that there will be a curtailment in the LTPPAs during the upcoming delivery year. As a corollary, the renewable resource budgets will be exceeded for each utility and thus no procurements will take place. Although the IPA continues to recommend the prioritization set forth in the August 15, 2013 public comment draft plan, the IPA will remove the discussion because potential statutory changes are insufficiently definite to provide a meaningful backdrop for discussion at this point in time.

9 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5. The procurement administrators, retained by the Agency in accordance with 20 ILCS 3855/1-75(a)(2), conduct the competitive procurement events on behalf of the IPA. The costs of the procurement administrators incurred by the Illinois Power Agency are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees assessed by the IPA. As a practical matter, the utility "eligible retail customers" ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the Agency and the procurement administrators have reviewed the process for potential improvements.

Section 16-111.5(e) of the Public Utilities Act specifies that the procurement process must include the following components:

(1) Solicitation, pre-qualification, and registration of bidders.

> *The procurement administrator shall disseminate information to potential bidders to promote a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks, provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency's and the Commission's websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.*

(2) Standard contract forms and credit terms and instruments.

> *The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.*

(3) Establishment of a market-based price benchmark.

> *As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference. The price benchmarks may also be adjusted to take into account differences between the information reflected in the underlying data sources and the specific products and procurement process being used to procure power for the Illinois utilities. The benchmarks shall be confidential but shall be provided to, and will be subject to Commission review and approval, prior to a procurement event.*

(4) Request for proposals competitive procurement process.

> *The procurement administrator shall design and issue a request for proposals to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The request for proposals shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price.*

(5) A plan for implementing contingencies.

> *[i]n the event of supplier default or failure of the procurement process to fully meet the expected load requirements due to insufficient supplier participation, commission rejection of results, or any other cause.*

Of these five process components, the area with the greatest potential for efficiency improvements resulting in lower costs passed along to ratepayers is item (2): development of standard contract forms and credit terms and instruments. The IPA believes that the forms can be further standardized while remaining acceptable to future potential bidders, thus reducing procurement administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because the forms, terms and instruments have become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. The IPA also notes that the contracts with the incumbent procurement administrators have expired and the IPA will be conducting a competitive procurement process for a new procurement administrator starting this fall. There may be additional cost savings to be realized by having a single procurement administrator rather than a different administrator for each utility.

Any procurement process to be conducted under the auspices of the 2014 Procurement Plan would be the seventh iteration of IPA-run procurements, when including the February 2012 Rate Stability procurements and the December 2010 long-term REC and energy procurement. In each of the prior iterations, potential bidders have had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. In the two procurements conducted in 2012 (the Rate Stability Procurement and the standard Spring Procurement) comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurements). The documents used for the 2012 IPA-run procurements illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves.

On the opposite side of this discussion, the IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection of the utilities, utility customers and suppliers. The IPA therefore recommends that the energy contracts used in the February 2012 Rate Stability procurements be the starting point for the contracts used in the energy procurements associated with this plan.

The IPA plans to work with the Procurement Administrator, the Procurement Monitor, the Commission and other stakeholder to implement additional procurement process improvements suggested in comments that may include the following:

- Schedule procurements for the early part of the week. Energy markets are more volatile for a period of time prior to and after the gas storage numbers come out every Thursday.
- Reduce the length of time between submission of bids and notification of likely bid award to the greatest extent possible decreases the risk that suppliers bear, which would likely lead to lower overall bid prices.
- Hold REC procurements within days of the energy procurements to expedite the release of tariff changes resulting from these procurements. Delays in the release of the tariffs and charges cause substantial confusion and potential competitive harm in the retail market.

Section 16-111.5(o) of the PUA states,

> *On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.*

There have been no procurements in 2013, therefore no informal comment process was conducted this year. Comments from previous informal hearings are available of the Commission's web site.

Appendices

Appendix A. Regulatory Compliance Index

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix B. Ameren Load Forecast Documents

Available as separate files at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Supplemental Documents

- Section 16-111.5B Submittal (includes Appendices 1 and 3. Appendices 6 and 7 have been marked "Confidential")

- Appendix 2: Workshop Summary

- Appendix 4: AIC Potential Study
  - Volume 1: Executive Summary
  - Volume 2: Market Research
  - Volume 3: EE Potential Analysis
  - Volume 4: Program Analysis
  - Volume 5: Supply Curves

- Appendix 5: AIC Third Party RFP

Appendix C. ComEd Load Forecast Document

Available as separate files at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Supplemental Documents

- Appendix C-1: Potential Study
- Appendix C-2: Energy Efficiency Analysis Summary
- Appendix C-3: Monthly Savings Curves
- Appendix C-4: Program Details
- ComEd 2013 Third Party Efficiency Program Summary of Vendor Scoring Process, July 5, 2013 (Marked "Confidential")

Appendix D. Ameren Load Forecast and Supply Portfolio by Scenario

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

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Appendix E. ComEd Load Forecast and Supply Portfolio by Scenario

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix F. Description of Monte Carlo Model

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix G. Numerical Values of Purchased Energy Adjustments, in $/MWh

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix H. Department of Commerce and Economic Opportunity Section 16-111.5B Submittal

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx