Ameren Exhibit 2.0

ILLINOIS COMMERCE COMMISSION

DOCKET NO. _______________________

DIRECT TESTIMONY

OF

JAMES C. BLESSING

Submitted On Behalf

Of

CENTRAL ILLINOIS LIGHT COMPANY d/b/a AMERENCILCO

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AMERENCIPS

ILLINOIS POWER COMPANY d/b/a AMERENIP

(THE AMEREN ILLINOIS UTILITIES)

OCTOBER 26, 2007

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DIRECT TESTIMONY

OF

JAMES C. BLESSING

Q. Please state your name and business address.

A. My name is James C. Blessing. My business address is 1901 Chouteau Avenue, St. Louis, Missouri, 63103.

Q. By whom are you employed and in what capacity?

A. I am employed by Ameren Services Company as Manager, Power Supply Acquisition.

Q. Please describe your education and work experience.

A. My education and work background is provided for in Appendix A to my testimony.

Q. Have you previously testified before the Illinois Commerce Commission (the "Commission", "ICC")?

A. Yes. I previously testified in ICC Docket Nos. 05-0160 (cons.) and ICC Docket No. 06-0800.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to introduce and provide an overview of the Ameren Illinois Utilities (the "Utilities") procurement plan document and describe how it complies with the requirement of the law. In addition, I will discuss the Utilities selection of Levitan & Associates, Inc. to act as the procurement administrator on their behalf.

PROCUREMENT PLAN DOCUMENT

Q. What is the procurement plan?

A. The procurement plan is a document that analyzes the projected supply and demand for the Utilities' eligible retail customers over a five-year period starting June 1, 2008. It also identifies the specific wholesale purchases that the Utilities will procure following approval of the plan by the Illinois Commerce Commission. The required content of the procurement plan is specified in Section 16-111.5 (b) of the Public Utilities Act ("PUA"). This particular procurement plan is being filed in accordance with Section 16-111.5(j), which statute incorporates by reference Section 16-111.5(b). The plan is attached to my testimony as Ameren Exhibit 2.1.

Q. Please provide an overview of the Utilities procurement plan document.

A. The Utilities procurement plan document consists of the four primary sections as follows.

I. Introduction and Overview

II. Load Forecast

III. Portfolio Design

IV. Procurement Administrator

The introduction and overview section provides a brief description of the Illinois Power Agency Act and certain modifications to the PUA that were signed into law by Governor Rod Blagojevich on August 28, 2007, including a one time obligation of the Utilities to acquire power supply resources for the June 1, 2008 through May 31 2009 planning period pursuant to Section 16-111.5(j). The load forecast section discusses the process used to develop the five-year peak demand and energy forecast of the eligible retail customer load. The portfolio design section describes the process utilized by the Utilities in arriving at the portfolio of energy, capacity and renewable energy resources that will be procured for the June 1, 2008 through May 31, 2009 planning period. Finally, the procurement administrator section identifies the firm the Utilities have hired to act as the procurement administrator to complete the final design and implementation of the procurement process.

Q. Section III.D(1) of the Utilities procurement plan shows the list of standard energy products that will be procured as part of the request for proposal process. Is that correct?

A. Yes.

Q. How did the Utilities arrive at this portfolio of energy products?

A. As discussed in greater detail in the procurement plan, the Utilities utilized a simulation model populated with 250 scenarios of hourly load and hourly market prices to test various supply portfolios. This analysis attempts to answer the key question of "how much of the energy supply should be hedged with forward contracts and how much should be subject to the MISO spot market prices." The resulting portfolio should strike an appropriate balance between two competing objectives: 1) minimizing the overall expected cost to serve the eligible retail customer load and 2) minimizing the volatility of that expected cost.

Q. Please provide an overview of this analysis.

A. The analysis was completed in two phases. In the initial phase, the objective was to gain an understanding how hedging with forward contracts affects the expected energy cost to serve the load and also how hedging with forward contracts affects the volatility of that expected energy cost. The objective of the second phase of analysis was to arrive at the specific standard market products that will be procured in the procurement process.

Q. Please describe how the first objective was reached.

A. To accomplish this objective, the analysis of how much to hedge with forward contracts for the 12 month period starting June 1, 2008 was broken into 24 independent analyses, one for each of the 12 monthly on-peak periods and one for each of the12 monthly off-peak periods. In each analysis the simulation model tested portfolios ranging from a portfolio that includes no forward contracts (100% of the load priced at the spot market price) to a portfolio of forward contracts in excess of two times the average load in every hour of the period.

Q. What are the results of this initial phase of the analysis?

A. This initial phase of the analysis demonstrated two relationships. First, the results of the simulation model show that adding forward contracts has no impact on the expected cost to serve the load. This result is driven by an assumption in the model that there is no price premium on forward purchases relative to the expected spot market prices. While the Utilities believe there likely is a price premium that exists in the markets, no premium was included in the model because there is insufficient market data to calculate the magnitude of such a premium. As will be discussed later, the Utilities attempted to account for the possible existence of a premium on forwards outside the construct of the simulation model. Second, the results show that the volatility of the expected cost is minimized when the portfolio includes forward contracts at a level close to the average load in each period. This relationship is more pronounced in the on-peak periods as compared to the off-peak periods. Intuitively, it makes sense that the volatility of a portfolio that includes fixed price forward purchases at a level very close to the expected load would be less than a portfolio that includes a greater dependency on variably priced spot market purchases (forward purchases less than expected load), or a portfolio that includes a greater dependency on variably priced spot market sales (forward purchases more than expected load). When considering both of these relationships together, a portfolio that includes forward contracts at a level relatively close to the average load in each period provides the Utilities eligible retail customers price stability with no increase in the expected energy cost to serve the load as compared to a portfolio that does not include forward contracts.

Q. Please describe the second phase of the analysis.

A. As stated previously, the objective of the second phase of the analysis was to arrive at the specific standard market products that will be procured in the procurement process. In doing this, the types of products that are routinely traded in the wholesale market were considered. For example, it is more common to see the months of July and August traded as a combined July-August product, than to see them traded as independent months. The same is true for October, November and December, the product commonly traded is Q4 (fourth quarter). With this in mind, the 24 monthly on-peak and off-peak blocks were consolidated into a smaller number of standard market products. Multiple portfolios of standard market products were developed and tested using the simulation model. The results for each were compared to those of the average load portfolio that was produced in the initial phase of analysis. The comparison showed that consolidating the 24 monthly on-peak and off-peak blocks into a smaller number of standard market products has only a minimal effect on the volatility of the expected cost to serve the load. As a final step, the Utilities attempted to account for the possibility that there is a price premium on forward purchases relative to the expected spot market prices. This was accomplished by looking at how the final portfolio selection might change if it was assumed that the magnitude of this premium is 5.0%. As stated earlier, while the Utilities believe there likely is a premium that exists in the market, the Utilities do not believe that there is sufficient data available to determine the magnitude of the premium. The 5.0% value the Utilities considered is simply a hypothetical scenario that was used in an attempt to account for the likely existence of a premium. The Utilities proposed mix of standard energy products can be found in Section III.D (1) of the procurement plan.

Q. The procurement plan also states the forward contracts that will be utilized to hedge the energy needs will be financial swaps rather than physical transactions. What is a financial swap?

A. A financial swap is a commercial transaction where there is no exchange of physical energy between the parties, and consequently no delivery of that energy to a delivery point. What is exchanged is price risk. In this case, the Utilities are exchanging a price that varies over time (MISO spot market prices) for a fixed price. To illustrate this concept let’s look at the existing 400 MW financial Swap that the Utilities entered into consistent with Section 16-111.5 (k) of the PUA. The terms of that agreement requires, for the period June 1, 2008 through December 31, 2008, the Utilities to pay a fixed price of $47.45/MWh and Ameren Energy Marketing Company ("AEM") to pay the MISO real-time Locational Marginal Price ("LMP") at the Ameren Illinois Utilities Load Zone. The way this agreement will settle is that in every hour during the term, the MISO real-time LMP at the Ameren Illinois Utilities Load Zone will be compared to the $47.45/MWh fixed price. In every hour that the LMP exceeds the fixed price AEM will pay to the Utilities the difference in price times the contract quantity of 400 MW and in every hour that the LMP is less than the fixed price, the Utilities will pay to AEM the difference in price times the contract quantity. So, if the LMP in a specific hour was $60 then AEM would make a payment to the Utilities of $5,020 [($60/MWh - $47.45/MWh) * 400 MW]

Q. If there is no exchange of physical energy between the parties, then how are the energy needs of the load served?

A. The load is served through the MISO day-ahead and real-time energy markets. The financial swap is simply a method of hedging the final price.

Q. You said that the load will be served in the day-ahead and real-time energy markets. What does this mean?

A. The MISO utilizes a centralized security constrained dispatch system to economically dispatch the approximately 127,000 MW of generation within its footprint to serve the MISO footprint load in every hour. In short, the day-ahead market is a forward market, while the real-time market is a balancing market. Any deviation in real-time from the positions cleared day-ahead are settled with MISO at real-time prices. If you cleared generation day ahead and don't generate electricity in real time, you effectively buy back your position at real-time LMP. Similarly, if you cleared load day-ahead, but your forecast was either high or low, you must buy or sell the variance at real-time LMP.

The Utilities will submit a best effort day-ahead forecast to MISO in the form of what MISO calls a demand bid. This results in the quantity of energy for each hour that is contained in the demand bid being cleared in the day-ahead market and priced at the day-ahead energy price. Any difference in the quantities contained in the demand bid and the actual quantities used by our customers will be priced at the real-time energy price and subject to Revenue Sufficiency Guarantee ("RSG") charges.

Q. So let me make sure I have this straight, the energy needs of the load are being served by MISO and the Utilities are paying MISO for that energy at either the day-ahead or real-time price.

A. Yes.

Q. The Utilities are also entering into financial swap contracts with suppliers to hedge the MISO market price risk. Based on this, what is the price that the Utilities pay for their energy they require to serve the customer load?

A. The best way to answer this question is to walk through another example. Let's start with the 400 MW financial swap discussed previously. In that example, the Utilities were exchanging MISO real-time energy prices that vary by hour for a fixed price of $47.45/MWh. And, in that example we considered an hour in which the real-time LMP was $60/MWh which resulted in a $5,020 payment from the supplier to the Utilities. Let's also assume the Utilities submitted a demand bid for that hour of 405 MW and the actual load turned out to be 410 MW in that hour. Finally, assume the day-ahead price for that hour was $61/MWh and the RSG charge was $2/MWh. For that hour the

Utilities would pay MISO $24,705 [405 MW * $61/MWh] for the day-ahead energy and $310 [(410 MW- 405 MW) * ($60/MWh + $2/MWh)] for the real-time energy. In this example, the Utilities will pay MISO a total of $25,015 for this hour but will receive a payment from AEM of $5,020, resulting in a net cost of $19,995 or $48.76/MWh for the 410 MW of energy required to serve the load. This occurs despite the fact that the MISO day-ahead and real-time energy prices were $60/MWh and $61/MWh, respectively.

Q. If your hedge for the load was at $47.45/MWh, then why did the average price end up being more than $1/MWh higher?

A. There are a couple of things happening here that cause the average actual price in this example to be higher than the hedge price. First, the hedge was for 400 MW and the actual load turned out to be 410 MW. This results in the extra 10 MW being priced at the higher MISO energy market prices. Second, the hedge that is in place is linked to the MISO real-time energy prices but in order to minimize exposure to RSG charges, we are serving most of the energy from the MISO day-ahead energy prices. This results in the average actual price reflecting the $1/MWh difference between the MISO day-ahead and real-time prices.

Q. If that is the case, then should the Utilities structure future financial swap contracts so that the Utilities are exchanging the MISO day-ahead energy price for the fixed price instead of the real-time price?

A. Structuring the financial swap with the MISO day-ahead energy price as the floating component would likely create a better hedge for the Utilities if price stability were the only criteria to be considered. But there is a cost to structuring future financial swap contracts in this manner. Transactions that are occurring in the market are dominated by those structured with the MISO real-time price as the float component. Despite this, the Utilities could structure their products using the day-ahead price. But it is likely that in so doing, the product would be less attractive in the market which could result in less competition in the procurement process. In addition, if the day-ahead price was used, it is reasonable to expect suppliers would include in the bid price their best estimate of what that differential will be in the future, along with a risk premium to account for the additional uncertainty this would create. Therefore, the fact that the financial swap settles against the MISO day-ahead energy price rather than the MISO real-time energy price is likely to have little, if any, effect on the final price paid by the end use customer.

Q. Section III.D(1) of the procurement plan also shows how the Utilities will procure the capacity they require to serve the load of their eligible retail customers. Is that correct?

A. Yes.

Q. If the energy is being served from the MISO energy markets, why is capacity required?

A. Capacity is required to ensure reliable service to our customers and is mandated by the Southeastern Electric Reliability Council ("SERC") and MISO. The MISO Open Access Transmission and Energy Markets Tariff ("MISO Tariff") requires market participants who serve load in MISO, to demonstrate that they own or have purchased an amount of capacity equal to their expected peak load plus the appropriate level of planning reserve as set by its regional reliability organization, which for the Utilities is SERC. If the Utilities did not procure capacity to meet this requirement, they would be in violation of the MISO Tariff which is under the jurisdiction of the Federal Energy Regulatory Commission.

Q. This section of the procurement plan shows that the Utilities intend to procure in the RFP process the full 100% of their capacity requirement in the four summer months of June through September but only 90% of the needs in the non-summer months. Please explain the rationale for this.

A. As I said earlier, the Utilities are required to purchase the required capacity to remain in compliance with the MISO Tariff. Because the MISO does not have a formal capacity market at this time, the Utilities will need to procure the capacity in the bi-lateral markets either through a formal RFP process or through a less formal competitive procurement process.

The bi-lateral capacity markets are tightest in the months of June through September when load is at or close to its annual peak. During these summer months, if the load is high as a result of extreme temperatures and demands on the system, and there are more generating units unavailable than expected, it may not be possible to purchase capacity in the market at any price. To ensure the Utilities have sufficient capacity to serve the load during the summer months, the Utilities will procure 100% of their capacity requirement via the RFP process in advance of the summer. In the non-summer months, capacity is generally more plentiful. For this reason, the Utilities will procure only 90% of each month’s capacity requirement via the RFP process. The remaining capacity will be procured on a month-ahead basis using a less formal competitive procurement process as defined in the Procedures for Balancing Loads section of the procurement plan. By procuring only 90% of the requirement in advance and the remaining requirement on a month ahead basis, the chances of over-procuring capacity is minimized. This is important to note because it is unlikely that the Utilities, if faced with an oversupply of capacity, would be successful in finding a buyer for this excess capacity in the non-summer months.

Q. Sections III.E(2) of the procurement plan discuss the products that will be procured to satisfy the renewable portfolio standard included in the Illinois Power Agency Act. Is that correct?

A. Yes

Q. This section of the procurement plan states that the Utilities intend to procure renewable energy credits ("RECs") without the energy associated with those RECs. Please describe the rational for this approach.

A. This approach, to purchase RECs only rather than energy plus the RECs, was selected for the following reasons. First, it is believed a RECs only product will be viewed more favorably by wider range of market participants which should translate into a more competitive procurement process. By procuring a RECs only product, a renewable energy resource who has already committed to sell the energy from their facility to a third party would be able to bid the RECs which they still possess into the Utilities procurement process. Second, to the extent that it would be required to procure renewable energy resources from facilities outside the MISO footprint, purchasing RECs only avoids the added complexity of ensuring that the energy can physically be delivered to the load, which would require the seller to arrange for firm point-to-point transmission service from the facility to the MISO border. Finally, by purchasing the RECs only, the Utilities do not take on the added risk that can be associated with the purchase of energy from a renewable energy resource. For example, if the Utilities were to purchase energy from a wind resource, the Utilities would need to find a way to forecast the amount of energy that the facility would deliver in each hour and factor that into the day-ahead demand bids the Utilities submit to MISO each day. To the extent that the renewable energy forecast was incorrect, this forecast error could result in a larger portion of the Utilities energy needs being served in the MISO real-time markets, which would result in an increase in MISO RSG charges.

Q. Does the procurement plan discuss how bids received in the RFP process, which could be from a wide range of renewable technologies and from both Illinois and non-Illinois renewable energy resources, will be evaluated?

A. Yes, it does. Section 1-75(c) of the Illinois Power Agency Act ("IPA Act") lays out three general criteria that should be considered when evaluating the bids received. First, the renewable energy resources procured need to be cost-effective as defined in the IPA Act. Second, to the extent available, at least 75% of the renewable energy resources should come from wind generation. Finally, through June 1, 2011, renewable energy resources should be procured, to the extent available, from facilities located within the state of Illinois and that purchases from facilities located outside the state may only be used to satisfy the requirement to the extent that in-state resources are not available. The evaluation criteria included in the plan conform to these three requirements.

Q. Does the procurement plan comply with the requirement of the IPA Act?

A. Yes, the procurement plan conforms in all material respects with regard to those requirements laid out in Section 16-111.5(b) of the PUA.

PROCUREMENT ADMINISTRATOR

Q. Section IV of the procurement plan discusses the Utilities selection of Levitan & Associates, Inc. to act as the procurement administrator. Is that correct?

A. Yes.

Q. Please describe the selection process used by the Utilities to select Levitan & Associates, Inc. as their Procurement Administrator.

A. Section 16-111.5 (j) of the PUA requires the Utilities to file, as part of their procurement plan, the identity of their proposed procurement administrator, who shall have the same experience and expertise as is required of a procurement administrator hired pursuant to Section 1-75 of the IPA Act. Section 1-75 (a) (2), of IPA Act defines those requirements. The Utilities developed an RFP for consulting services to act as the procurement administrator for the Utilities and issued it to 12 potential candidates on August 17, 2007. Of the 12 candidates, five submitted bids to the RFP on or before the due date. These five bids were evaluated using the matrix included in Section IV.C of the procurement plan and the Utilities subsequently selected and hired Levitan and Associates, Inc. ("Levitan") to act as their procurement administrator.

Q. Does Levitan meet all the requirements included in Section 1-75 of the IPA Act?

A. The Utilities believe Levitan does meet those requirements and is capable of performing the duties of the procurement administrator. The Levitan team has in excess of 20 years of relevant experience including experience with large scale competitive procurement processes for the Connecticut Department of Public Utility Control and the Long Island Power Authority. Members of the Levitan team assigned to this project have advanced degrees in economics, energy economics, engineering, finance and geological sciences. A complete list of Levitan's qualifications can be found in their RFP bid which is included as Appendix C of the procurement plan.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX A

EDUCATION AND WORK EXPERIENCE OF JAMES C. BLESSING

My educational background consists of a Bachelor of Science degree in Electrical Engineering from the University of Missouri-Rolla in 1988 and a Masters in Business Administration degree from St. Louis University in 1998. My work experience started as an Electrical Project Engineer for Southern Indiana Gas & Electric Company in October of 1988. In 1992, I accepted a position with the Power Generation Services Division of General Electric Company as a Field Engineer. In 1994, I left General Electric Company to accept a position with Union Electric Company as a Plant Engineer at the Labadie Power Plant. In 1999, I transferred to Ameren Services ' Corporate Planning Department where I held the position of Consulting Planning Engineer. On January 1, 2004, I was promoted to the position Director of Resource Acquisition. On October 15, 2004, my position was transferred to the Strategic Initiatives Department and my title was changed to Managing Supervisor, Power Supply Acquisition. On April 1, 2007, I was promoted to my current position of Manager, Power Supply Acquisition. The duties of my current position consist of procuring power supplies for Ameren Corporation's regulated utilities in Illinois and administering the contracts that result.