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Kansas Corporation Commission
/S/ Susan K. Duffy

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STATE CORPORATION COMMISSION
JAN 31 2006
Docket Room

BEFORE THE STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

BURTON L. CRAWFORD

ON BEHALF OF KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF KANSAS CITY POWER & LIGHT COMPANY TO MODIFY ITS TARIFFS TO BEGIN THE IMPLEMENTATION OF ITS REGULATORY PLAN

DOCKET NO. 06-KCPE-828-RTS

Q: Please state your name and business address.

A: My name is Burton L. Crawford. My business address is 1201 Walnut, Kansas City, Missouri 64106-2124.

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

A: I am employed by Kansas City Power & Light Company ("KCPL") as Manager, Energy Resource Management.

Q: What are your responsibilities?

A: I am responsible for managing the Energy Resource Management ("ERM") department. Activities of ERM include resource planning, wholesale energy purchase and sales evaluations, energy portfolio management, and capital project evaluations.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration from Rockhurst College and a Bachelor of Science in Mechanical Engineering from the University of Missouri. Within KCPL, I have served in various areas including regulatory, economic research, and power engineering starting in 1988.

Q: Have you previously testified in a proceeding at the Kansas Corporation Commission ("KCC") or before any other utility regulatory agency?

A: Yes, I have. I provided testimony to the Missouri Public Service Commission ("MPSC") in Case No. EO-2006-0142, which pertains to KCPL's application to join the Southwest Power Pool Regional Transmission Organization.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the significant supply-related projects KCPL has undertaken since its last filed rate case. Please note that the direct testimony of KPCL witness F. Dana Crawford provides a description of these projects and confirms that each project satisfies the applicable in-service criteria. I will also describe the level of fuel expense and purchase power expense filed in the Cost of Service. I will also describe KCPL's recent review of its resource plan in light of significant changes in natural gas prices and other factors that can impact KCPL's expansion plan.

I. Prudence of Significant Supply-Related Projects

Hawthorn Unit 6

Q: Please describe the need for Hawthorn Unit 6.

A: In 1994, when the opportunity to purchase Hawthorn Unit 6 developed, it was anticipated that KCPL would need additional peaking capacity of 272 MW in the year 2000.

Q: Did KCPL investigate alternatives for meeting these needs?

A: Yes, it did. At that time, KCPL modeled three alternatives: installation of a combustion turbine in 2000 (per KCPLAN 94); the Siemens combustion turbine in 1997; and a purchase power contract with a power marketer that had approached KCPL with an offer. The net present value of revenue requirement ("NPVRR") was calculated for each alternative over a 30-year period.

Q: What were the results of the NPVRR calculations?

A: The Siemens combustion turbine alternative provided a NPVRR savings of $14.6 million compared to the combustion turbine in 2000. These savings came from the significant reduction in price offered by Siemens that offset the additional cost of committing to the resource earlier than required. The NPVRR calculation also indicated that the Siemens combustion turbine alternative had about a $4 million savings over the contract with a power marketer.

Q: Why did Siemens offer a significant price reduction to KCPL?

A: This combustion turbine was Siemens' first in the large advanced combustion turbine category and was offered at a reduced price. The offer was about 60% less than what KCPL had anticipated in its planning process.

<u>Hawthorn Units 7, 8 and 9</u>

Q: Please describe the need for Hawthorn Units 7, 8, and 9.

A: In 1998, KCPL's load was expected to grow at an annualized rate of approximately 2% over the 1997-2007 timeframe. At the time, this equated to approximately 65 MW of additional capacity each year in order to meet KCPL's required capacity margin. In 1997 and 1998, the MOKAN capacity margin requirement was 13%. It was anticipated that KCPL would be under the Southwest Power Pool in 1999 with a reduced capacity margin of 12%. Based on a 12% capacity margin, KCPL was anticipated to have a 120 MW shortfall in the year 2000. In addition to this shortfall, KCPL risked losing its steam purchase contract with Trigen for steam supplied to KCPL's Grand Avenue turbines with a capacity of 73 MW. In addition, KCPL's Needs Assessment completed in March 1998 supported the need for additional peaking capacity.

Q: Did KCPL investigate alternatives for meeting these needs?

A: Yes, it did. As part of the Needs Assessment completed in 1998, KCPL investigated combinations of coal-fired plants, combustion turbines and combined-cycle plants. These alternatives were evaluated based on the NPVRR. It was determined that combustion turbines were the least cost option in the near future.

In addition to investigating physical ownership alternatives, KCPL conducted several surveys on the possibility of contracting for capacity and energy in the 2000-2005 timeframe. This approach was taken instead of the issuance of formal requests for proposals ("RFPs") because of information KCPL received from other utilities that had issued RFPs. RFPs issued by other utilities had produced limited responses and the responses they did get were subject to prior sale and further negotiations.

Surveys were sent to utilities interconnected with KCPL, non-interconnected utilities and power marketers. Each survey was structured to assess the available capacity for sale. The results indicated that the majority of interconnected utilities were projected to be capacity deficient in the 2000-2005 timeframe and were looking to either purchase capacity, install new capacity, or looking to partner for installed capacity. Two entities expressed interest in partnering with KCPL on a combined-cycle facility.

Of the many power marketers contacted, many chose not to respond due to market volatility and transmission capacity uncertainty; some expressed interest in non-firm contracts.

Q: Which combustion turbine supplier did KCPL choose for Hawthorn Units 7 & 8 and why?

A: KCPL selected General Electric ("GE") over other proposals due to schedule, installed price, and reliability considerations.

Bids were received from Siemens, Westinghouse and GE. The installed price per kW of capacity was lowest for the GE units. In addition, there was significantly more operating experience with the GE units. GE had over 500 of the EA class units in service with a reliability of 99%.

Q: If KCPL's need was for peaking capacity, why did KCPL build a combined-cycle unit by installing a heat recovery steam generator ("HRSG") and repowering Hawthorn Unit 4, which had been in storage, as Hawthorn Unit 9?

A: While the immediate need was for peaking capacity, adding the HRSG and repowering Unit 4 gave KCPL the efficiency of a combined-cycle unit, but at a cost comparable to a simple-cycle combustion turbine because existing assets at Hawthorn could be utilized.

<u>**Hawthorn Unit 5**</u>

Q: What was the process undertaken to evaluate rebuilding Hawthorn 5 following the boiler explosion in February 1999?

A: The Company determined that the lost generating capacity needed to be replaced in order to have sufficient capacity to meet its current and future load requirements. Generally, the analysis process looked at the long-term financial impacts on ratepayers of rebuilding the unit compared to the competing, alternative resource options that were commercially viable at the time. Specifically, the Company considered either rebuilding the unit, or replacing the lost capacity with gas-fired combustion turbines or a gas-fired, combined-cycle generating facility. The analysis included the impact of uncertainties such as natural gas prices, load growth, capital costs of the rebuild project, market prices as affected by regional resource additions, and the potential for carbon emissions regulations. This analysis used the MIDAS™ model to develop market prices and to determine the production costs of the various alternatives under each of the various uncertainty scenarios. Bids were obtained to develop the costs of building a new boiler and outside engineering consultants developed cost estimate ranges of the balance-of-plant work for other equipment and work required to complete the rebuild. For the other replacement alternatives, capital cost estimates were based on information from engineering consultants, along with other available sources. The non-fuel operating costs and the capital construction costs of each alternative were added to the net production costs to arrive at a total cost of the alternative. The study determined a capital cost indifference level for the rebuild alternative, under which rebuilding the coal plant would be economically equivalent to each of the other alternatives. This approach recognized the uncertainty regarding the extent of damages to the plant, which would result in uncertainty as to the overall cost of the rebuild project. The indifference point showed the maximum capital cost of the rebuild that could be incurred before the rebuild alternative would not be preferred over the other alternative. This indifference point was then compared to the preliminary capital cost estimate range of the rebuild alternative. If the indifference point was higher than the rebuild cost estimates, the rebuild was the preferred alternative.

Q: What was the result of this analysis?

A: The study showed that the capital cost for the rebuild alternative was significantly lower than the capital cost indifference points of either of the other replacement alternatives, therefore the rebuild alternative was the preferred alternative. In addition, the study showed that the NPVRR of the rebuild alternative was lower than the other alternatives, indicating that it was preferred from a ratepayer perspective.

<u>West Gardner Units 1-4 and Osawatomie Unit 1</u>

Q: Please describe the process employed to evaluate the West Gardner and Osawatomie Units.

A: As with other resource planning processes that KCPL has undertaken, a determination of need was made. This "Needs Assessment" process started with a comparison of KCPL's projected load growth in terms of both capacity and energy. Capacity requirements include the Southwest Power Pool requirements for a 12% capacity margin. Once KCPL established a determination of need, it assessed alternative means of meeting that need.

Q: In the case of the West Gardner and Osawatomie Units, what was the need?

A: During 2000 when these projects were initiated, KCPL's load was forecasted to grow at an annualized rate of approximately 2% per year during the 2001-2005 timeframe. At this growth rate, approximately 80 MW of capacity would be required each year. The Needs Assessments continued to support the findings of the KCPLAN 94 that peaking capacity was needed.

Based on load forecasts at that time, KCPL was expected to be deficient of the 12% capacity margin by 136 MW in 2003, 219 MW in 2004, 553 MW in 2005, and 635 MW in 2006.

Q: Did KCPL investigate alternatives for meeting these needs?

A: Yes, it did. In the years just prior to construction of the West Gardner and Osawatomie Units, KCPL had been able to meet its annual capacity needs through capacity purchases from other utilities. It had been part of KCPL's strategy to purchase capacity as long as the market could provide capacity that was reliable and more economic than the cost to build. During 2000, KCPL issued an RFP for 250 MW of capacity and associated energy for 2003 through 2008. KCPL received responses from 13 potential suppliers. In all cases, the proposals exceeded the cost for KCPL to develop peaking facilities. KCPL also solicited bids from three major combustion turbine suppliers. These were GE, Alstom and Siemens/Westinghouse.

Q: Which combustion turbine supplier did KCPL choose and why?

A: KCPL selected GE based on price, delivery schedule and proven technology.

Siemens/Westinghouse was rejected due to its inability to meet KCPL's schedule. Its delivery schedule was after the required on-line date to meet KCPL's 2003 needs. In addition, the Siemens/Westinghouse estimated price per kW was higher than GE's price per kW.

Alstom was rejected because it had recently pulled its small heavy frame unit from the market due to problems in meeting NOx guarantees. Alstom's replacement technology had not yet been proven and was therefore rejected.

Q: Were any other alternatives to the West Gardner and Osawatomie Units investigated?

A: Yes, they were. In addition to comparing the cost to purchase capacity versus the cost to install capacity, KCPL considered purchasing capacity for a five-year period and building capacity thereafter.

Q: Please describe the financial analysis of the alternatives.

A: Each alternative was compared on a 20-year NPVRR basis. The 20-year capacity purchase alternative had a 20-year NPVRR that was $35.1 million higher than the combustion turbine installation alternative. The five-year purchase alternative (with subsequent combustion turbine installation) had a 20-year NPVRR that was $26.2 million higher than the combustion turbine installation alternative. From a financial perspective, the installation alternative was superior.

Q: Are there other benefits of building capacity that are not reflected in this financial analysis?

A: Yes. If KCPL installs capacity, we would not incur firm transmission service charges or be as likely to be subject to transmission line loading relief during times of transmission congestion. Other benefits to owning include the ability to dispatch on short notice and ancillary services.

II. Energy Price Forecasts

Q: Could you describe how KCPL forecasts electricity prices?

A: KCPL utilizes the MIDAS™ model, which is similar to other fundamental price forecasting models that are commonly used in the industry. MIDAS™ is provided by Global Energy. The Transact Analyst™ component of MIDAS™ generates regional prices by modeling power flows within and between various energy Markets, Transaction Areas, NERC Sub-Regions, and NERC Regions. Power flows are determined based on the relative loads, resources, marginal costs, transactions costs, and intertie limits between the areas or regions. Transactions occur on an hourly basis for 8760 hours per year.

Q: What are the primary inputs to the model?

A: The model utilizes a sizeable input dataset, referred to as the National Database. It is populated with assumptions about market supply, demand, and transmission. The bulk of the input assumptions use Federal Energy Regulatory Commission ("FERC") Form 1, Energy Information Administration ("EIA") 411 reports, and Continuous Emissions Monitoring system ("CEM") data compiled by the Environmental Protection Agency ("EPA"), as their source. The demand data includes projected hourly demand for virtually every utility in the eastern interconnect. The supply data contains a representation of all generating units within those utilities: capacity, heat rate, fuel type, variable operations and maintenance costs, outage rates, emissions rates, start-up costs, etc. Fuel costs may also be tied to individual units based on reported costs. This applies primarily in the case of nuclear and coal units, whose fuel cost would not be tied to a national commodity price such as is the case with natural gas or fuel oil. The other primary inputs are: natural gas prices, natural gas basis adders, fuel oil prices, and emission allowance prices. These inputs are more "global" in nature, meaning they are not tied to specific units. The dataset also includes transmission constraints between the areas. Global Energy, the provider of the National Database, arrives at the constraints through their analyses of regional assessments from the various reliability councils.

Q: How does the model use this data to forecast power prices?

A: The model performs an hourly chronological dispatch of all generation resources to meet projected hourly demand in each region as defined in the model's geographic topology. For each hour, the last generator needed to meet demand is identified as the marginal unit. All of the costs associated with dispatching the marginal unit become the basis for the price in that hour in that region.

Q: Is this done for only one region?

A: No. Our market simulations model most of the eastern interconnect. As a result, the unit identified as marginal may be dispatched in order to serve load in a neighboring region. The model will perform transactions between regions, as long as adequate transmission capacity still exists. If transmission becomes constrained between regions, before all of the economical transactions have been completed, the model's bidding logic will arrive at an appropriate price spread between the two regions.

Q: How much confidence do you have in the resulting forecasts?

A: The resulting forecast is only as good as the input assumptions. The fundamental supply and demand data are relatively good. That is, the demand forecast from utilities and the existing public data on installed generation capacity are fairly reliable, so identifying a reasonable unit to base an hourly price on is something that can be done with a fair amount of confidence. The input assumption that creates a larger challenge is fuel price. In KCPL's market area, the market price is almost always set by one of two fuels: coal or natural gas. Primarily, it is natural gas. Fuel oil might set the price of power in a very small number of hours in some years in North Southwest Power Pool ("SPP").

Q: How difficult is it to predict the price of coal and natural gas?

A: Coal prices are relatively less volatile and the model inputs are based on actual reported fuel costs, so it is not difficult to predict its impact on power prices when it is the marginal fuel. Natural gas prices are much more difficult to predict, as discussed in the direct testimony of KCPL witness Ed Blunk.

Q: So how accurate are your power price forecasts?

A: The power price forecasts are fairly accurate when the fuel price forecasts are accurate, more specifically, when the natural gas price forecast is accurate. Natural gas is the marginal fuel in North SPP more than 50% of the hours in a year, so there is a strong correlation between natural gas and power in those hours. Schedule BLC-1 presents how closely KCPL's power price forecast tracked prices that we observed in the North SPP market. It is a backcast of 2005 using the average spot gas price for each month. It is worth noting that KCPL uses one gas price for each month of the forecast period. Though in reality, the gas price can change every day. To the extent that gas prices were more volatile, intramonth, that would affect our ability to track actual market prices with our backcast. Schedule BLC-2 illustrates the monthly volatility of natural gas in 2005. In addition to intramonth gas prices, there is another factor that would influence our backcast versus the actual market. The actual hourly demand data for 2005 is not yet available. Our backcast uses the forecasted hourly demand that is part of the National Database I discussed earlier.

III. Purchase Power and Fuel Normalization

Q: What method for normalizing the test year fuel and purchased power expense did you use in this case?

A: The proper method for normalizing the test year fuel and purchased power expense is to normalize and annualize the system peak and energy, the market price of purchased power, the prices paid for fuel, generating system maintenance and forced outages, and available generating resources. After determining the appropriate normalized and annualized values, an accurate production cost computer modeling tool is used to develop the appropriate generation and purchased power levels and resulting fuel and purchased power expenses. KCPL used the MIDAS™ model for its production cost model.

Q: Please describe the MIDAS™ model used in this normalization.

A: This is the same modeling software used to generate the market price forecasts described previously. For purposes of running the production cost modeling used in this normalization, the model was run in "Price Mode", which means the user inputs the market prices into the model, rather than using the model to generate the prices. The prices input into the model were the prices generated by the previously described price forecasting process. The model performs an economic dispatch of the Company's generating units and available market purchases in order to serve load in a least cost manner. The Company uses this model for various purposes, such as generating market price forecasts, long-term resource planning decisions, fuel and interchange budgeting, purchase and sales analysis, and other purposes.

Q: Please describe the normalization of the system requirements for this rate case.

A: KCPL's native load was adjusted to reflect weather normalized and annualized customer growth by the Company's load forecasting personnel. This process is described in more detail in the direct testimony of KCPL witness George M. McCollister. This resulted in revised monthly peak demands and energy requirements, which were input into the

MIDAS™ program. The program distributed the monthly energy requirements on an hourly basis. The software uses the normalized monthly energy and peaks and actual historical hourly system loads, to shape the normalized loads on an hourly basis. The resulting load shape was then used in the normalized production cost modeling case. The Company's firm wholesale commitments have been added to the native load to arrive at the total system requirements.

Q: Please describe these firm wholesale commitments.

A: These are capacity and energy sales to the City Utilities of Springfield, Independence Power and Light, and load regulation customers.

Q: Please describe the fuel price normalization.

A: The normalized fuel prices used in the modeling were developed by Ed Blunk and are described in detail in his direct testimony. These fuel prices were input into the model on a plant-specific basis and then were used in the normalized production cost modeling. The natural gas prices provided by Mr. Blunk were also used in the process of generating market prices.

Q: Please describe the maintenance outages normalization.

A: The Company performs scheduled maintenance on the base load generating units on a cyclical basis over a number of years. That is to say a specific unit in any given year may have an extended turbine generator outage, a shorter boiler outage, a short inspection outage or no outage at all. In addition, Wolf Creek refueling and maintenance outages occur every eighteen months, occurring in either the spring or fall, thus in every third year Wolf Creek is available for generation for the entire year. Thus, in any specific year, there may be higher or lower scheduled maintenance outages than the long term average maintenance outages. In order to normalize the availability of the generating resources for the test year, we computed the total number weeks that a unit would be scheduled out for maintenance over the maintenance cycle and averaged this amount by the number of years in the maintenance cycle. These normalized maintenance outages were then spread over the test year to develop a test year maintenance schedule. These outages were scheduled so that no two units would be out at the same time and that all the base load generating resources would be available during the peak load periods of June through September. This approach resulted in a total amount of generation capability "lost" due to maintenance activities that is approximately equal to the long-term average. Schedule BLC-3 contains the maintenance schedule that was used for the normalization.

Q: Please describe the generating resources available capacity normalization.

A: The generating resources available in the rate case modeling are the same as the Company's existing resources with adjustments made to normalize the capacity to the levels that are expected to be in place and operational as of September 30, 2006. First, long-term purchase power contract levels were adjusted to reflect the capacity levels that are committed effective September 30, 2006. Second, any temporary limitations of generating capacity that currently exist that are expected to be mitigated by that time have been eliminated. Finally, the wind generation that is scheduled to be in commercial operations as of October 1, 2006 has been assumed to be in operations for the full test period.

Q: How was the proposed wind generation modeled in this rate case?

A: The wind generation was modeled based upon the projected output for the site that KCPL has under contract. The actual wind profile data was used to develop projected typical weekly energy output data. This generation was included in the Company's total generation resource mix.

Q: How accurate are the results of this modeling?

A: As a starting point for this modeling effort, we began with the modeling dataset that was used to develop the Company's current fuel and interchange budget. In the budgeting process, results are reviewed to determine if the generation levels, plant performance, and purchased power levels fall within reasonable levels of accuracy based on historical results and current expectations. The modeling assumptions for operating heat rates, equivalent forced outage rates, capacity, and other key inputs are based upon historical averages. Thus, after making the normalization adjustments described previously we believe that the results should likewise result in reasonably accurate results.

Q: For the test period, what expense items, if any, were adjusted as a result of normalizing fuel and purchased power expense?

A: Adjustments were made to the fuel costs to reflect both the normalized fuel market and normalized generation levels. Also, purchased power expense was adjusted to reflect the changes in the quantity of energy purchased and the price of such purchases. Schedule BLC-4 shows the generation levels by resource type and the purchase power levels, the costs of each, and the revenues from the firm wholesale commitments. The adjustments are reflected in the direct testimony of KCPL witness Don A. Frerking.

IV. Off-System Sales Risk

Q: Could you describe KCPL's off-system sales?

A: KCPL makes two general types of off-system sales. First, the sales to firm wholesale customers as previously described, referred to as "Firm" wholesale sales. Second are sales to the open wholesale market, typically on a short-term basis - such as hour-, day-, week- or month-ahead – with prices and terms determined at the time of the sale. These are referred to as "Non-Firm" wholesale sales. The following discussion of risk factors is in connection with only these "Non-Firm" wholesale sales.

Q: Could you describe the risk factors related to KCPL's Cost of Service in connection with the wholesale market?

A: The primary risks are related to the uncertainty around total production, the allocation of that production to retail or wholesale, and the prices received in the wholesale market.

Q: What is the risk related to uncertainty around total production?

A: The uncertainty related to total production is the variability in forced outage rates of the base load units. KCPL has been able to sell virtually every megawatt hour it is capable of generating with its base load fleet. The energy can be used to serve retail load or sold into the wholesale market. But when a unit is forced out of service, no revenue is received from the wholesale market. KCPL owns 2,791 megawatts of base load generating capacity. A 3% variance in the availability of that fleet equates to 733,475 megawatt hours on a twelve-month basis. Using the average wholesale margin of **[redacted]** per MWh that KCPL expects to receive in 2007, the first year rates are in effect, we would experience a **[redacted]** change in wholesale margin.

Q: So KCPL has **[redacted] at risk from unit availability?**

A: No. The very simple example I provided is likely an understatement. For one thing, KCPL has more excess generation available for wholesale sales in the off-peak hours than in the on-peak hours. That is the nature of our retail load profile. This causes KCPL's average wholesale revenues to be weighted toward the off-peak hours. When we lose a unit, we lose those megawatts around the clock. So the value of the megawatt hours lost is closer to the margin received from an around-the-clock market price. That amount varies widely, but is expected to be more than **[redacted]** per MWh in 2007.

Q: So the effect on average margin per MWh could be greater?

A: Yes, in a good case. In a worse case, KCPL could be forced to purchase energy in the wholesale market, at a loss, to continue to serve its retail load obligation with inadequate total resources.

Q: What is the dollar value of that exposure to negative margins?

A: In theory, it is limitless. In reality, KCPL has a few hours in most years that we lose in excess of $100 per MWh serving our retail load obligation. This can occur even without unusual unit outages. I base this statement on historic system lambda data. Historically, KCPL has purchased power at much greater losses, during unusual unit outages. During the extended outage of Hawthorn Unit 5, in 1999, we made purchases at losses of $3,000 to $5,000 per MWh to serve retail load. Hawthorn Unit 5 was forced out of service from February 1999 until June of 2001.

Q: What is the nature of your exposure to the allocation of production to retail load versus wholesale sales?

A: When we achieve expected levels of generation, retail load provides a reliable, consistent margin. That is to say, the rates do not vary. As I mentioned earlier, KCPL has been able to sell virtually every megawatt hour it is capable of generating with its base load units. So to the extent that retail demand varies, that will increase or decrease our exposure to the wholesale market. Margins in the wholesale market are highly volatile. The dynamics of this uncertainty are complex. Depending on market conditions, fluctuations in the level of retail demand could have a positive or negative effect on energy margins, and any combination of positive and negative scenarios could happen during the course of one year.

Q: What is the nature of your exposure to prices received in the wholesale market?

A: That is a considerable uncertainty. Wholesale prices have experienced increased volatility in recent years, driven by gas prices, emissions allowance prices, availability of delivered coal, etc. In the period 2003 – 2005, KCPL has experienced average annual sales prices from wholesale sales ranging from **[redacted]** per MWh. Over the same period, the average wholesale volume was **[redacted]** MWhs. Applying this range of price uncertainty to the average volume yields a revenue uncertainty **[redacted]** wide. This is calculated as **[redacted]**.

Q: What are other uncertainties that create risks to KCPL's Cost of Service in connection with the wholesale market?

A: Yes, there are additional uncertainties that I have not discussed.

Q: What are those additional uncertainties and factors?

A: One factor is what we refer to as quantum unit outages. An example of this would be losing the output of an entire base load unit for a period of months or years. Hawthorn Unit 5 represents 20% of our base load generation. The loss of this unit for an extended period would be a drastically worse scenario than the 3% variance I offered as a **[redacted]** example. Another uncertainty is our ability to obtain sufficient coal deliveries to maintain an expected or significant level of wholesale sales. We could lose most or all of those margins, in spite of the fact that the units were available and market prices were attractive, *e.g.*, the lack of availability of coal such as experienced in 2005 that is expected to continue into 2006.

Factors that could influence the uncertainties I discussed earlier are transmission availability and market structure in SPP. Limited transmission availability would lower our wholesale volumes. A change in the structure of the SPP market could lower the average revenue per MWh for KCPL.

V. Wholesale Margin Projections

Q: What does KCPL project in wholesale margins for 2006 and 2007?

A: The 2006 and 2007 budgets proposed in the late summer and early fall of 2005 project **[redacted]** and **[redacted]**, respectively, for wholesale margins.

Q: What is the source of those projections?

A: KCPL uses the MIDAS™ model to establish the corporate budget for fuel and interchange. Wholesale margins are calculated as: non-firm sales less the cost of non-firm sales. The cost of non-firm sales are calculated as follows.

Cost of non-firm sales = fuel cost * (non-firm generation / total generation)

This calculation is performed for each unit for each month of the budget period.

Q: How is non-firm generation identified?

A: The MIDAS™ model performs an hourly chronological dispatch of KCPL's generation to serve firm load. It will then evaluate the profitability of dispatching the remaining capacity from each generator into the wholesale market. The model captures this information hourly and summarizes it into monthly data.

Q: Is there uncertainty in these wholesale margin projections?

A: Yes. All of the factors I described earlier, related to wholesale sales, create uncertainty in wholesale margins. The uncertainty around projections of wholesale margins is more fully described in the direct testimony of Michael Schnitzer.

VI. KCPL's Resource Plan

Q: Could you describe KCPL's obligation to monitor the Resource Plan under the Stipulation and Agreement concerning KCPL's Regulatory Plan, which the KCC approved in Case No. 04-KCPE-1025-GIE ("Agreement")?

A: In the Regulatory Plan Stipulation and Agreement, KCPL agreed to actively monitor the major factors and circumstances which influence the need for and economics of all elements of its Resource Plan. Such factors and circumstances would include, but not be limited to:

(a) terrorist activity or an act of God;

(b) a material change in federal or state tax laws;

(c) a material change in federal utility laws or regulations or a material change in GAAP;

(d) an unexpected, extended outage or shutdown of a major generating unit(s), other than any major generating unit(s) shut down due to an extended outage at the time of the filing of this Agreement (these units are the major coal burning facilities identified as Hawthorn Unit 5, Iatan Unit 1, LaCygne Units 1 & 2 and Montrose Units 1, 2 & 3, and the nuclear unit Wolf Creek);

(e) a material change in KCPL's load forecast;

(f) material change in the cost and/or reliability of power generation technologies;

(g) material change energy market conditions;

(h) material change in the cost and/or effectiveness of emission control technologies;

(i) material change in the price of emission allowances; and/or

(j) material changes in the projected rates and costs to ratepayers resulting from the Resource Plan.

Q: Has KCPL monitored the major factors and circumstances that influence the need for and economics of the Resource Plan?

A: Yes, it has. All of the factors listed in the previous question have been monitored for significant changes. When there is a significant change to a factor, KCPL will evaluate the impact of that change on the Resource Plan, utilizing the same tools and processes that were used in the original plan.

Q: Have there been changes to any of the factors, since the original Resource Plan?

A: Yes. Gas prices have increased, the Energy Bill extended the production tax credit for wind generation, and the market value of SO_2 allowances has increased and construction costs for new projects have increased based on revised estimates. It should be noted, however, that we have not yet received bids on the major components of those projects that would allow us to refine these estimates.

Q: Is KCPL re-evaluating the Resource Plan based on the changes to these factors?

A: We are in the process of re-evaluating the Resource Plan based on changed factors. The more recent data was incorporated into the evaluation process to determine the reasonableness and adequacy of the Resource Plan. This produced a revised analysis of the expected value associated with the current Resource Plan. To date, changed factors have not impacted the reasonableness and adequacy of the resource plan. Changed factors such as natural gas price increases and extension of the production tax for wind enhance the reasonableness and adequacy of the resource plan.

Q: Do you expect that the changed factors or circumstances will impact the reasonableness and adequacy of the Resource Plan?

A: No. While the NPVRR of the Resource Plan increased, it is still likely the best alternative relative to the other options considered.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City)
Power & Light Company to Modify Its Tariffs to) Docket No. 06-KCPE-____-
Begin the Implementation of Its Regulatory Plan))

AFFIDAVIT OF BURTON L. CRAWFORD

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Burton L. Crawford, being first duly sworn on his oath, states:

1. My name is Burton L. Crawford. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Manager, Energy Resource Management.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of twenty-three (23) pages and Schedules BLC-1 through BLC-4, all of which having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Burton L. Crawford

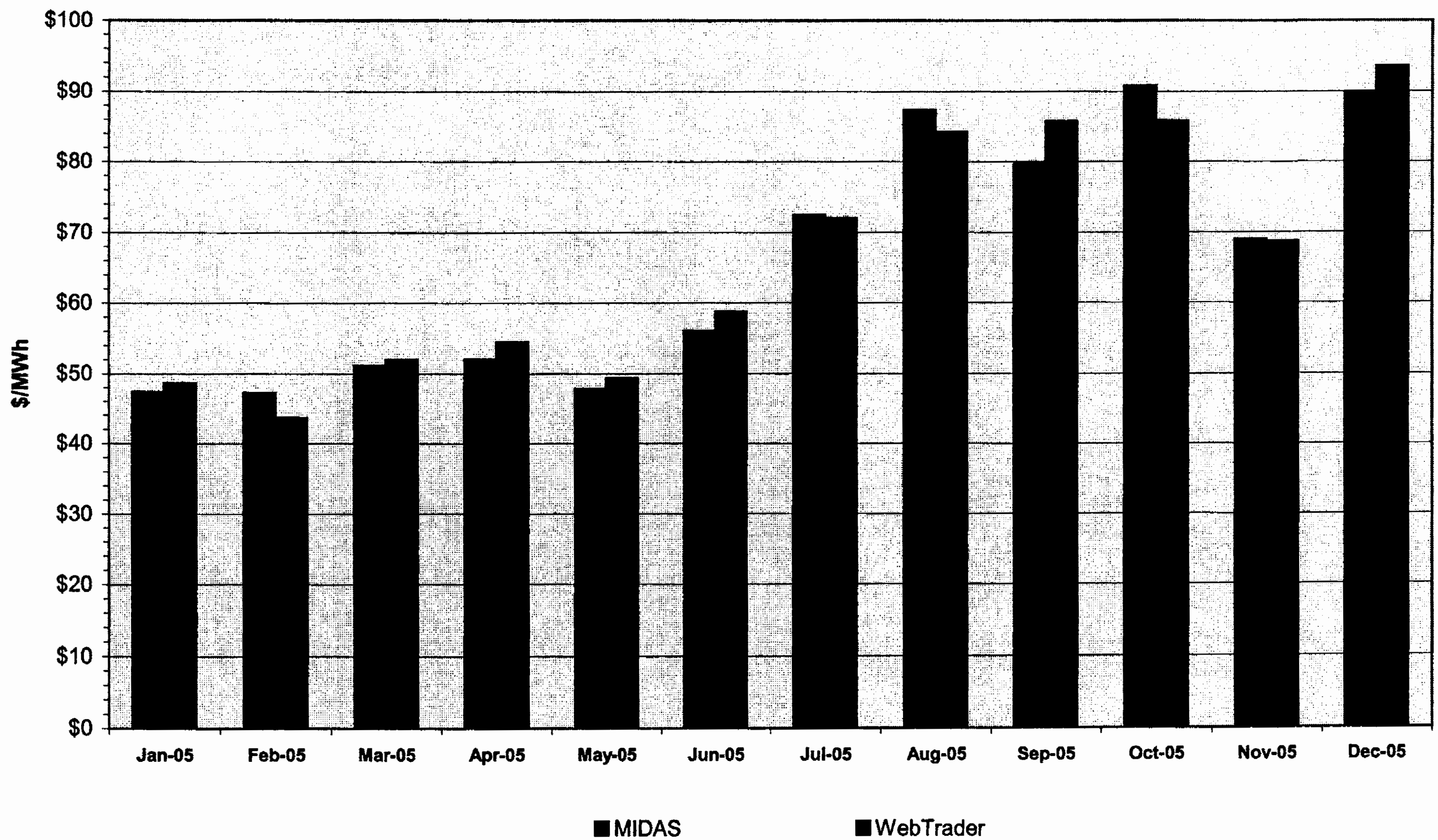
Subscribed and sworn before me this 30th day of January 2006.

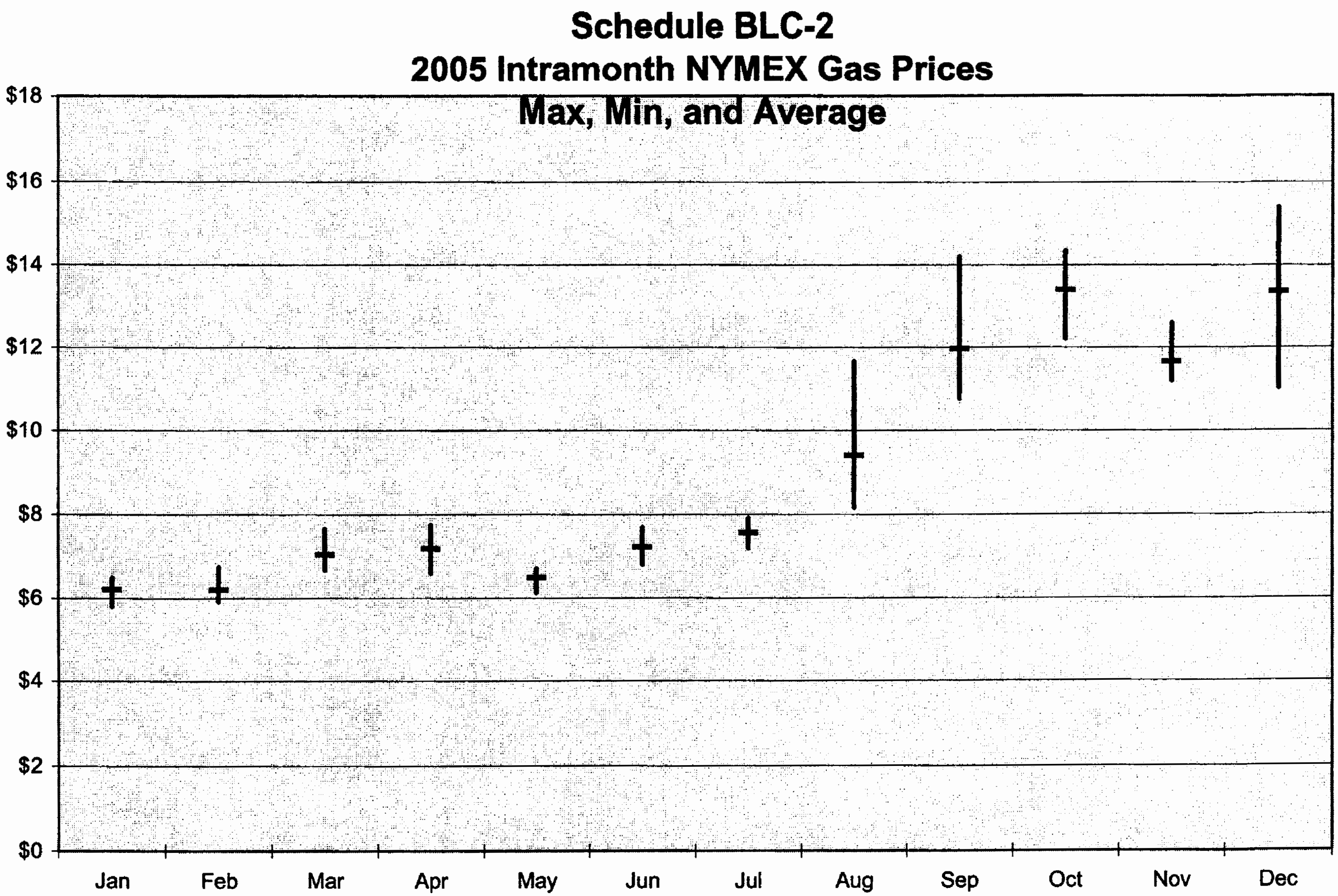
Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2007

NICOLE A. WEHRY
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires: Feb. 4, 2007

Schedule BLC-1
Backcast of MIDAS 2005 Power Prices
("Webtrader" represents hourly market observations entered into Webtrader software by KCPL power traders)




Schedule BLC-2
2005 Intramonth NYMEX Gas Prices
Max, Min, and Average
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Maintenance Schedule Normalization
Schedule BLC-3

Scheduled Maintenance Outages - Normalized Weeks

	Wolf Creek		La Cygne 1		La Cygne 2		Iatan		Hawthorn 5		Montrose 1		Montrose 2		Montrose 3		MW-Wks - By Category		
Type	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Frequency	Duration	Nuclear	Coal	Total
Boiler	18 Month	5.00	12 Month	4.00	18 Month	3.50	24 Month	4.25	24 Month	3.50	3 Year	3.50	3 Year	3.50	3 Year	3.50			
Turbine			6 Year	8.00	6 Year	7.50	5 Year	8.00	5 Year	8.00	6 Year	7.50	6 Year	7.50	6 Year	7.50			
Inspections									Annual	1.25	Annual	0.57	Annual	0.57	Annual	0.57			
Maintenance Cycle																			
Yr 1		5.00		4.00		3.50		4.25		3.50		0.57		0.57		0.57			
Yr 2		5.00		4.00		3.50		0		1.25		0.57		0.57		0.57			
Yr 3		0		4.00		0		4.25		3.50		3.50		3.50		3.50			
Yr 4		5.00		4.00		3.50		0		1.25		0.57		0.57		0.57			
Yr 5		5.00		4.00		3.50		8.00		3.50		0.57		0.57		0.57			
Yr 6		0		8.00		7.50				1.25		7.50		7.50		7.50			
Average Year		**3.33**		**4.67**		**3.58**		**3.30**		**2.38**		**2.21**		**2.21**		**2.21**			
MW		550		370		337		473		563		170		164		176			
MW-Wks Out		1,833		1,727		1,208		1,561		1,337		376		363		390	1,833	6,961	8,794
Days Out		23		33		25		23		17		15		15		15			

Itemized Costs for Annualized Fuel & Purchased Power
Schedule BLC-4

Energy (MWhr)

Sources of Energy

Generation Resources	
Nuclear	4,480,619
Coal	11,710,640
Combined Cycle	178,761
Gas Combustion Turbines	18,881
Oil Combustion Turbines	129
Wind Turbines	400,572
Total Generation	16,789,602
Purchased Power	
Non-Firm Wholesale Market	415,768
Capacity Contracts	1,601
Total Purchases	417,369
Total Sources of Energy	17,206,971

Uses of Energy

Native Load (Net System Input)	15,814,191
Firm Wholesale Obligations	1,392,780
Total Energy Sold	17,206,971

Cost of Service

Fuel Expense

Generation Fuel - Nuclear	19,008,048
- Coal / Steam	113,793,952
- CC and CTs	15,940,403
Start-Up Fuels	7,347,798
Fuel Adders	12,392,383
Total Fuel Expense	168,482,585

Purchased Power Expense

Purchases: Non-Firm Wholesale Market	36,408,402
Firm Contracts: Capacity Costs	6,302,801
Energy Costs	213,742
Total Purchased Power	42,924,945

Firm Wholesale Obligations Revenue

Energy Revenue	25,976,657
Capacity Revenue	11,205,000
Misc Fixed Cost Revenue	872,996
Total Firm Wholesale Obligations Revenue	38,054,653