PUBLIC VERSION

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BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

WM. EDWARD BLUNK

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 CONTINUE THE
IMPLEMENTATION OF ITS REGULATORY PLAN

DOCKET NO. 07-KCPE-____-RTS

Q: Please state your name and business address.

A: My name is Wm. Edward Blunk. 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" or the "Company") as Supervisor, Fuel Planning.

Q. What are your responsibilities?

A. My primary responsibilities are to develop fuel forecasts and strategies for fuel procurement and fuel inventory, which includes the development of strategies for and the management of KCPL's sulfur dioxide ("SO_2") emission allowance inventory.

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

A. In 1978, I was awarded the degree of Bachelor of Science in Agriculture Cum Laude, Honors Scholar in Agricultural Economics by the University of Missouri at Columbia. The University of Missouri awarded the Master of Business Administration degree to me in 1980. I have also completed additional graduate courses in forecasting theory and applications.

Before graduating from the University of Missouri, I joined the John Deere Company from 1977 through 1981 and performed various marketing, marketing research, and dealer management tasks. In 1981, I joined KCPL as Transportation/Special Projects Analyst. My responsibilities included fuel price forecasting, fuel planning and other analyses relevant to negotiation and/or litigation with railroads and coal companies. I was promoted to my present position in 1984.

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

A. I have previously testified before both the KCC and the Missouri Public Service Commission ("MPSC") on multiple issues regarding KCPL's fuel prices and fuel price forecasts, the competitive market for natural gas transportation, fuel inventory, and KCPL's SO_2 Emission Allowance Management Program.

Q. On what subjects will you be testifying in this proceeding?

A. I will be testifying on fuel market uncertainty and fuel costs, fuel inventory, and KCPL's SO_2 Emission Allowance Management Program.

I. <u>FUEL MARKET UNCERTAINTY and FUEL COSTS</u>

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of my testimony is to discuss historical and anticipated uncertainty and volatility in coal and natural gas fuel markets, and the impact of that uncertainty on KCPL's cost of service ("COS").

Q. How does fuel market uncertainty affect KCPL's COS?

A. Fuel market uncertainty affects the uncertainty of KCPL's cost of service in multiple ways. The first and most obvious impact is the effect of uncertainty in fuel prices and their direct effect on fuel expense. Uncertain or volatile fuel prices also affect off-system sales prices. KCPL witness Michael M. Schnitzer discusses the impact of gas price uncertainty on off-system sales in his direct testimony.

<u>Uncertainty vs. Volatility</u>

Q. Is uncertainty different from volatility?

A. In some contexts, volatility is synonymous with uncertainty. For the purpose of this testimony, I will use the word volatility to refer to "historical volatility," which is defined as the standard deviation of the daily change in the natural logarithm of the commodity's price for some period of time expressed as an annual rate. On the other hand, I will use the term uncertainty to indicate not knowing or being unsure. My testimony focuses more on price uncertainty than volatility.

Q. Generally people use the term "volatility" when speaking of movements in prices. Why are you drawing a distinction between volatility and uncertainty?

A. The levels of volatility that we are currently seeing in the markets for coal and natural gas, while high, are not unprecedented. In fact, they are merely on the high side of the ranges we have observed over the past few years. What is unusual about the current markets is the level of uncertainty and magnitude of the price movements we are now seeing. For example, in the latter part of June 2000 natural gas prices were about $4.40/MMBtu and 20-day volatility was 74 percent. That 74 percent represented a standard deviation of $3.26/MMBtu. In the latter part of December 2005, the average 20-day volatility was 76 percent but the settle price for the near month NYMEX contract was $12.50/MMBtu. That 76 percent now represented a standard deviation of $9.50/MMBtu, which is almost three times the level we saw in June 2000. Schedule WEB-1 compares the NYMEX near month settlement closing price with one standard deviation based on the 20-day volatility. It shows that since July 1990 there have been seven times when one standard deviation based on the 20-day volatility exceeded $6.00/MMBtu. While the first of those events occurred in December 2000, two occurred in 2006. It appears that the frequency and duration of these events is increasing.

Q. How has the level of uncertainty changed in the markets for natural gas and Powder River Basin ("PRB") coal?

A. Since about 2000, the level of uncertainty has increased significantly for both of these commodities. Both markets have shifted from being in states of supply-surplus to being supply-limited. A characteristic of supply-limited environments is that prices are set by the marginal buyer rather than the underlying supply curve. That means prices will rise until sufficient demand is destroyed as to bring supply and demand into balance. The specific factors driving demand and determining what price the marginal buyer will pay vary by commodity but are also interrelated.

Q. How will this shift from supply-surplus to supply-limited markets affect KCPL's fuel costs and COS?

A. Prices are higher in supply-limited markets than in supply-surplus markets. Prices are also more uncertain and volatile in supply-limited markets than in supply-surplus markets. Thus, as a result of the shift in these markets, KCPL's fuel costs are rising and, to the extent fuel supply is not "locked in", fuel costs are more uncertain.

<u>**Natural Gas Market Uncertainty**</u>

Q. Please explain the shift in the natural gas market from supply-surplus to supply-limited and the effect of this shift on natural gas prices?

A. The first revelation of the natural gas market being significantly supply-limited was in the winter of 2000/2001. As can be seen in Schedule WEB-2, which is a chart of population weighted winter heating degree days, the three winters preceding winter 2000/2001 were all warmer than normal with winters 1998/1999 and 1999/2000 being significantly warmer than average. Prior to the very cold winter of 2000/2001, the United States experienced a period of supply-surplus commonly referred to as the "gas bubble." As shown in Schedule WEB-3, natural gas storage levels were drawn down to unusually low levels in the very cold winter of 2000/2001. Natural gas prices responded by jumping to about $10.00/MMBtu, which was more than double the all-time high price (NYMEX near-month close) before September 2000. The natural gas industry responded with increased drilling, thereby increasing natural gas production. Before September 2000, there had never been more than 800 rigs devoted to natural gas. By May 2001 over 1,000 rigs were working on natural gas wells. This increased drilling activity, combined with the warmer than normal winter of 2001/2002, resulted in storage being filled to a new record level of 3,238 Bcf in December 2001.

As shown by Schedule WEB-2, the following winter 2001/2002 was very mild resulting in lower than normal demand. Storage at the end of winter 2001/2002 was 1,491 Bcf, a record high end of winter level. Prices dropped to less than $2.00/MMBtu. The industry again responded, but this time with decreased drilling. When prices started trending up later in 2002, the industry was much slower to respond. In fact, second quarter 2002 was the last quarter with U.S.-marketed natural gas production of more than 5,000 Bcf. Production in third quarter 2005, which includes some impact from Hurricanes Katrina and Rita, was only 4,668 Bcf. U.S.-marketed production had not been that low since third quarter 1993. Moreover, production for October 2005 was slightly less than 85 percent of average production for the preceding ten Octobers.

Schedule WEB-4 shows another disturbing trend. It shows that from May 1999 to October 2006 the number of rigs drilling for natural gas increased almost 300 percent while natural gas production essentially stayed flat. In brief, if the very high prices that are driving record drilling are not increasing production, then the United States is in a natural gas supply-limited environment. In a supply-limited environment for a commodity with price inelastic demand, prices can jump substantially during any supply disruption or surge in demand as prices search for a new demand/supply balance point.

Q. What factors are driving the increased price uncertainty in the natural gas market?

A. There are several factors driving the increased price uncertainty in the U.S. natural gas market. While the following list is not exhaustive, I believe it covers the key drivers:

- Uncertainty about what price is required to destroy marginal demand;
- The speed at which we can swing from supply-surplus to being supply-limited;
- The influence of hedge funds; and
- Changing demand projection paradigms.

Q. Why is there uncertainty about what price is required to destroy the marginal demand for natural gas?

A. The power industry tends to be the marginal customer for natural gas and effectively determines the upper bound on natural gas prices because of its ability as an industry to switch fuels. In the past few years, the complexity of determining when that fuel switching will take place has increased. Traditionally, it was assumed that when natural gas was more expensive than oil on a $/MMBtu basis, fuel switching would take place. While that may still be true in some situations, the fuel switch decision is made on a unit-by-unit basis. It is a function of regional anomalies such as taxes and fuel transportation rates, and the unit's power generation technology (*i.e.*, steam generators, combustion turbine, or combined cycle), which in turn affects the unit's heat rate, emission levels, environmental constraints, and minimum run times.

Q. What do you mean by the speed at which we can swing from supply-surplus to being supply-limited?

A. Significant weather events can have major immediate impacts on the supply/demand balance for natural gas. Winter 2000/2001, which I discussed earlier, and Summer 2005 both show just how quickly the natural gas market can swing from a supply-surplus to being supply-limited. Summer 2005 was the warmest in many years driving electric sector demand for natural gas to new levels. Exacerbating the supply/demand imbalance was the loss of significant quantities of natural gas production due to hurricanes. Summer/fall 2005 was one of the most active hurricane seasons on record. Hurricanes Katrina and Rita demonstrated just how much impact hurricanes can have on natural gas supply when they hit "platform alley" in the Gulf of Mexico. Fortunately, Hurricanes Katrina and Rita did not traverse the most densely rig/platform populated section of "platform alley."

Hurricanes Katrina and Rita made landfall on August 28, 2005 and September 19, 2005, respectively. They were a major turning point for the natural gas industry. In the January 19, 2006 release of the U.S. Minerals Management Service ("MMS") report, *Impact Assessment of Offshore Facilities from Hurricanes Katrina and Rita*, MMS Regional Director Chris Oynes said, "The overall damage caused by Hurricanes Katrina and Rita has shown them to be the greatest natural disasters to oil and gas development in the history of the Gulf of Mexico. Just last year [2004], in the devastating Hurricane Ivan, there were seven platforms destroyed, compared with the 115 platforms destroyed in Katrina and Rita." Schedule WEB-5 shows that production following Hurricanes Katrina and Rita dropped to levels not seen since September 1989. Before Hurricanes Katrina and Rita, MMS estimated that natural gas production in the Gulf of Mexico was about 10 Bcf per day. On June 21, 2006, MMS issued its final report on the effects of Hurricanes Katrina and Rita. MMS reported that, "the cumulative shut-in gas production 8/26/05-6/19/06 is 803.604 Bcf, which is equivalent to 22.017 % of the yearly production of gas in the GOM [Gulf of Mexico]". Consequently, the predictions based on long-range weather trends, suggesting that we are at the beginning of a decades-long season of hurricanes like 2005, further increase the uncertainty of natural gas production and drive even more price uncertainty.

Q. How are hedge funds affecting the natural gas market?

A. The influx of new hedge funds into the energy market has increased market volatility and uncertainty. Ron Denhardt, vice president of natural gas services at Strategic Energy and Economic Research put it this way in the April 22, 2005, edition of Platts' *Inside FERC's Gas Market Report*, "The way I'm seeing the market is that unless there is strong evidence the [supply/demand balance] is too loose, people playing the paper market can drive prices all over the place."

Q. What demand projection paradigms are changing that add uncertainty to our understanding of the natural gas market?

A. As I discussed earlier, the algorithm for determining power sector demand has become more complex. It is no longer a simple comparison between the price of natural gas and oil on a $/MMBtu basis. Schedule WEB-6 shows that gas-fired generation summer capacity in the power industry has more than doubled since 1996. Moreover, in 1996 natural gas summer capacity was 35 percent less than coal, but in 2005 natural gas capacity was 31 percent more than coal. That increase in demand potential happened at the same time other natural gas demand was being destroyed. We have not yet seen what all of that new gas-fired capacity could do to demand.

Q. When do you expect the price uncertainty in natural gas markets to decrease?

A. Weather is a key driver in natural gas market uncertainty. With winter 2005/2006 being mild and December 2006 being the warmest on record, natural gas demand has been much lower than normal. Decreased production levels may be masked by this lower demand. The expectation that hurricane seasons like 2005 may be the new norm, the possibility of a warmer than normal summer either followed or led by a colder than normal winter, are just a few of the factors that lead me to believe that while we may see lower prices, natural gas price uncertainty will not decrease until after new supply increases significantly. The earliest new supply that might come on-line would be liquefied natural gas ("LNG") imports.

Q. Will LNG have a significant impact on mitigating uncertainty in natural gas markets?

A. I don't think so. The Energy Information Administration ("EIA") expects a revitalization of U.S. LNG imports during 2007 and 2008 with year-over-year changes of 34.5 and 38.5 percent, respectively, and ultimately reaching approximately 1,080 Bcf in 2008. That is in spite of the fact that the volume of LNG imports has decreased over the past two years. As seen in Schedule WEB-1, the past two years had relatively high prices for the United States. The issue with LNG is that it is a global market. Price competition in both the Atlantic and Pacific Basins, particularly from the Atlantic Basin's Spain and the United Kingdom, has recently limited spot shipments of LNG to the United States. EIA's LNG import forecast is based in part on expected supply expansion in the global market. EIA expects increasing global LNG supplies to ease price pressure in the world market over time, which could result in the United States attracting a greater share of available LNG cargoes. Even so, EIA's projected increase in LNG imports would only increase total U.S. natural gas supply by about two percent.

Q. When will natural gas prices return to their historic norms?

A. We do not expect natural gas prices to return to the $3.31/MMBtu historic price (average near-month NYMEX close 4/4/90-12/31/05). That compares to the price average for 2006 of $6.98/MMBtu. The EIA's January 2007 *Short-Term Energy Outlook* shows Henry Hub natural gas prices are projected to average $7.06/MMBtu in 2007 and $7.72/MMBtu in 2008, which are down from EIA's January 2006 forecasted average price of $9.80/MMBtu for 2006 and $8.84/MMBtu for 2007.

<u>Natural Gas Price Hedging</u>

Q. Does KCPL have a program for managing the price risk of natural gas?

A. Yes. In 2001, KCPL implemented a Natural Gas Price Risk Hedging Policy approved by the KCPL Risk Management Committee.

Q. Please describe KCPL's natural gas price hedging program.

A. In 2001, KCPL retained Kase and Company, Inc. ("Kase and Company"), a risk management and trading technology firm, to assist in establishing a risk management program, which employs a disciplined, methodical approach to hedging. KCPL's program is oriented toward finding a balance between the need to protect against high prices while not unreasonably limiting opportunities to purchase gas at low prices. This balance is sought through the use of Kase and Company's HedgeModel. The objective of KCPL's price risk management program is to reduce the price risk inherent with floating with the market.

** [redacted]

[redacted]**

Q. How does KCPL determine the amount of natural gas to hedge under its price risk management program?

A. **[redacted]

[redacted]**

Q. How often does KCPL use the HedgeModel?

A. KCPL monitors the HedgeModel daily. **[redacted]**

Q. How well has this program performed for KCPL?

A. The purpose and value of the hedge program is to limit or reduce the exposure of the Company to natural gas market price risk. KCPL has used this program to hedge natural gas price risk since 2002. Each year the program has been employed, it reduced KCPL's exposure to price risk from natural gas by **[redacted]**

In addition to accomplishing the primary program purpose of reduced price risk exposure, results of the hedge program compared favorably to spot gas pricing for the months with hedges. Since KCPL's hedge program was implemented in 2002, the Company's average "all-in" price of hedged natural gas has been **[redacted]** That compares favorably to the weighted average *Gas Daily* spot price of **[redacted]** for the days the Company burned natural gas.

<u>Coal Market Uncertainty</u>

Q. What coal markets supply KCPL's coal requirements?

A. KCPL buys about 97 percent of its coal requirements from the PRB with most of that coal coming from the South Gillette and Wright areas. The remaining three percent of KCPL's coal requirements comes from bituminous mines in the Midwest, but primarily Kansas and Missouri.

Q. What is the Powder River Basin?

A. The PRB is the single largest source of coal mined in the United States and contains one of the largest deposits of coal in the world. The PRB is divided into two separate producing regions, the Southern PRB ("SPRB") and the Northern PRB ("NPRB"). The SPRB is located in Campbell and Converse counties in northeastern Wyoming. It is subdivided into the North Gillette, South Gillette, Wright, and Thunder Basin areas. The South Gillette and Wright areas are located 7 to 60 miles south of Gillette, Wyoming. The mines in SPRB are large. As a point of comparison, Kansas and Missouri together produced about 770,000 tons of coal in 2005. The smallest single mine in SPRB produced more than 4 million tons of coal in 2005. The largest SPRB mine produced more than 90 million tons of coal in 2006 or about seven percent of total United States production.

Q. How have PRB coal prices demonstrated uncertainty?

A. In January 2006, PRB coal prices reached a new all time high of $21.50/ton for 8800 Btu/lb spot coal. January 2006, however, turned out to be very warm and that resulted in lower coal demand. The lower coal demand combined with a surge in coal production to push PRB prices down. Now, about a year later, PRB 8800 Btu/lb spot coal is about $8.20/ton. That is about a 60 percent decrease. We can now look back and compare the peak price to the prices preceding the run-up. The price run that culminated in the $21.50/ton peak price started near the end of first quarter 2005. Prior to the run, prices had been reasonably steady, averaging about $6.30/ton. In less than 12 months, the price of PRB coal jumped more than 240 percent. Prior to 2006, the peak PRB price was $13.75/ton set in May 2001. That price peak was about 210 percent more than the average preceding its run-up. While two observations do not establish a pattern, it is worth noting that twice in a little more than five years, PRB prices have jumped more than 200 percent.

Q. What factors are driving the increased price uncertainty in PRB coal markets?

A. The main factor driving price uncertainty in PRB coal is effective productive capacity. That, combined with inelastic demand, means prices can jump dramatically whenever there is a disruption in production or surge in demand. Other factors adding uncertainty to PRB coal markets include the influence of speculative traders and clean air regulations.

Q. What is the production history of the PRB?

A. Prior to the 1970s, the PRB coal industry was undeveloped. In 1975, production from SPRB was about 3 million tons per year (mmtpy). In 1976, the U.S. Supreme Court issued a pro-coal decision in the case of Kleppe v. Sierra Club, 427 U.S. 390 (1976), and SPRB production took off. In three years, six new mines opened. By 2001, production for the entire SPRB was up to 354 mmtpy. That was an annual compound growth rate of 20 percent. Since 2001, SPRB production has only grown at about three percent per year.

Q. What has changed to so dramatically reduce growth in production from SPRB?

A. SPRB producers only produce enough coal to satisfy demand. From their perspective that demand is measured by how many trains show up for loading. The number of trains that show up for loading is a function of the consumers' demand for coal, as limited by the railroads' ability to transport the coal. While there are multiple factors that have converged to reduce the growth in production from SPRB, the most obvious is the limitation of the transportation system. It appears that the railroads were running into their effective capacity limit in 2001. They were able to ship 63 trains per day but could not sustain that level for any ninety-day period. While the railroads have added capacity since 2001, they have not built any excess. As the events of 2005 showed, they did not have enough margin in their system to absorb major derailments. Regarding the mines themselves, capacity in PRB is adequate to handle demand growth. More significant is that production philosophies have changed. Most of the productive capacity of SPRB has transitioned from privately held companies to publicly traded companies creating greater pressure on the coal company management to produce market returns on investment. The more highly leveraged private companies were more focused on the cash flow necessary to support their debt coverage. Consequently, coal company management is now more willing to limit production if that is what is necessary to earn higher returns.

Q. Has transportation impacted PRB production since 2001?

A. Yes. On May 14 and 15, 2005, the Burlington Northern Santa Fe Railway ("BNSF") and the Union Pacific Railroad ("UP") experienced back-to-back derailments on the "Joint Line", a shared section of track serving the southern end of the PRB. The two derailments and the resulting intensive Joint Line maintenance program that lasted from July 2005 into 2006, disrupted the flow of trains to and from the PRB.

Today, over 350 million tons of SPRB coal move across the Joint Line annually. The result of the derailments was a significant depletion of PRB coal stocks nationwide. PRB coal stocks dropped to historic lows. The EIA's data, as reflected in Schedule WEB-7, shows that coal inventories for those states that rely heavily on PRB coal dropped 30 percent from April through September 2005. While those stocks have not fully recovered, they no longer appear to be supporting high market prices.

Q. How are speculative traders adding price uncertainty to the market for PRB coal?

A. When speculative traders take short positions, that is, they sell coal they do not have, they can be caught by unexpected illiquidity in the market and drive the price up in a desperate attempt to get the coal they need to fulfill their contractual obligation. It was rumored that the 2001 price spike for PRB coal, which is also evident in Schedule WEB-7, was driven by a speculative trader(s) being caught short and having to buy to satisfy those commitments. The December 2005 price run-up may have had a similar driver. According to the December 21, 2005 edition of *Coal & Energy Price Report*, some traders may have been short for early 2006 coal. Apparently, after 8800 Btu/lb PRB coal ran up to $20.00/ton in October and then dropped to $14.00/ton, these traders expected the market to return to its old norm of less than $14.00/ton. They sold short with the expectation of covering their positions later when the market returned to the old normal levels. Instead, the market rebounded to over $20.00/ton. Exacerbating the problem is the fact that PRB producers are using a sales tactic they have used before when market conditions were tight. The producers are not selling their coal on the spot market, but only under contracts with terms of at least two to three years.

Before February 2001, 8800 Btu/lb PRB spot coal generally traded between $4.00 and $5.00/ton. In first quarter 2001, the price skyrocketed from about $4.60/ton to $12.00/ton, and by May 2001 it had reached $13.75/ton. In five months' time, the price of PRB coal had increased about 200 percent. We observed an even greater price jump in 2005. In March 2005, Evolution Markets reported a settlement price for 8800 PRB spot coal of $6.25/ton. On December 30, 2005, they reported a settlement price of $22.00/ton, an increase of more than 250 percent. As I discussed earlier, there were fundamental reasons causing the price to move up. It appears the impact of the speculative trades is they cause the price to move faster and further than it might otherwise.

Q. How are clean air regulations impacting the market for PRB coal?

A. When SO_2 emission allowance prices climbed to $1,500 per SO_2 emission allowance in December 2005, that was the equivalent of adding about $80/ton or $3.50/MMBtu to the price of unscrubbed Illinois Basin coal. On the other hand, the promulgation of the Clean Air Interstate Rule ("CAIR") and Clean Air Mercury Rule ("CAMR") continue the trend of ever more stringent limitations on power plant emissions. These regulations have and will impact fuel markets. Energy Ventures Analysis, Inc. estimates that over 140 GW of new Flue Gas Desulfurization ("FGD") controls will be required to comply with CAIR and CAMR. The addition of FGD scrubbers will reduce the relative attractiveness of low-sulfur PRB coal versus higher-sulfur eastern coal.

Q. Are there other factors affecting or adding uncertainty to the cost of coal?

A. In addition to the factors discussed above, which focus on the mine price, are the railroads' new pricing policies.

Q. What are the railroads' new pricing policies?

A. The policies are best described in the railroads' own words. Union Pacific Chairman and Chief Executive Officer Dick Davidson stated in his letter to shareholders in Union Pacific Corporation's 2004 Annual Report the following:

> "Unprecedented levels of demand have created a very strong pricing environment that we are working diligently to convert into higher returns on investment. Across all business groups, **we are obtaining solid price increases** in the marketplace. At the same time, we are working to reduce the complexity and inflexibility of long-term contracts so that we can respond more quickly to changing market conditions. One clear example is in our coal business where we have instituted **new coal pricing mechanisms for all shipments from the Southern Powder River Basin (SPRB) in Wyoming**, as well as spot movements

> out of Colorado and Utah. We have simplified the way we do business with our customers by clearly communicating the revenue we need in order to reinvest in our coal business, while sharply reducing the administrative burden of dozens of separate contracts. In total, 322 million tons of coal moved out of the SPRB [South Gillette and Wright areas] in 2004, and that is expected to grow to over 500 million tons by 2013. Our goal is to participate in meeting that growing demand, **but only if the financial returns are sufficient to justify the necessary investment.**" (emphasis added)

Q. What do those "new coal pricing mechanisms" look like in practice?

A. Union Pacific instituted "Circulars" and Burlington Northern Sante Fe instituted "Pricing Authorities." To avoid antitrust violations from public price disclosure, both railroads have argued that these pricing mechanisms are tariffs subject to review by the Surface Transportation Board. KCPL's first rate to be exposed to these new coal pricing mechanisms is for the shipment of coal from SPRB to Montrose. The effective rate jumped **[redacted]** when KCPL's contract rate expired and the new Circular pricing mechanism became effective January 1, 2006. This is about a **[redacted]** per year increase.

Q. Is KCPL the only one paying these higher rates?

A. No. New western rail rates are much higher today than they were even just a few years ago. As existing contracts expire, the railroads are not negotiating new contracts but are imposing their new public prices. Prior to this change in the railroads' pricing philosophy, they were bidding 8 to 9 mills/ton-mile for typical SPRB moves. Now they are charging rates for competitive moves as high as 20 mills/ton-mile and adding a fuel surcharge on top of that. That is more than double the old rates. For moves like KCPL's, that would increase the delivered cost of coal anywhere from 50 to 60 percent. **[redacted]

[redacted]**

<u>**Coal Price Hedging**</u>

Q. Does KCPL have a program for managing the price risk of coal?

A. Yes, it does.

Q. Please describe KCPL's coal price hedging program.

A. **[redacted]

[redacted]**

Q. How has this strategy performed for KCPL?

A. **[redacted]**

Q. Please explain what KCPL means by the cost of coal is "locked in"?

A. KCPL has contractual commitments for all of its expected coal requirements for 2007, approximately 95 percent for 2008, 45 percent for 2009, and 35 percent for 2010. All of our contracts specify base prices, which are subject to certain adjustments, primarily for quality, and in some cases certain measures of inflation. Except for those adjustments we know what the price of our coal will be for these contracted quantities.

Q. What do you expect the price of KCPL's coal to be through 2008?

A. **[redacted]**

<u>**Fuel Price Forecast**</u>

Q. What fuel prices did KCPL use to develop its COS?

A. I provided KCPL witness Burton Crawford projected fuel prices that he used to develop the annualized fuel expense included in COS that resulted in Adj-38, "Annualize Fuel Expense at contract prices for net system input normalized for weather " included in Schedule JPW-2 of the direct testimony of KCPL witness John P. Weisensee.

Q. How did you forecast the natural gas prices?

A. Natural gas prices are based on the average of the six business days from January 24 through January 31, 2007, for the NYMEX closing prices for the September 2007 Henry Hub natural gas futures contract. Given the September 2007 price, the prices for the other months in the COS were developed by applying the long-term average relationship of each month's closing price to the following September. The monthly Henry Hub prices were then adjusted for basis using the average of the six business days from November 28 through December 5, 2006, Gas Daily basis forwards assessments. These basis-adjusted values for October 2006 through September 2007 were used to develop the cost of natural gas in the COS. Natural gas transportation and hedging related costs were included in the COS as "fuel adders."

Q. How did you forecast the oil prices?

A. Oil prices are handled differently than natural gas because KCPL uses oil differently. Oil is used primarily for flame stability and startup at coal units. The price of oil used for flame stability and startup is based on the average of the six business days from January 24 through January 31, 2007, for the NYMEX closing prices for the September 2007 heating oil futures contract. The heating oil futures contract price is adjusted for basis and transportation to determine the station-specific delivered cost. Northeast on the other hand uses oil as a primary fuel. For modeling purposes, Northeast was dispatched using replacement fuel prices like those used for flame stability and startup. Northeast fuel expense, however, was determined using Northeast's average inventory value.

Q. How did you forecast the coal prices?

A. The September 2007 delivered prices of PRB coal were forecast as the sum of mine price and transportation rate. All of KCPL's expected coal burn for 2007 is under contract. **[redacted]**

Freight rates for those shipments of PRB coal that are under contract with a railroad were forecast by using indices forecast by Global Insight to drive the contractual pricing mechanism. For those shipments under "Circular" (or tariff) the base freight rates are specified by the Circular. In accordance with the terms of the Circular, a fuel surcharge is added to the base rate. That fuel surcharge was projected to September 2007 by using Global Insight's forecast for light fuel oil to project DOE's "Retail On-Highway Diesel Fuel" price, which is used by the Circular's rules to determine the fuel surcharge.

The September 2007 price for KCPL's long-term bituminous coal contract was the contractually specified price for 2007. The remainder of KCPL's bituminous coal requirements were priced using prices paid for similar supplemental purchases in 2006.

Q. Are there costs related to fuel and included in Adj-38 that are not included in the price of fuel?

A. Yes. We refer to those costs as "fuel adders." They include unit train lease expense, unit train lease revenue, unit train maintenance, unit train property tax, natural gas hedging costs, and costs associated with transporting natural gas.

Q. Please describe the unit train-related expenses.

A. Unit-train related expenses include the following:

- Unit train lease expense, which is disaggregated into three components:

  Long-term unit train lease expense;

  Short-term unit train lease expense; and

  [redacted].

- Unit train maintenance expense consisting of:

  Foreign car repair;

  Shared expenses; and

  Maintenance and repair of KCPL's railcar fleet.

- Unit train property tax.

Long-Term Unit Train Lease Expense: The amount presented here for unit train lease expense reflects KCPL's share of the long-term lease payments that will be made for unit trains that will be in KCPL's service in September 2007. It includes an annualization of reductions resulting from refinancing a railcar lease and the loss of cars destroyed in derailments.

Short-Term Unit Train Lease Expense: Short-term unit train lease expense has two subcomponents. The first reflects our estimate of KCPL's net lease expense under our unit train exchange agreement. That agreement allows us to exchange trainsets among the different plants within our system recognizing that ownership interests in Iatan and LaCygne are different from those of Hawthorn and Montrose. The other subcomponent is our estimate of railcar capacity that will be acquired through the short-term railcar lease market to move KCPL's coal requirements.

[redacted]

Foreign Car Repair: This represents the cost of repairing railcars that are running in service for KCPL but are not owned by or under a long-term lease to KCPL.

Shared Expenses: These are costs for things like AAR publications, UMLER fees, and railcar management software fees that can not be assigned to an individual car.

Maintenance and Repair of KCPL's Railcar Fleet: These repair values have been adjusted and annualized to reflect the addition of new trainsets to KCPL's fleet in 2006.

Ad valorem private car line taxes: Unit train property tax is tax that KCPL pays on its railcar fleet. The value included here has been adjusted to reflect changes in tax rates and fleet makeup.

Q. Why are ad valorem private car line taxes included as a "fuel adder" and not recorded as property taxes?

A. Federal Energy Regulatory Commission account rules require that "Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point" be recorded in Account 151 Fuel Stock as part of the cost of fuel.

Q. Are unit train depreciation expenses included in the "fuel adders"?

A. No. Unit train depreciation expense is included in the Depreciation annualization in Schedule 5 of the Revenue Requirement Model sponsored by KCPL witness John P. Weisensee and attached to his direct testimony as Schedule JPW-1, and then transferred to Fuel expense in Schedule 4 of the Model.

Q. How did you determine the natural gas hedging costs?

A. The natural gas hedging costs are based on the relationship of our historical gas hedging costs to the projected value of the natural gas those hedges were to safeguard. That historical relationship, defined as a percent of the projected value, was applied to the value of natural gas our hedge program would shield given the natural gas requirements identified in this case.

Q. What are the costs associated with transporting natural gas?

A. The costs components for transporting natural gas include the following: reservation, commodity, minimum annual payment, commodity balancing fees, transportation charges, access charges, mileage charges, fuel and loss reimbursement, FERC annual charge adjustment, storage fees, and parking fees. I also included in these costs, a credit for the Tight Sands Refund ordered by the Missouri Public Service Commission in Case No. GR-91-286.

Q. How did you determine the costs associated with transporting natural gas?

A. I disaggregated the cost of transporting natural gas into its various components. For those items specifically defined by tariff or contract, we used the defined mechanism. I estimated parking fees based on prior period actuals. The estimated credit for the Tight Sands Refund was based on the prior period actual. Those subcomponents were then aggregated and added to the specific tariff costs to determine the total cost of transportation. These costs are included in KCPL's COS as fuel adders.

Q. What is "Adj-62 STB Litigation" as shown in the Summary of Adjustments in Schedule JPW-2, attached to the direct testimony of KCPL witness John P. Weisensee?

A. The Company filed a rate complaint case on October 12, 2005, with the Surface Transportation Board ("STB"). In that rate complaint, KCPL charged that Union Pacific Railroad's (UP) rates for the movement of coal from origins in the Powder River Basin of Wyoming to KCPL's Montrose Generating Station were unreasonably high. Adj-62 reflects an adjustment to operating income related to this rate complaint case. KCPL witness John P. Weisensee discusses this adjustment in his direct testimony.

Q. Why has KCPL filed a rate complaint with the Surface Transportation Board?

A. KCPL's Montrose Station is captive to the UP; that is, UP is the only railroad that holds out to provide coal delivery service from SPRB to the Montrose Station. In anticipation of the need for unit train coal service to Montrose Station after 2005, KCPL expressed to UP its desire to negotiate an extension of the 1995-2005 contract or a new contract. Consistent with the public pronouncements made at the unveiling of its Circular 111 (tariff) program in March 2004, UP insisted that it would only transport PRB coal to Montrose Station after December 31, 2005, under rates and terms set forth in Circular 111. According to UP's 2004 Annual Report, this tariff was intended to be a "new coal pricing mechanism for all shipments from Southern Powder River Basin (SPRB) in Wyoming…." In the absence of a successor agreement to its existing contract, KCPL had no means to procure PRB coal delivery service to the Montrose Station other than under the terms of UP's common carrier Circular 111 even though KCPL did not consider the rates and service terms in the Circular to be equitable or reasonable. KCPL accepted the terms of UP's Circular 111 under duress and subsequently filed a rate complaint with the STB, the agency which governs captive shipper rail rates.

Q. Why are the costs of that rate complaint case so high?

A. The STB is the exclusive forum available for contesting rates for railroad services. Before the STB will prescribe rate relief, a shipper must meet three burdens of proof. First, the shipper must prove that it is subject to railroad "market dominance", *i.e.*, that it is captive. Market dominance means that there are no other transportation options available to the rail customer. Second, the shipper must prove that it is paying a rate that is above the legal threshold. That is, the revenue from the rate must exceed 180% of the variable cost to provide the service. Third, the rail customer must prove that its rate is "unreasonably high." The standard that the STB uses for determining if a captive rail shipper's rate is "unreasonably high" is a concept called "stand-alone cost." The "stand-alone cost" is the lowest cost at which a hypothetical, efficient "stand-alone railroad" could provide the transportation service required by the complaining shipper. The costs of building and operating such a railroad are then compared to the revenues that such a system could expect to earn. If the shipper demonstrates that the stand-alone railroad would earn more from its shippers than is necessary to cover all of its costs, the shipper is entitled to rate relief. In a stand-alone cost rate case, the parties typically litigate over many issues, such as how much traffic might be carried by the stand-alone railroad; how the stand-alone railroad would have to operate in order to meet the requirements of the railroad's shippers; how much it would cost to conduct such operations; and how much revenue the system would generate. To develop this hypothetical railroad, the captive shipper must retain lawyers, accountants, railroad economists and other such experts. Because of the evidentiary and burden of proof requirements set by the STB, the costs for determining the "stand-alone costs" of a "stand-alone railroad" are substantial.

Q. What is the status of the STB case?

A. On February 27, 2006, the STB suspended KCPL's case, STB Docket No. 42095, while it pursued a rulemaking proceeding (Ex Parte No. 657 (Sub-No. 1)) to address major issues regarding the proper application of the stand-alone cost test in rail rate cases and the proper calculation of any rail rate relief. Then on July 26, 2006, the STB ordered KCPL and UP to submit briefs on the issue of whether the STB had jurisdiction to entertain the rate complaint. In previous filings, both KCPL and UP had asserted that the Board had jurisdiction to determine the reasonableness of the challenged rates. The Board was now questioning if the "Volume Commitment Certificate" required by the Circular to provide notice to the UP of which rate provision KCPL had elected under the

Circular constituted a contract because the selected rate option set rates for a term of three years, a minimum-volume requirement for KCPL, a service commitment for UP, a liquidated damages provision if either party failed to meet its obligations under the agreement, and a force majeure clause. Under 49 U.S.C. 10709(c), the STB has no jurisdiction over rail transportation contracts. KCPL and UP filed those briefs September 25, 2006. As of February 21, 2007, the Montrose case is still in abeyance because the Board had not issued a ruling on the matter.

On October 30, 2006, the STB issued its order in the Ex Parte No. 657 (Sub-No. 1) rulemaking. The STB claims that its new rules will simplify the rate review process. **[redacted]** Currently the STB's Stand-Alone Cost rulemaking proceeding (STB Ex Parte No. 657 (Sub-No. 1)) is being appealed before the District of Columbia Circuit. **[redacted]** We expect the appeal process will take 12-18 months to run its course, during which time KCPL will continue to press its current rate complaint. **[redacted]**

II. FUEL INVENTORY

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of my testimony is to explain the process by which KCPL determines the amount of fuel inventory to keep on hand and how the level of fuel inventory impacts KCPL's COS.

Q. Why does KCPL hold fuel inventory?

A. KCPL holds fuel inventory because of the uncertainty inherent in both fuel requirements and fuel deliveries. Both fuel requirements and deliveries can be impacted by weather. Fuel requirements can also be impacted by unit availability; both the availability of the unit holding the inventory and the availability of other units in KCPL's system. Fuel deliveries can also be impacted by breakdowns at a mine or in the transportation system. Events like the flood of 1993 and the 2005 joint line derailments interrupt the delivery of coal to KCPL's plants. Fuel inventories are insurance against events that interrupt the delivery of fuel or unexpectedly increase the demand for fuel. All of these factors vary randomly. Fuel inventories act like a "shock absorber" when fuel deliveries do not exactly match fuel requirements. That is, they are the working stock that enables KCPL to continue generating electricity between fuel shipments.

Q. How does KCPL manage its fuel inventory?

A. Managing fuel inventory involves ordering fuel, receiving fuel into inventory, and burning fuel out of inventory. KCPL controls inventory levels primarily through our fuel ordering policy. That is, we set fuel inventory targets and then order fuel to achieve those targets. We define inventory targets as the inventory level that we aim to maintain on average during "normal" times. In addition to fuel ordering policy, plant dispatch policy can be used to control inventories. For example, KCPL might reduce the operation of a plant that is low on fuel to conserve inventory. Of course, this might require other plants in the system to operate more and to use more fuel than they normally would, or it might require either curtailing generation or purchasing power in the market. One can view this as a transfer of fuel "by wire" to the plant with low inventory. To determine the best inventory level, KCPL balances the cost of holding fuel against the expected cost of running out of fuel.

Q. What are the costs associated with holding fuel inventory?

A. Holding costs reflect cost of capital and operating costs. Holding inventories requires an investment in working capital. That requires providing investors and lenders those returns that constitute the cost of capital. It also includes the income taxes associated with providing the cost of capital. The operating costs of holding inventory include costs other than the cost of the capital tied up in the inventories. For example, we treat property tax as an operating cost.

Q. Please explain what you mean by the expected cost of running out of fuel?

A. The cost of running out of fuel at a power plant is the additional cost incurred when KCPL must use replacement power instead of operating the plant. If the plant runs out of fuel and replacement power is unavailable, KCPL could fail to meet customer demand for electricity. The cost of replacement power depends on the circumstances under which the power is obtained. We would expect replacement power (and the opportunity cost of forgone sales) to cost less at night than during the day and less on weekends than during the week. In other words, replacement power costs (and opportunity costs of forgone sales) are cyclical. A varying replacement power cost (or opportunity cost of forgone sales) translates directly into a varying shortage cost. As a result, if KCPL was running low on fuel it could mitigate the shortage cost by selectively reducing burn when the cost of replacement power is lowest. During any significant period of disruption, we would expect many replacement power cost cycles.

Q. How does KCPL determine the best inventory level, *i.e.*, the level that balances the cost of holding fuel against the expected cost of running out?

A. KCPL uses the Electric Power Research Institute's ("EPRI") Utility Fuel Inventory Model ("UFIM") to identify those inventory levels with the lowest expected cost. UFIM identifies an inventory target as a concise way to express the following fuel ordering rule:

Current Month Order = (Inventory Target – Current Inventory)
+ Expected Burn this Month
+ Expected Supply Shortfall.

That is, UFIM's target assumes all fuel on hand is available to meet expected burn. "Basemat" is added to the available target developed with UFIM to determine KCPL's inventory target. Generally, and in the rest of my testimony, references to inventory targets mean the sum of fuel readily available to meet burn plus basemat.

Q. What is basemat?

A. Basemat is the quantity of coal occupying the bottom eighteen inches of our coal stockpiles' footprints. It may or may not be useable due to contamination from water, soil, clay, or fill material on which the coal is placed. Because of this uncertainty about the quality of the coal, it is not considered readily available, but because it is dynamic and it can be burned, although with difficulty, it is not written off nor considered sunk. Eighteen inches was identified in previous KCPL cases as being the error range for placement of a dozer blade or scraper on a coal pile and the appropriate depth for basemat. For determining basemat under our compacted stockpiles, we only consider the area of a pile that is thicker than nine inches. The area of the coal piles that covers either a hopper or concrete slab is not included in the calculation of basemat. The basemat values presented here are based on work performed in August and September 2005 by MIKON Corporation, a consulting engineering firm that specializes in coal stockpile inventories and related services for utilities nationwide.

Q. How does the UFIM model work?

A. The fundamental purpose of UFIM is to develop least-cost ordering policies, *i.e.*, targets for fuel inventory. UFIM does this by dividing time into "normal" periods and "disruption" periods where a disruption is an event of limited duration with an uncertain occurrence. It develops normal-times inventory targets and disruption management policies. The inventory target that UFIM develops is that level of inventory that balances the cost of holding inventory with the cost of running out of fuel.

Q. What are the primary inputs to UFIM?

A. The key inputs are: holding costs, fuel supply cost curves, costs of running out of fuel, fuel requirement distributions, "normal" supply uncertainty distributions, and disruption characteristics.

Q. What are the holding costs you used to develop coal inventory levels for this case?

A. KCPL based the holding costs it used to develop fuel inventory levels for this case on the cost of capital structure proposed and described in the direct testimony of KCPL witness Samuel C. Hadaway.

Q. What do you mean by "fuel supply cost curves"?

A. The fuel supply cost curve recognizes that the delivered cost of fuel may vary depending on the quantity of fuel purchased in a given month. For example, our fuel supply cost curves for PRB coal recognize that when monthly purchases exceed normal levels we may need to lease additional trainsets. Those lease costs cause the marginal cost of fuel above normal levels to be slightly higher than the normal cost of fuel.

Q. What was the normal cost of fuel?

A. The normal fuel prices underlying all of the fuel supply cost curves were the same September 2007 projected prices I discussed earlier and that were used to determine the fuel expense in the COS, which KCPL witness Burton Crawford discusses in his direct testimony.

Q. What did you use for the costs of running out of fuel?

A. There are several components to the cost of running out of fuel. The first cost is the opportunity cost of forgone non-firm off-system power sales. I developed that cost by constructing a price duration curve derived from the distribution of monthly non-firm off-system MWh sales for 2003 through 2005. I supplemented those points with estimates for purchasing additional energy and using oil-fired generation. The last point on the price duration curve is the socio-economic cost of failing to meet load for which I used KCPL's assumed cost for unserved load. These price duration curves are referred to in UFIM as burn reduction cost curves. These burn reduction cost curves can vary by inventory, location and disruption.

Q. What fuel requirement distributions did you use?

A. In his direct testimony, KCPL witness Burton Crawford discusses how KCPL uses the MIDAS™ model as its production cost computer modeling tool for developing generation levels and resulting fuel expenses. The fuel requirement distributions used to develop the fuel inventory targets presented here were based on the burn projections underlying the fuel expenses discussed by Mr. Crawford.

Q. What do you mean by "normal" supply uncertainty?

A. We normally experience random variations between fuel burned and fuel received in any given month. These supply shortfalls or overages are assumed to be independent from period to period and are not expected to significantly affect inventory policy. To determine these normal variations, I developed probability distributions of receipt uncertainty based on the difference between historical burn and receipts.

Q. What are disruptions?

A. A disruption is any change in circumstances that persists for a finite duration and significantly affects inventory policy. A supply disruption might entail a complete cut-off of fuel deliveries, a reduction in deliveries, or an increase in the variability of receipts. A demand disruption might consist of an increase in expected burn or an increase in the variability of burn. Other disruptions might involve temporary increases in the cost of fuel or the cost of replacement power. Different disruptions have different probabilities of occurring and different expected durations.

Q. What disruptions did KCPL use in developing its inventory targets?

A. KCPL recognized three types of disruptions in development of its inventory targets:

- PRB capacity constraints;
- Fuel yard failures; and
- Major floods.

Q. Please explain what you mean by disruptions related to PRB capacity constraints.

A. Supply capacity is the ultimate quantity of coal that can be produced, loaded, and shipped out of the PRB in a given time period. Constraints to supply capacity can come from either the railroads or from the mines, but regardless of which of these is the constraint source, the quantity of coal that can be delivered is restricted. A constrained supply caused by railroad capacity constraints can come from an inability of the railroad to ship a greater volume of coal from the PRB. A scenario such as this can arise from not having enough slack capacity to place more trains in service. It can also come from an infrastructure failure such as the May 2005 derailments on the joint line in SPRB I discussed earlier. A constrained supply caused by the mines can come from situations such as there not being enough available load-outs, or not enough space to stage empty trains, or reaching the productive limits of equipment such as shovels, draglines, conveyors, and trucks or the mine reaching the production limits specified in its environmental quality permits.

Q. Please explain what you mean by disruptions related to fuel yard failures.

A. KCPL and other utilities have experienced major failures in the equipment used to receive fuel. Perhaps KCPL's most significant fuel yard failure occurred in 1986 when a conveyor belt caught fire at Hawthorn. The ensuing fire destroyed Hawthorn's normal facilities for unloading coal received by train. As used here, "disruption" is designed to cover a variety of circumstances that could result in a significant constraint on a plant's ability to receive fuel.

Q. Please explain what you mean by "Major flood" disruptions.

A. The third disruption we recognized in developing targets for this case was modeled after the 1993 flood. A large flood such as the flood of 1993 can lengthen railroad cycle times and curtail the deliveries of coal to generating stations. For example, at Iatan Station the average standard deviation in cycle time for the flood year is nearly double the standard deviation of the year before or after the flood, and during the months most affected by flooding, the differences are even more substantial.

Q. How does KCPL manage disruptions?

A. The target inventory levels presented here assume KCPL will actively manage its fuel inventory. That is, the Company would take whatever actions were deemed appropriate to ensure an adequate supply of fuel was kept on hand for generating energy necessary to serve native load. If KCPL runs low on fuel, it might choose to curtail generation and reduce burn. KCPL would manage the cost of any such disruption to take advantage of replacement power cost cycles. This assumption allows us to operate with lower inventory targets.

Q. What are the coal inventory targets used in this case?

A. The coal inventory targets resulting from application of UFIM and their associated value for incorporation into rate base are shown in the attached Schedule WEB-8 (Confidential) and are the values used to determine Adj-51, "Adjust Fossil Fuel Inventories to required levels" included in the Summary of Adjustments in Schedule JPW-2 of the direct testimony of KCPL witness John P. Weisensee. Since these coal inventory targets are a function of fuel prices, cost of capital and other factors that may be adjusted in the course of this proceeding, we expect to adjust the coal inventory targets as necessary.

Q. How were the inventory values for oil, lime, and limestone determined?

A. Inventory values for oil, lime and limestone were calculated as the average month-end quantity on hand for the 13-month period September 2005 through September 2006 multiplied by the September 2006 per unit value, i.e., price for inventory per the Company's accounting records. These values are also shown in Schedule WEB-8 (Confidential) and were included in the derivation of Adj-51.

III. KCPL'S SO_2 EMISSION ALLOWANCE MANAGEMENT PROGRAM

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of my testimony is to describe how KCPL's SO_2 emission allowance management program impacts KCPL's COS and rate base, to review the actions KCPL has taken under its initial SO_2 Plan, and to describe KCPL's 2007 SO_2 Plan.

Q. How does KCPL's SO_2 allowance management program impact KCPL's COS and rate base?

A. KCPL was authorized to manage its SO_2 emission allowance inventory, including the sales of such allowances, under the Stipulation and Agreement ("Regulatory Plan Stipulation and Agreement") that the KCC approved in Docket No. 04-KCPE-1025-GIE (the "1025 Docket"). The Regulatory Plan Stipulation and Agreement included a SO_2 Emission Allowance Management Policy ("SEAMP"), which provided for KCPL to sell SO_2 emission allowances in accordance with the initial SO_2 Plan submitted to the KCC

Staff, the Citizen's Utility Ratepayer's Board ("CURB") and other parties in January 2005. While the Regulatory Plan Stipulation and Agreement requires KCPL to record all SO_2 emission allowance sales proceeds as a regulatory liability in Account 254, it further provides that KCPL may recommend an appropriate amortization period for SO_2 emission allowance sales proceeds that have been booked to Account 254 to be included in the 2009 rate case revenue requirement.

Q. In the SEAMP included in the Regulatory Plan Stipulation and Agreement, KCPL agreed to provide KCC Staff and CURB an SO_2 Plan by December 31 each year. Did KCPL submit a new SO_2 Plan prior to December 31, 2006?

A. Yes, we did. We submitted a "2007 SO_2 Plan" to KCC Staff and CURB in December 2006.

Q. Describe how you developed the 2007 SO_2 Plan that KCPL submitted in December 2006.

A. ** [redacted]

[redacted]**

Q. Does the methodology you used to develop the 2007 SO_2 Plan meet the requirements defined in the SEAMP?

A. Yes, I believe it does.

Q. Describe the proposed actions to be taken in 2007 by the 2007 SO_2 Plan.

A. **[redacted]**

Q. Does that Plan expose the Company to any particular risks?

A. **[redacted]**

Q. When is the 2007 SO_2 Plan effective?

A. The SEAMP states that the annual SO_2 Plan will be submitted by December 31 of each calendar year to be effective for the period commencing April 1 of the following year and ending March 31 of the next subsequent year.

Q. How were the proceeds from the 2007 SO_2 Plans reflected in the COS?

A. **[redacted]**

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 Continue the Implementation of Its Regulatory Plan	)))	Docket No. 07-KCPE-____-RTS

AFFIDAVIT OF WM. EDWARD BLUNK

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

William Edward Blunk, appearing before me, affirms and states:

1. My name is William Edward Blunk. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Supervisor, Fuel Planning.

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 forty-two (42) pages and Schedules WEB-1 through WEB-8, 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 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.

W E Blunk
William Edward Blunk

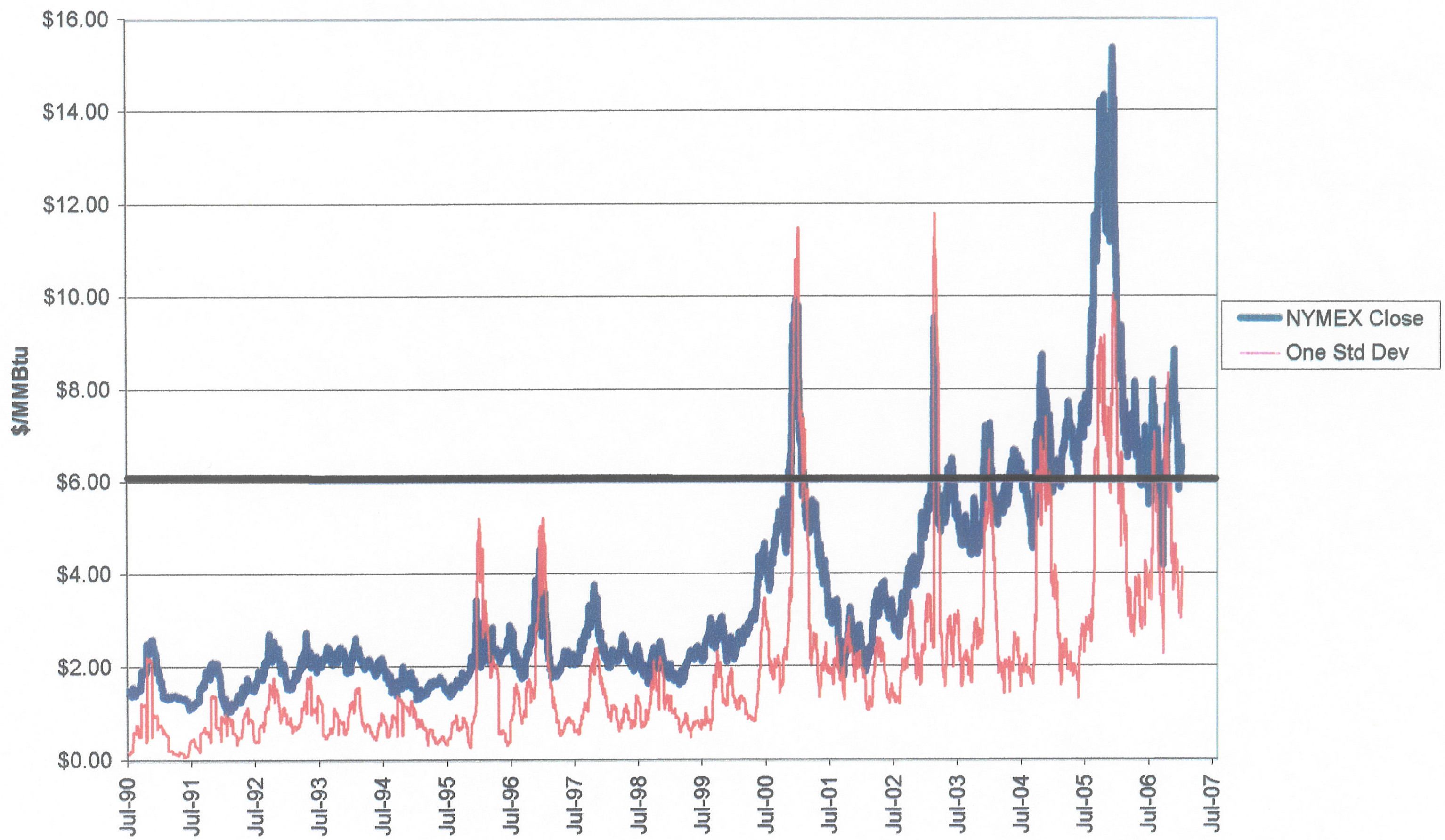
Subscribed and affirmed to before me this 28th day of February 2007.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2011

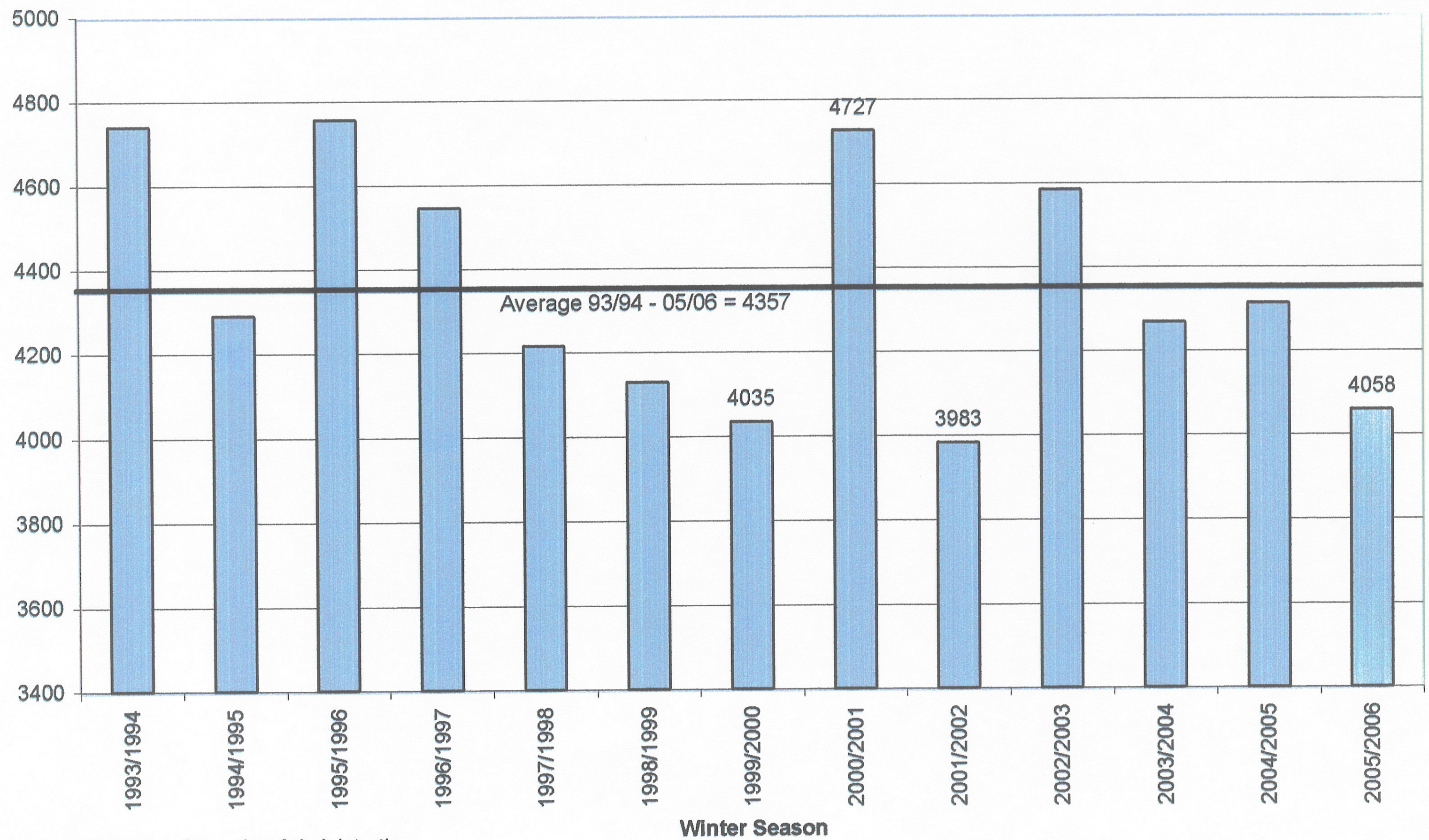
" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

NYMEX Natural Gas
Closing Price vs. One Standard Deviation (20-day volatility)



Schedule WEB-1

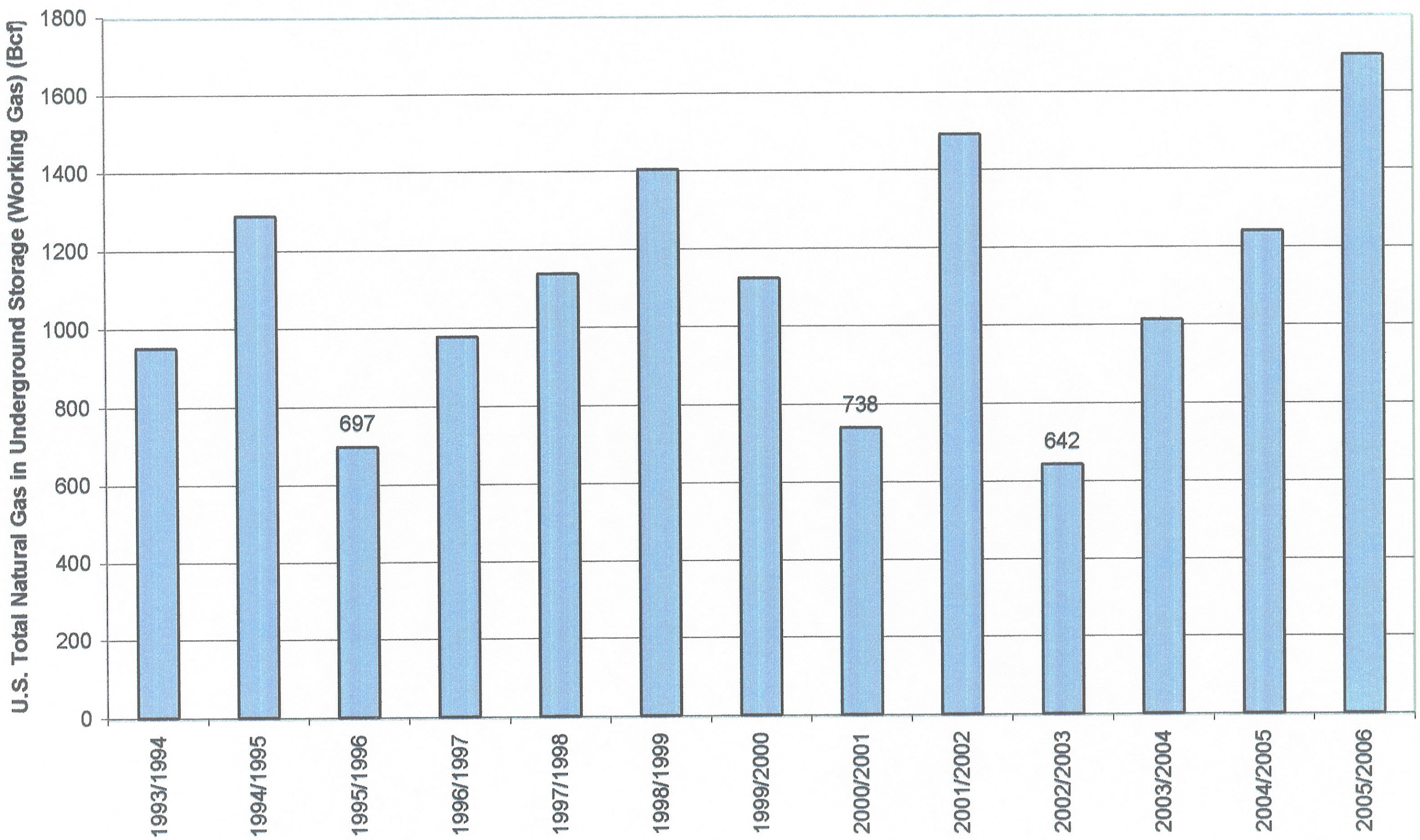
Population Weighted Heating Degree Days



Source: Energy Information Administration

Schedule WEB-2

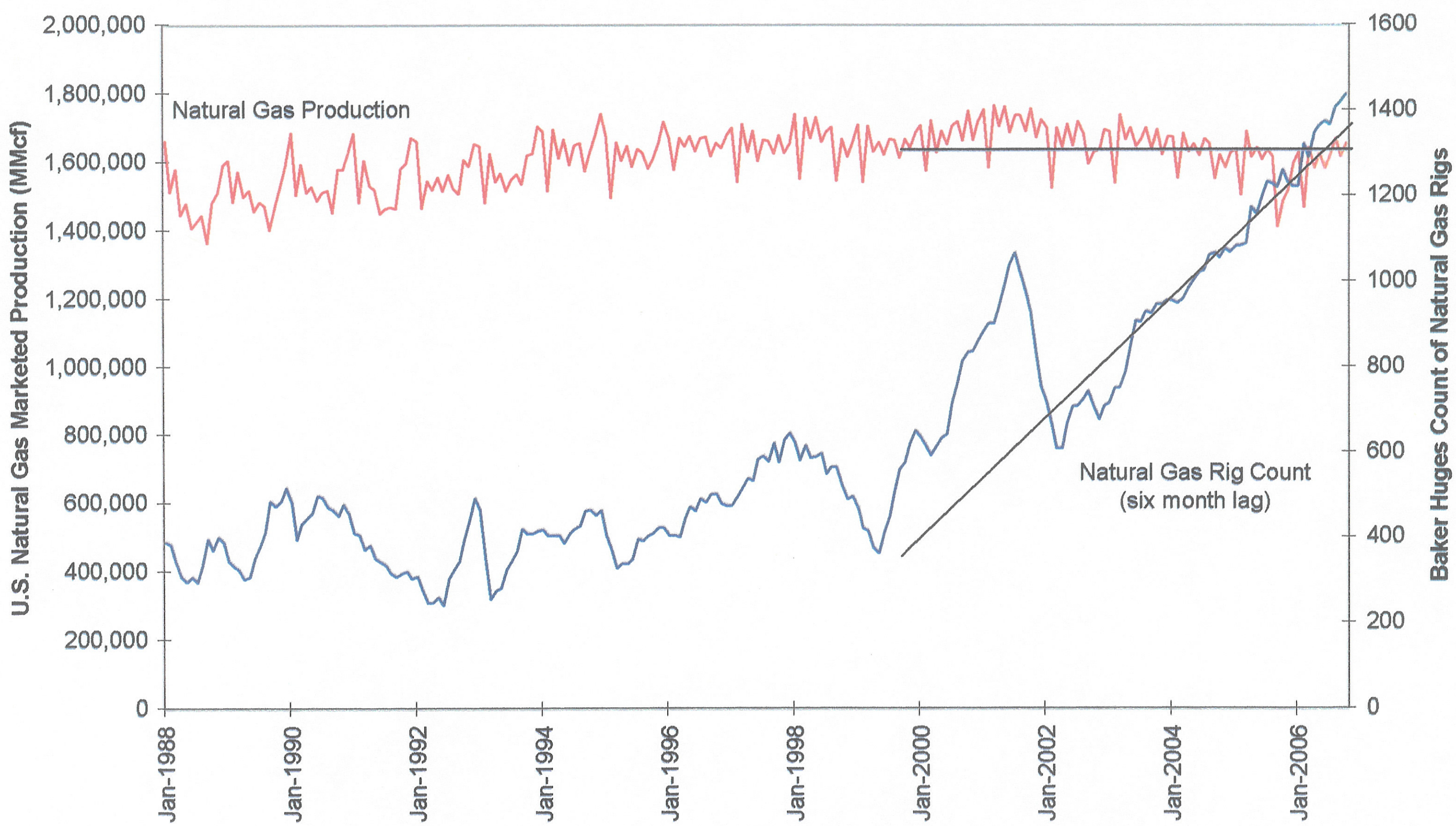
Winter Low Natural Gas Storage



Source: Energy Information Administration

Schedule WEB-3

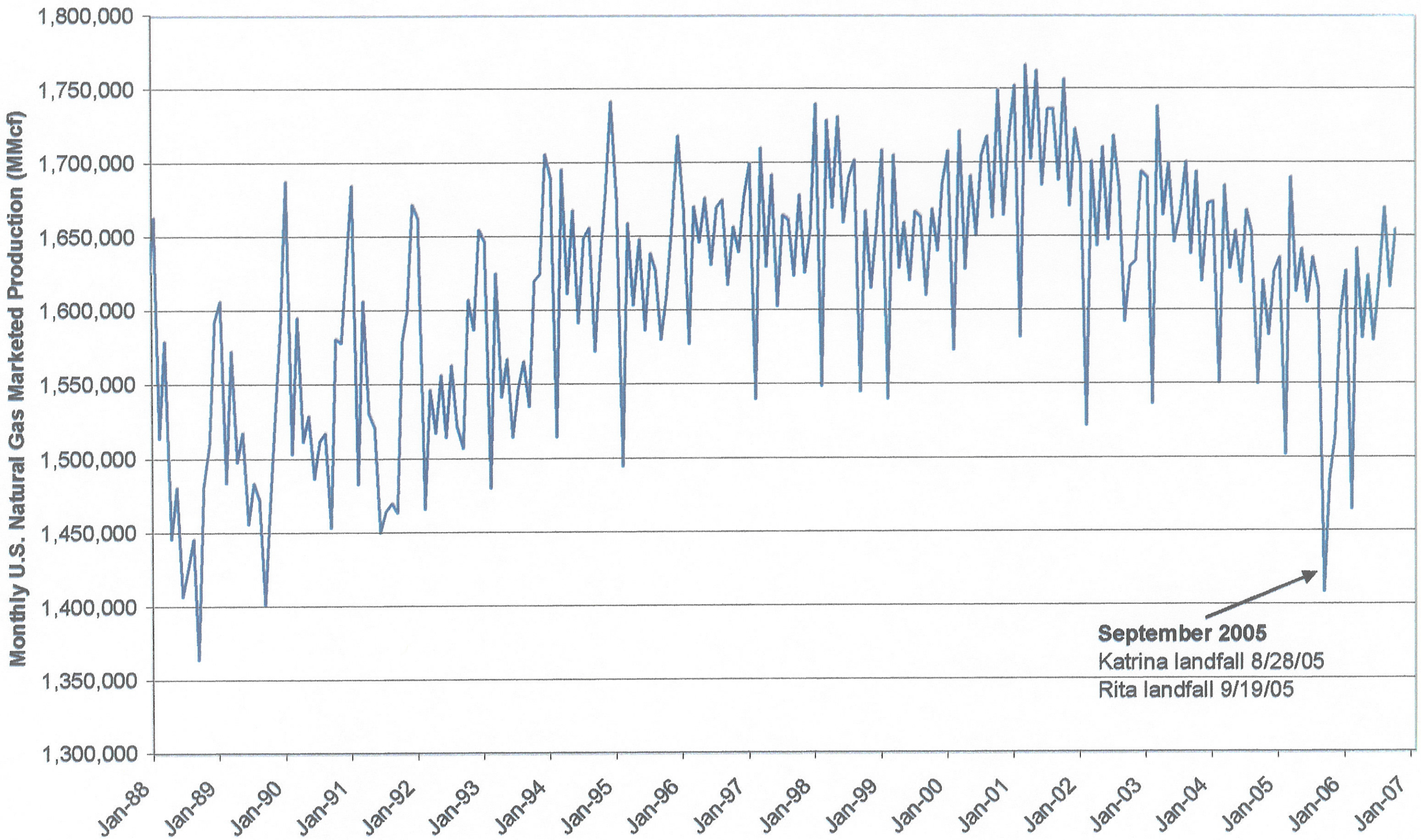
Natural Gas Production vs. Rig Count



Sources: Energy Information Administration and Baker Hughes

Schedule WEB-4

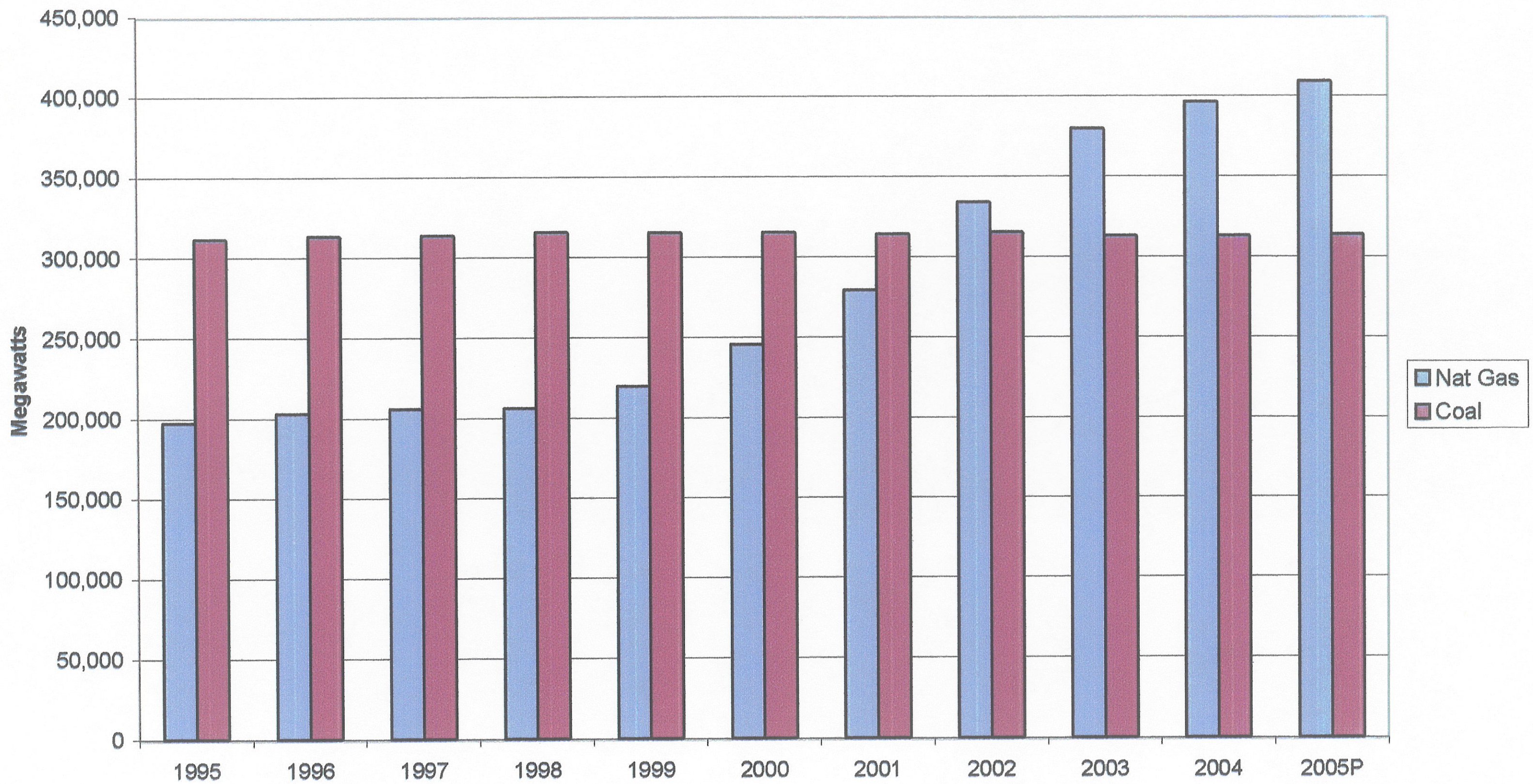
U.S. Natural Gas Marketed Production



Source: Energy Information Administration

Schedule WEB-5

Summer Capacity
Natural Gas vs. Coal



Source: Energy Information Administration

Schedule WEB-6

Coal Stocks in States With >95% PRB Coal vs. Spot Price for 8800 Btu/lb PRB Coal

Sources: Energy Information Administration and *Coal Daily*

Schedule WEB-7

SCHEDULE WEB-8

THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

ORIGINAL FILED UNDER SEAL