REBUTTAL TESTIMONY

OF

RICHARD J. ZURASKI

Senior Economist

Illinois Commerce Commission

Energy Division—Policy Section

**Central Illinois Light Company d/b/a AmerenCILCO,
Central Illinois Public Service Company d/b/a AmerenCIPS,
and Illinois Power Company d/b/a AmerenIP**

Docket Nos. 05-0160/05-0161/05-0162 (Consolidated)

**Proposals to implement a competitive procurement process
by establishing Rider BSG, Rider BSG-L, Rider RTP,
Rider RTP-L, Rider D, and Rider MV.**

August 10, 2005

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I. Witness Qualifications

Q. State your name and business address.

A. Richard J. Zuraski, Illinois Commerce Commission, 527 East Capitol Avenue, Springfield, Illinois, 62701.

Q. Are you the same Richard J. Zuraski who submitted direct testimony in this docket on behalf of the staff of the Illinois Commerce Commission ("Staff")?

A. Yes.

II. Purpose of Testimony

Q. What is the subject matter of your rebuttal testimony?

A. My rebuttal testimony concerns filings by Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company, (collectively, "Ameren" or the "Company") of certain tariff changes. According to Ameren, the revised tariff sheets (1) define and establish the generation services that Ameren will provide upon the expiration of the mandatory transition period, effective January 2, 2007; (2) establish the procurement process by which Ameren will obtain the power supply necessary to provide those generation services; and (3) establish the methodology by which the auction prices will be translated into prices that customers will pay. (Resp. Ex. 1.0, pp. 3-4, lines 36-63) My rebuttal testimony will address portions of the direct testimony of several intervenor witnesses and the rebuttal testimony of several Company witnesses, including: People of the State of Illinois through the Office of the Attorney

General of the State of Illinois ("AG") witness Harvey Salgo; Coalition of Energy Suppliers ("CES") witness Philip R. O'Connor, Citizens Utility Board and the Cook County State's Attorney's Office ("CUB/CCSAO") witnesses Robert M. Fagan and William Steinhurst; and Direct Energy Services, LLC and U.S. Energy Savings Corp. ("DES-USESC") witness James Steffes; and Ameren witnesses Craig D. Nelson, James C. Blessing, and Wilbon L. Cooper. More specifically, my rebuttal testimony addresses the issues identified in the following table:

Witness(es)	Issue(s)
AG witness Salgo	His concern with the choice of procurement model.
	His concern with the choice of contract durations.
CES witness O'Connor	His proposal to remove the 400 kW to 1 MW customers from the BGS-FP segment.
CUB/CCSAO witness Fagan	His concerns with the wholesale market for electricity.
CUB/CCSAO witness Steinhurst	His recommendations to reject the auction, open a new docket to consider a full range of procurement options, and affirm that retail rates remain subject to traditional regulatory standards of justness and reasonableness.
	His concerns regarding the competitiveness of the wholesale market for electricity.
	His concerns about renewable resource and energy efficiency procurement.
DES/USESC witness Steffes	His concern with the choice of contract durations.
Ameren witnesses Nelson and Blessing	Company's proposal pertaining to Staff's role in overseeing the auction.
Ameren witnesses Blessing and Cooper	Company's position with respect to CES witness O'Connor's proposal to remove the 400 kW to 1 MW customers from the BGS-FP segment.

III. Choice of Procurement Model

Q. AG witness Salgo and CUB/CCSAO witness Steinhurst express concerns with the Company's choice of procurement model -- namely, the type of "vertical tranche" simultaneous descending clock auction ("SDCA") that has been used by several New Jersey electric utilities over the last several years ("the NJ model"). Mr. Salgo recommends that the "Commission require Ameren to present a complete analysis of the rate impacts and risk levels for bundled customers associated with its proposed portfolio design and procurement method, compared with a variety of other portfolio design and procurement options." (AG Exhibit 2.0, p. 23, lines 16-19) Dr. Steinhurst recommends that the Illinois Commerce Commission ("Commission"): "[r]eject the Companies' proposal," and "[o]pen a new docket to consider the full range of procurement options." (CUB-CCSAO Exhibit 2.0, p. 8, lines 168-170) Do you have a response to these recommendations?

A. Yes, I do. I recommend that the Commission reject these proposals. In my opinion, these witnesses have not provided a sound or reasonable basis to "[r]eject the Companies' entire auction proposal" and "[o]pen a new docket to consider the full range of procurement options." First, there was nothing stopping parties that oppose the NJ model from presenting alternative models in the context of this proceeding. In this regard, it could not have been a surprise--especially to anyone who was involved in the Commission's Post 2006 Initiative last summer--that the Company would be making a post 2006 procurement filing toward the beginning of 2005, and that it would likely propose something close to the NJ model. In any event, the clock has been and continues to be ticking, bringing us closer to the post 2006 era. The AG and CUB/CCSAO should have come to this proceeding prepared to present their alternatives to the NJ model rather than with proposals to further delay the inevitable need to make decisions on viable procurement approaches. Second, the Company, in its rebuttal testimony, has more fully compared the NJ model to several other procurement concepts and has adequately justified the use of the NJ model.[1] Third, I generally share the views expressed in "The Post-2006 Initiative: Final Staff Report to the Commission," released in November 2004 ("Staff Report"), which supports the use of the NJ model. For instance, I agree with the following statements from the Staff Report:

> In Staff's view, for procuring supply for large electric utilities that own little to no generation capacity (having spun off most or all of their generation assets), a vertical tranche auction (as explained in the subsections, below) would best mitigate the affiliate and market power concerns described above. … Furthermore, for utilities with generation affiliates, the vertical tranche auction model apparently would satisfy the Federal Energy Regulatory Commission's ("FERC's") "Edgar standard" regarding arms-length transactions. The Edgar standard requires that a utility prove that any deal it makes with its affiliate was entered into through a procurement process that was transparent, nondiscriminatory, and clearly defined, contained standardized evaluation criteria, and was administered by an independent third-party. Indeed, of the procurement scenarios explored in the workshops, the vertical tranche auction most directly addresses concerns about utilities buying from their affiliates.[2]

> …

[1] See Resp. Ex. 10.0, pp. 29-33; and Resp. Ex. 11.0 (Revised), pp. 3-21.

[2] Staff Report, p. 10.

> In Staff's view, vertical tranche auctions provide a viable means of achieving the five overarching policy goals for a preferred procurement methodology:
>
> - Mitigation of market structure problems;
> - Provision of regulatory certainty;
> - Provision of market based prices and rate stability;
> - Provision of a straightforward mechanism to convert a wide variety of supply acquisition costs into retail rates using traditional rate design; and
> - Provision of a working option by January 2007.[3]
>
> …
>
> In terms of dealing with market power and affiliate abuse concerns, the transparency of the vertical tranche auction is its central strength. This transparency is provided by the uniformity of the auctioned vertical tranche full requirement product as well as the bidding mechanism of the auction. Relative to requests for proposal (which are bilateral processes traditionally used in the Midwest for the procurement of electricity), an auction for a uniform product increases the comparability of offers. The comparability of the offers, in turn, increases competition among suppliers and provides transparency to the process. Suppliers are, in the end, evaluated solely on the price upon which they can supply a pre-defined product. Since all potential suppliers are ultimately judged on the same observable criterion, this minimizes the potential for utilities to provide favorable treatment to their affiliates, and reduces the burden of regulatory oversight. The bidding mechanism also provides a means for bidders to have their bids considered objectively, fairly, and simultaneously, further adding to the transparency to the process.[4]

Q. Notwithstanding his recommendation to "[o]pen a new docket to consider the full range of procurement options," Dr. Steinhurst also recommends that the Commission "…reject the competitive procurement and require

[3] Staff Report, p. 12.

[4] Staff Report, p. 12.

Ameren to procure least cost power under traditional cost recovery standards. Such procurement would be subject to traditional ratemaking standards." (CUB-CCSAO Exhibit 2.0, p. 18, lines 393-395) Do you concur with this recommendation?

A. I have to disagree with rejecting "competitive procurement" in favor of such a vague alternative as requiring Ameren "to procure least cost power meeting such standards as the Commission may impose, … subject to traditional rate making standards." Indeed, it is unclear if Dr. Steinhurst's proposed alternative is even different than "competitive procurement." First, "to procure least cost power" is a goal and not a procurement method or process. Second, that goal is not inconsistent with using a competitive procurement process. Third, Dr. Steinhurst not only fails to explain what he means by "traditional rate making standards", but he also fails to explain how using an auction or using a translation tariff is inconsistent with such traditional standards. In short, there is no basis for the Commission to accept Dr. Steinhurst's recommendations, because they lack substance.

Q. Dr. Steinhurst states, "The Ameren Companies have 'publicly stated that they presently anticipate average rate increases in the range of 10-20% for Illinois electric operations as a whole.' Ameren Resp. to CUB DR 1.32. This is an increase in the bundled rate due only to the power supply component." (CUB-CCSAO Exhibit 2.0, p. 13, lines 282-285) How do you respond to this statement?

A. Although some may find it distressing that rates could rise by such degrees, it is unclear how the Commission can utilize Dr. Steinhurst's assessment in this case. The fact of the matter is that, pursuant to the Customer Choice and Rate Relief Law of 1997, the Company was allowed to divest itself of its generating assets. Thus, unless the generating assets are bought back by the Company, the historical cost of those plants and the cost of operating them cannot directly form the basis for a reassessment of the Company's rates following the rate freeze. These plants are now a part of "market" supply. From the Company's perspective, the cost of producing power and energy from these plants is not and may never again be determined by an accounting of the cost of building and operating the plants. From the Company's current perspective, the cost of acquiring power and energy from these plants (or from any outside source) is determined by the market.

Obviously, it would be desirable for ratepayers if wholesale suppliers could be convinced to provide power and energy to Illinois utilities at below-market prices. However, it is highly unlikely and unrealistic to assume that the Company can acquire power and energy at below-market prices, and Dr. Steinhurst provides no viable plan for making it happen.

IV. Concerns with the Wholesale Market

Q. CUB/CCSAO witnesses Fagan and Steinhurst express concerns about the wholesale market for electricity (CUB-CCSAO Exhibit 1.0, pp. 5-21; and CUB-CCSAO Exhibit 2.0, pp. 11-12) and Dr. Steinhurst states that the proposed auction process "absolutely" assumes and depends on a fully

competitive wholesale electricity market (CUB-CCSAO Exhibit 2.0, pp. 11, lines 234-236). How do you respond to this testimony?

A. I am not going to comment directly on the competitiveness of the wholesale market for electricity. However, even assuming, for the sake of argument, that the wholesale market is not competitive, that would not change the facts that (i) Ameren has an obligation to provide power and energy to most of its retail customers and (ii) the only conceivable place that Ameren will be able to acquire power and energy for delivery beginning in 2007 is the wholesale market. Furthermore, even if the wholesale market is not competitive, Mr. Fagan and Dr. Steinhurst have not explained why the NJ model should be rejected. That is, they have not explained how an alternative procurement process would somehow circumvent a less-than-competitive wholesale market and produce a more favorable result for ratepayers.

V. <u>Contract Durations</u>

Q. DES/USESC witness Steffes and AG witness Salgo express some concerns with Ameren's choice of contract durations for the BGS-FP segment (3-year contracts). Mr. Steffes recommends 3-month contract durations. (DES/USESC Ex. 1.0, p. 9, lines 176-183) Finally, Mr. Salgo states that "in principle, I am not opposed to longer term contracts. In this situation, however, the Company has not presented a rationale for 'testing' the market for three year, full requirements, fixed price contracts." (AG Exhibit 2.0, p. 14, lines 15-17) Mr. Salgo goes on to recommend that the Company

perform an analysis of contract durations. (Id., p. 15) Do you concur with the recommendations of any of these witnesses?

A. No. Staff has not objected to Ameren's proposed 3-year contract durations. However, Staff would object to utilizing longer-term contracts without also adding some shorter-term contracts to the portfolio mix. Like Mr. Steffes (DES/USESC Ex. 1.0, p. 8, line 163-169), I am concerned with using long-term contracts, particularly in the first Illinois procurement auction. Notwithstanding those concerns, since the first auction will include some 1-year and 2-year contracts, as part of the Company's planned transition to an annual mixing of laddered 3-year contracts, I support the Company's contract duration proposal at this time. I also disagree with Mr. Steffes' more extreme recommendation of using only contracts of one month duration for customers above 15,000 kWh and three months duration for all customers with annual usage below 15,000 kWh.[5] (DES/USESC Ex. 1.0, p. 9, line 176-183) Finally, with respect to AG witness Salgo's recommendation that the Company perform an analysis of contract durations, it is not clear what Mr. Salgo wants the Company to do that the AG could not do itself, with the aid of Mr. Salgo or other experts. I share his desire for a thoughtful consideration of the options for defining the products to be acquired through the auction. However, I do not understand why it cannot be done in the context of the current docket.

[5] Note: Between 2003 and 2004, the average annual use per residential customer for the four Ameren electric distribution companies in Illinois ranged between 10,000 and 11,500 kWh.
(Source: Illinois Electric Utilities: Comparison of Electric Sales Statistics For Calendar Years 2004 and 2003, Prepared by the Financial Analysis Division, Illinois Commerce Commission, p. 12, http://www.icc.illinois.gov/ec/docs/050603ecSalesStats.pdf).

Q. Please summarize your concerns with including longer-term contracts in the first Illinois procurement auction?

A. First, the price of the longer-term contracts may entail an excessive risk premium. Second, if there is a significant expected upward or downward trend in market prices, the longer-term contracts will induce uneconomic retail switching activity. Third, as with any new process, the possibility of discovering problems or errors is higher for the initial implementation of the auction and will diminish over the course of subsequent auctions as problems are discovered and remedied on a going-forward basis. However, the length of time that is required before any remedial measures can take effect generally will be tied to the length of the supply contracts. In this regard, it may make more sense to test the waters with shorter-term contracts until all the problems with the auction (if any) have been identified and, if possible, eliminated or ameliorated.

Q. Please explain how the price of the longer-term contracts may entail a higher risk premium.

A. Note that the Company's proposed supplier contracts place all quantity risk on suppliers by obligating the supplier to provide a fixed percentage or share of the utility's annual load for a particular customer group or segment. Although suppliers will be provided data that will allow them to estimate the amount of energy that will be required for a given percentage of load, a supplier could end up being called upon to provide significantly less or significantly more than that estimated quantity. The difference may be due to a number of factors including unanticipated weather patterns, migration, business cycles, implementation of renewable resource and/or energy conservation policies, or switching by customers to or from other utilities or alternative retail electric suppliers ("RESs").

At the same time, the greater the share of load served by longer-term contracts the greater the chance that the Company's average portfolio price (at any point in time) will deviate by any given amount from the prevailing short-term market price. This, in turn, increases the risk of switching either from Company supply to RES supply (when short-run prices are below the Company's average portfolio price) or from RES supply to Company supply (when short-run prices are above the Company's average portfolio price). In this regard, it is important to remember that customers with peak demand less than 1 MW have few restrictions on switching between Company supply and RES supply (with one notable exception being that customers returning from RES supply to Company supply are obligated to remain for 12 months).

Presumably, the longer the contract term, the larger will be the supplier's risk, and the larger will be the risk premium embedded in the final auction clearing price.

Q. Have you quantified this risk?

A. Yes. I performed two quantitative analyses. The first uses an option pricing model. The second uses an alternative approach, which I will describe later in this testimony. I note that my analyses are intended to provide an assessment of the potential risk and are not an attempt to forecast the precise level of risk premiums that will be embedded in long-term contracts purchased through the proposed auction. Based on these analyses, I conclude that there could be significant risk premiums embedded in the prices, if long-term vertical tranche type contracts are utilized. For example, five-year contracts may include percentage premiums in the mid-teens, even where there is a zero expected market price trend. The risk premium increases as a function of market price volatility and decreases with the size of switching transaction costs (or any factors that inhibit switching).

Q. Please describe your analysis based on option pricing.

A. Options are financial tools that enable their owners to limit risks. For example, a call option on a common stock can be used to lock in a price for purchasing that stock at some point in the future, while a put option on a common stock can be used to lock in a price for selling that stock at some point in the future. The option premium (the price of the option itself) is a measure of the value of transferring that risk to the seller of the option. There are also options on futures. In Docket 05-0159, Commonwealth Edison Company ("ComEd") panel witnesses Alongi and Crumrine use a pricing model for options on futures to allocate between customer classes the estimated premium for switching risk that may be embedded in the clearing prices from the supply auction.[6]

Using a similar approach, I estimated switching risk premiums for each of five 1-year electricity contracts beginning after 1 month, 13 months, 25 months, 37 months, and 49 months, respectively, from the time that the option is purchased. As employed by Mr. Alongi and Mr. Crumrine, I assumed a 23% annual volatility in the underlying contract and used the same formula for

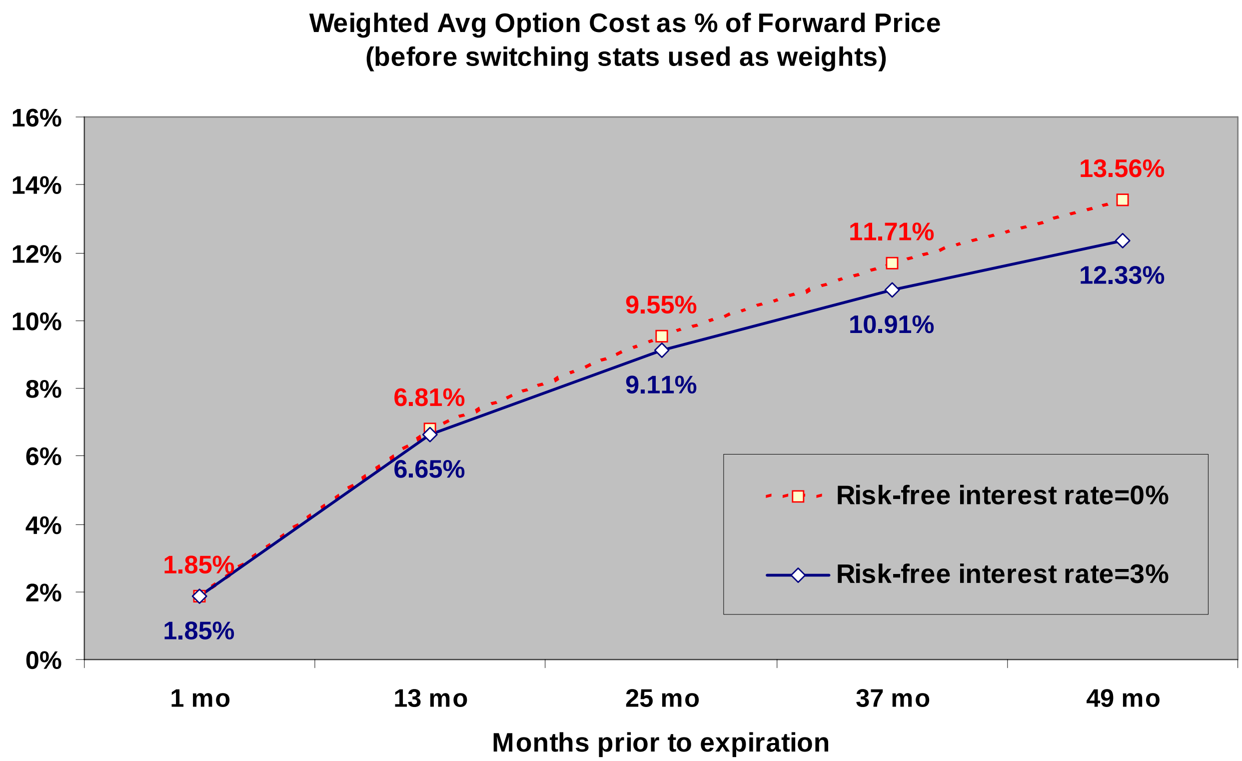
[6] Docket 05-0159, ComEd Exhibit 7.6.

computing the price (or premium) of a call option.[7] Also, like the analysis of Mr. Alongi and Mr. Crumrine, the strike price of these options (the price at which the customer has the option to buy) was determined endogenously so that the sum of the forward price and the option premium would equal the option strike price.

Q. What are the results from your option pricing analysis?

A. The results are expressed as a percent of the forward price. As shown below, the premium for an option for a 1-year supply contract expiring in one month is 1.85% of the prevailing forward price, while an option expiring after 4 years rises to between 12.33% and 13.56% (assuming a 3% and 0% risk-free interest rate, respectively). I provide both a 0% and a 3% interest rate to show how a higher interest rate lowers the value of the option. While ComEd witnesses Alongi and Crumrine used a 0% rate in their option pricing analysis, a 3% rate is closer to the type of risk-free interest rates currently available.

[7] As shown in ComEd's response in Docket 05-0159 to Staff data request PL 2.08, Attachment 1, 23% is derived from the measured daily volatility of NI Hub 5x16 Electric Forward Price Quotes (7/1/03 - 12/29/04) from Megawatt Daily (2/8/05).



Q. Are there any drawbacks to the option analysis discussed above?

A. Yes. First, the option analysis assumes that the option holder can freely switch between bundled and unbundled service. However, I suspect that there will continue to be significant transaction costs and other factors that deter customers from freely switching back and forth between Company supply and RES supply whenever it is otherwise to their advantage. To put this in terms of the option pricing analysis, customers cannot necessarily be expected to exercise their options optimally. For example, some customers may fail to exercise their option; instead they remain on or switch to RES supply, even when they would be better off on Company supply. More significantly, though, for a customer already on Company supply (at any given moment), the option to take Company supply is exercised ***automatically***, even when it is “out of the money” (i.e., even when the customer should be switching to RES supply and letting the option expire worthless). Such deviations from optimal exercise could be due to other costs of shopping and/or switching that are not taken into account by the option pricing model. In any event, potential suppliers in the auction are apt to be somewhat cognizant of such factors, so the anticipated deviation from optimal exercise should lead to a lower premium for the more distant years of the contract than are implied by the option pricing model.

Second, the contract between the utility and a tranche supplier is not really an option contract (at least not like the option contract modeled), in that the utility has no direct control over buying more or less energy when short-run market prices fall or rise relative to the contract price. Retail customers decide whether to switch between Company supply and RES supply. There is no direct option contract between retail customers and suppliers.

Third, because the utility is annually re-blending together 2-year old, 1-year old, and 0-year old 3-year supplier contracts in order to offer a blended contract to ratepayers, the implicit option strike price seen by ratepayers does not remain fixed from year to year. Thus, the standard option pricing model, discussed above, is not particularly well-suited to valuing the type of risk premium associated with the supply contracts in question. The exercise of an option depends on its strike price, just as the choice to remain on bundled service depends on the price of the blended product. While the option pricing model used above assumes a constant strike price for the entire period, the price of the blended product changes every year as new contracts are added and old ones are subtracted from the blend.

Fourth, the option pricing model used above assumes a constant quantity which is either bought or not bought when the option is exercised or not exercised, respectively. However, in the case of the long-term supply contracts under Ameren's proposal, the quantity depends on when, and how often, if at all, customers decide to exercise the implicit option. For example, suppose a customer begins by taking RES supply, and decides to "exercise the option" to take bundled service within what happens to be year two of a particular 3-year supply contract. To that supplier the quantity from that customer is at most about one-third the total quantity that the customer could have demanded, had the customer exercised the option at every opportunity throughout the entire three years (basically once a year for three years). Also note that, while the change in quantity is spread among all suppliers with time left on their supply contracts with the utility, the firms at greatest risk are those with the most time left on their contracts and the highest differentials between their contract prices and current market prices.

Q. Have you attempted to take the above factors into account to recompute an expected premium for long-term contracts?

A. Yes. However, rather than use an option pricing model, I computed the expected loss of income that the average supplier of 3-, 4-, and 5-year contracts would face, due to the ability of customers to switch within the term of the contract. A premium was added to the contract price to make up for that difference. The logic of this alternative approach is that the supplier is assumed to be able to freely choose to sell either a relatively fixed quantity in the market (without the "optionality" component implicit in the proposed vertical tranche contract) or a vertical tranche contract to Ameren (with the premium). The premium is modeled to rise up to the level needed to equate the value of these two types of contracts.

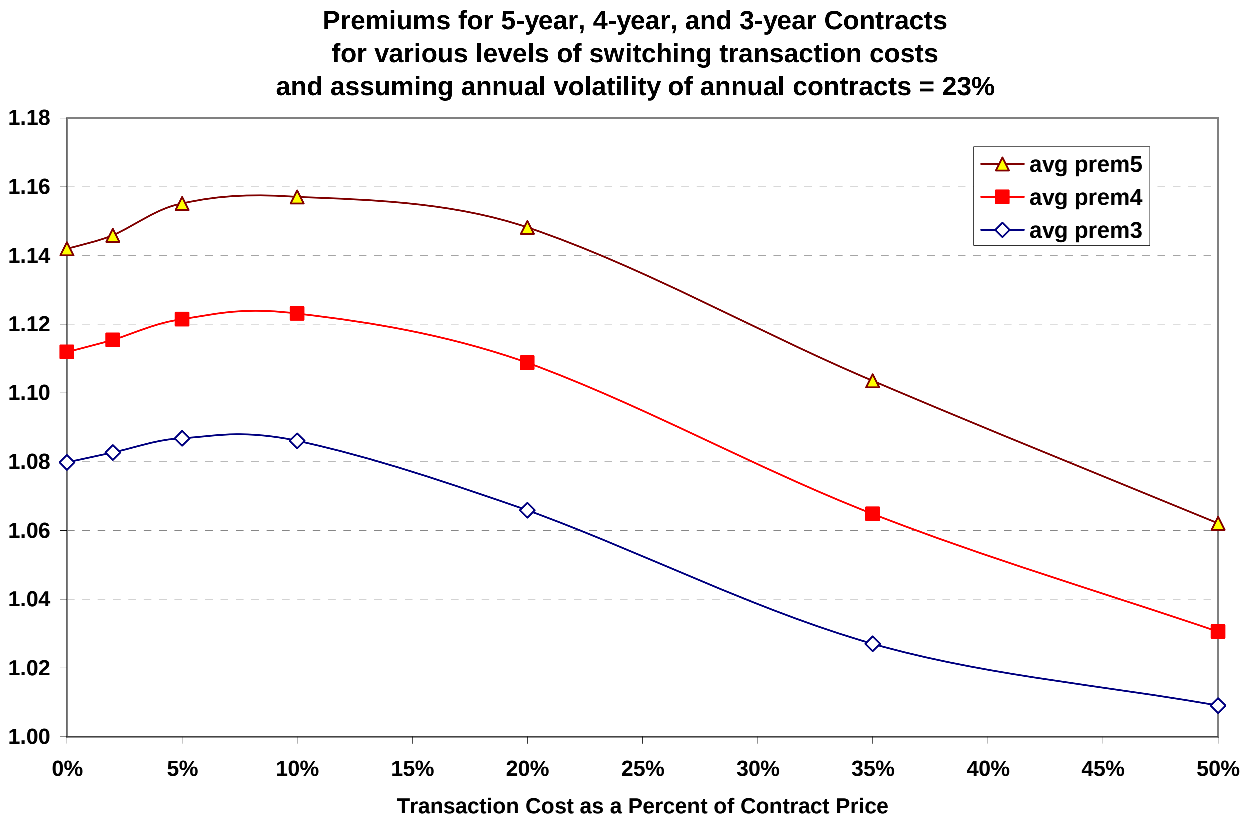
In this alternative analysis, I continued to use the same probabilistic assumptions that were used in the option analysis about how prices change. Using a random number generator, prices were allowed to move according to these assumptions for 500 time periods. I also assumed that the price seen by the ratepayer is a rolling average of the last three 3-year contract prices, with the above-mentioned risk premium. Separately, I performed the same calculations with 4-year contracts and 5-year contracts, even though Ameren is only proposing to use 3-year contracts.

Switching off of bundled service was modeled to occur whenever fixed-quantity contract prices (without the “optionality” premium) were lower than the bundled service rolling average rate (with the “optionality” premium) plus a transaction cost (computed as an assumed percent of the fixed-quantity contract prices). The assumed transaction cost percentage was subjected to a sensitivity analysis where it varied between 0% and 50% (specifically, 0%, 2%, 5%, 10%, 20%, 35%, and 50%). An alternative interpretation of the transaction cost percentage is that it could represent the degree of reluctance to leave bundled service or brand loyalty to the utility. When switching off of bundled service occurred, it occurred for five years (when computing the 5-year contract premium), four years (when computing the 4-year contract premium), or three years (when computing the 3-year contract premium). At the end of that period, customers would again go back to evaluating whether they should switch back or stay off bundled service, using the same price comparison process described above.

For each set of assumptions, the risk premium associated with the 3-, 4-, and 5-year contracts, respectively, was computed as the ratio of (a) the average price paid to suppliers if there was switching taking place (as described above) to (b) the average price paid to suppliers if there was NO switching taking place. The entire process, described above, was repeated 500 times (i.e., with 500 new sets of 500 randomly generated prices) in order to collect an average, as well as a minimum, a maximum and a standard deviation of the risk premiums. These measures were used to determine how consistent the results would be from one random draw to the next.

Q. What are the results from this alternative analysis?

A. The average risk premiums associated with each of the 3-year, 4-year, and 5-year contracts, and for each of the assumed levels of switching transaction costs, are shown in the chart and table, below.



TC	avg prem3	avg prem4	avg prem5
0%	1.080	1.112	1.142
2%	1.083	1.115	1.146
5%	1.087	1.121	1.155
10%	1.086	1.123	1.157
20%	1.066	1.109	1.148
35%	1.027	1.065	1.104
50%	1.009	1.031	1.062

A value of one would imply no risk premium. The extent to which the value exceeds one is the risk premium percentage. For example, the upper right-hand side of the table shows a value of 1.142. This indicates that, for the 5-year contract and the 0% switching transaction cost (TC) level, the risk premium relative to a 1-year contract is 14.2 percent. In general, the results show that the longer-term contracts have larger risk premiums. This relationship holds under each of the switching transaction cost assumptions.

Also, as shown in the graph, above, beyond a certain level of switching transaction costs, the premiums appear to be inversely related to switching transaction costs. For instance, for the 5-year contracts, the average premiums fall from a high point of about 16% to about 6%, as switching transaction costs are assumed to rise from 10% to 50%. A very similar pattern is seen for the 3-year and 4-year contracts.

Q. What do you conclude from your alternative analysis?

A. As with the option analysis, I conclude from my alternative analysis that there is a basis for concern about using long-run contracts, because longer terms can be expected to include higher risk premiums. The analysis justifies a cautious use of long-term contracts. Unfortunately, assessing the actual risk premium that can be expected is not an easy task. As noted earlier, my analysis is not an attempt to forecast the level of risk premiums that will be embedded in long-term contracts purchased through the proposed auction. Rather, it is my attempt to explain the basis for my concern about these contracts.

Q. Does your analysis take into account any expected upward or downward trend in forward prices?

A. No. Both the option analysis and the alternative analysis, above, assume a zero trend in forward prices.

Q. Would an upward trend in electricity prices affect the price paid for long-term contracts?

A. Yes. An upward trend in electricity prices would be embedded in any long-term contracts resulting from the auction. In other words, customers would not be able to escape expected increases in market prices through longer-term contracts. For a guaranteed fixed sales volume, offering a fixed price for the entirety of a long-term contract (such as five years) implies that the early years would be overpriced and the late years would be underpriced, but, on average, over the entire five years, the price would equal the supplier's expected opportunity cost in the market.

Q. How would trends in market prices affect switching risk?

A. As already noted, retail customers served by the blended auction product are free to switch between Company supply and RES supply, at any time. Hence, a long-term fixed price scheme in a market where prices are expected to be getting higher can be expected to induce switching off of Company supply for the initial years of the post 2006 period (when the long-term fixed price has to be above any short-term market price). The increased risk of losing sales in those initial otherwise profitable years of the first long-term supply contracts should lead to a further increase in the price of those contracts. The switching problem is prolonged if the expected upward trend (embedded in the long-run contract price) does not materialize in the ensuing years.

Q. Given your analysis above, why don't you object to the Company's proposal to use 3-year contracts?

A. First, while I am concerned about the potential risk premiums associated with using long-term contracts, I have not provided what I would consider to be reliable predictions of those premiums. Second, in the 2004 NJ auction, both 1-year and 3-year contracts were auctioned simultaneously, and the actual differences in prices between the 1-year and the 3-year products were less than one percent for three of the utilities and 2.87% for the remaining utility. Third, in the first auction, only 33% of demand will be served from 3-year contracts, allowing a comparison with 2-year and 1-year contract prices. Fourth, to the extent to which ratepayers and the Commission may be adverse to price volatility, including long-term contracts in the blend should reduce exposure to such volatility.

Finally, it is worth remembering that the use of 3-year durations is not being written in stone. There will be opportunities to periodically review the auction results and reassess the mix of contracts to be procured in future years. Thus, for the time being, Staff recommends that the Commission accept the Company's proposed use of 3-year contracts, and that the Commission reassess the benefits and costs of using this contract duration at points in the future.

VI. Regrouping of 400 kW to 1 MW Customers

Q. According to CES witness O'Connor,

> **The Coalition recommends that the BGS-FP customer grouping should be bifurcated at the 400 kW level. Larger business customers within the 400 kW to 1 MW demand group would be separated from all those below that level and offered a one-year, fixed price product akin to that offered to customers over 1 MW in demand, that we can call "BGS-LFP2." However, that product would be an automatic default product for customers with less than 1 MW in demand, not requiring an affirmative election.**
>
> **Under this approach, the small customer grouping, residential and smaller commercial retail customers with peak demands up to 400 kW, would continue to be offered the one-year, fixed-price product based on the blended multi-year, laddered auction product.[8]**

[8] CES Exhibit 1.0, pp. 13-14, lines 289-300

Does Staff have a position with respect to this proposal by CES witness O'Connor?

A. Yes. In principle, Staff supports this proposal. As explained in the previous section of my rebuttal testimony, I am concerned that long-term supply contracts, combined with giving customers relative freedom to switch between RES supply and auction-derived Company supply, will lead to significant risk premiums being built into auction prices. It is reasonable to believe that switching in order to take advantage of price changes will be most pronounced for the largest customers in the BGS-FP customer segment (i.e., those within the 400 kW to 1 MW sub-group). According to Ameren witness Blessing, "switching risk is greater for larger customers than for smaller customers." (Resp. Ex. 11.0 (Revised), p. 26, lines 571-572)

Removing the 400 kW to 1 MW customers from the BGS-FP segment--and placing them in their own segment to be served with one-year contracts--would allow the market to decide directly what the switching risk premium for the 400 kW to 1 MW sub-group should be, thus bypassing the issue of whether to perform a computational allocation of the risk premium facing the entire BGS-FP segment. In addition, since the 400 kW to 1 MW sub-group seems to comprise the customers with the highest propensity to switch to delivery services, segregating them from the BGS-FP segment can be expected to reduce the switching risk premium embedded in the auction prices of the revised BGS-FP segment, thus lowering the rate for the smaller customers. In fact, the total amount of switching-risk premiums paid to suppliers should also decrease since the new 400 kW to 1 MW segment would be served with only 1-year contracts rather than the longer-term contracts that I have argued lead to higher risk premiums.

Q. How has the Company responded to this proposal?

A. Ameren witness Blessing argues that the Company should not be too aggressive about tailoring retail power and energy services to various customer classes (Resp. Ex. 11.0 (Revised), pp. 21-23), opining,

> [T]he Ameren Companies should behave in a manner consistent with their role as wires companies and not as companies offering a variety of retail generation products to meet specific end use customer needs. … The Ameren Companies, as IDCs, should not be competing with ARES.[9]

Ameren witness Cooper raises a more practical concern, claiming that 90% of the customers in the 400 kW to 1 MW size range do not have the interval meters that would be necessary for them to be carved out of the BGS-FP segment. (Resp. Ex. 15.0, pp. 18-21)

Q. Do you have a position with respect to Mr. Blessing's argument?

A. While I agree that policy and rate structures should be designed to allow competitive forces to take hold in Illinois retail electric markets, utilities should not be purposefully pricing themselves out of the retail market (for example, by offering poorly-designed products). If there are valid reasons to expect that placing 400 kW to 1 MW customers in the BGS-FP segment (to be served with relatively long-term-contracts) will raise rates for all customers in that segment, such product design can be inconsistent with the Company's obligation to provide least-cost service.

Q. Do you have a position with respect to Mr. Cooper's argument?

A. I would agree with Mr. Cooper that CES witness O'Connor's proposal to segregate the 400 kW to 1 MW customers presents a practical problem if these customers do not have interval metering. Hence, I recommend that Dr. O'Connor's proposal be placed in abeyance pending review of one or more rounds of auction results and subsequent switching activity by customers within the BGS-FP segment. Meanwhile, I would request that the Company present estimates in its surrebuttal testimony of how quickly the Company could install interval meters on customers within the 400 kW to 1 MW size range, as well as the cost of such installation.

VII. Renewable Resource and Energy Efficiency Procurement

Q. CUB/CCSAO witness Steinhurst discusses the procurement of electricity from renewable resources and the procurement of energy efficiency resources. (CUB-CCSAO Exhibit 2.0, pp. 32-39) What does he propose?

A. Basically, he says that these resources could be procured through the Company's proposed auction, but that he prefers that they be procured apart from the auction.

Q. Do you concur with his recommendations?

A. I strongly oppose Dr. Steinhurst's less-favored recommendation to make renewable and energy efficiency purchases through the auction. If such resources are to be procured, I concur that such procurement should be

[9] Resp. Ex. 11.0 (Revised), p. 22, lines 497-503

accomplished outside of the auction. Indeed, the Commission has recently issued a resolution adopting a policy of encouraging voluntary participation by electric public utilities in a plan to make greater use of renewable and energy efficiency resources.[10] Thus, other than rejecting the concepts of making earmarked purchases of renewable energy through the auction and purchases of energy efficiency resources through the auction, it is totally unnecessary for the Commission to make any decisions about purchasing renewable and energy efficiency resources in this docket.

Q. Why do you oppose making special earmarked purchases of renewable energy through the auction?

A. There are no artificial barriers preventing renewable power developers from participating in the auction. The only barriers that may exist are due to the lack of expected profitability of renewable power at market prices. If renewable power production is generally more expensive than conventional power production, I would not be surprised if suppliers' intent on relying on renewable power would be reluctant to compete head-to-head in the auction. However, this should not be remedied with special treatment or set-asides for renewable power within the auction. The end result of such special treatment can only be price increases, especially in the initial post-2006 period, when ratepayers already may be subject to significant price increases due to the end of the price freeze currently in effect for bundled customers.

[10] Resolution, ICC Docket No. 05-0437, July 19, 2005. Available from the ICC's internet-based eDocket system: http://eweb.icc.state.il.us/e-docket/ .

Q. Why do you oppose making special purchases of energy efficiency through the auction?

A. The concept of ***energy efficiency resources*** is fundamentally different than the concept of ***a supply of energy that is meeting vertical tranches of load***. First, there is the problem of measuring <u>reductions</u> in load, which is intrinsically speculative and imprecise, particularly when compared to the exact science of measuring a <u>supply</u> of electricity. Second, even if such measurement problems could be adequately solved, it would be simply impossible to "supply" a vertical tranche of energy efficiency (which presumably would be a constant portion of load in every hour of the year that has been reduced). Hence, the provision of energy efficiency resources cannot be adequately compared against the supply of vertical tranches in a manner that would enable them both to be treated interchangeably in the same auction.

VIII. <u>Role of the Commission Staff</u>

Q. In his rebuttal testimony, Ameren witness Nelson states,

> **As initially proposed, the Auction Manager and the Auction Advisor were to prepare their report on the auction and submit them directly to the ICC. As modified, the Auction Manager and the ICC Staff will submit their reports to the ICC. This allows the ICC Staff more of a direct role in the process.** [11]

Ameren witness Blessing also states,

> **To properly monitor, report, and perform other activities relative to the auction review, the responsible party should have: (a) a deep and broad experience in Illinois and expertise with Illinois-specific issues – for example, administration of the Public Utilities Act; and (b) technical auction experience. The ICC Staff has the necessary**

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[11] Resp. Ex. 10.0, p. 18, lines 396-399

> **Illinois background and is best suited to bring together the technical knowledge of the Auction Advisor and other technical experts. Based on its reconsideration of these factors, the Ameren Companies now believe that the Illinois consumers will be best protected by the ICC Staff taking a principal role in the auction review.**[12]

Does the Staff concur with the Company's proposal for Staff's role in the auction process?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

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[12] Resp. Ex. 11.0 (Revised), p. 54, lines 1196-1204