Exhibit No.: GMO-10(NP)
Issue: Fuel and Purchased Power
Witness: Burton L. Crawford
Type of Exhibit: Direct Testimony
Sponsoring Party: KCP&L Greater Missouri Operations Company
Case No.: ER-2010-____
Date Testimony Prepared: June 4, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2010-____

Zobrist Exhibit No. 10

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
June 2010

Certain Schedules Attached To This Testimony Designated "(HC)" Have Been Removed Pursuant To 4 CSR 240-2.135.

KCPL Exhibit No. GMO 10 NP
Date 1/31/11 Reporter NS
File No. ER-2010-0356

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

Case No. ER-2010-____

Q: Please state your name and business address.

A: My name is Burton L. Crawford. My business address is 1200 Main, Kansas City, Missouri 64105.

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

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

Q: What are your responsibilities?

A: My responsibilities include managing the Energy Resource Management ("ERM") department. Activities of ERM include resource planning, wholesale energy purchase and sales evaluations, fuel and interchange budgeting, 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 KCP&L, 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 Missouri Public Service Commission or before any other utility regulatory agency?

A: Yes, I have. I provided testimony to KCP&L's Missouri rate cases in Case No. ER-2007-0291 and Case No. ER-2009-0089 and in KCP&L – Greater Missouri Operations

("GMO") rate case No. ER-2009-0090. I also provided testimony to the MPSC in Case No. EO-2006-0142, which pertains to KCP&L's application to join the Southwest Power Pool Regional Transmission Organization. I also provided testimony in Case No. ER-2006-0314, which pertained to KCP&L's application to modify its tariffs to begin implementation of its regulatory plan.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the level of fuel expense, purchased power expense, off-system sales filed in the cost of service and the allocation of GMO's share of Iatan 2 between the former Aquila service territories of Missouri Public Service ("MPS") and St. Joseph Light & Power ("L&P").

I. <u>Energy Price Forecasts</u>

Q: Could you describe how KCP&L Greater Missouri Operations forecasts electricity prices?

A: GMO utilizes the MIDAS™ model, which is similar to other fundamental price forecasting models that are commonly used in the industry. MIDAS™ is provided by Ventyx (Formerly Global Energy). The Transact Analyst™ component of MIDAS™ generates regional prices by modeling power flows within and between various energy markets, transaction areas, North American Electric Reliability Corporation ("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 8,760 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 sources. 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. Ventyx, 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 GMO'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 as difficult to predict its impact on power prices when it is the marginal fuel. Natural gas prices are much more volatile and difficult to predict.

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 BLC2010-1 (HC) presents how closely GMO's power price forecast tracked prices that we observed in the North SPP market. It is a backcast of 2009 using the average spot gas price for each month. It is worth noting that in the modeling GMO 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, intra-month, that would affect our ability to track actual market prices with our backcast. Schedule BLC2010-2 illustrates the monthly volatility of natural gas in 2009. In addition to intra-month gas prices, there is another factor that would influence our backcast versus the actual market. The actual hourly demand data for 2009 is not yet available. Our backcast uses the forecasted hourly demand that is part of the National Database I discussed earlier.

II. Fuel, Purchased Power and Off-System Sales 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. GMO used the MIDAS^{TM} model for its production cost model.

Q: **Please describe the MIDAS^{TM} *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 model 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: GMO'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 GMO witness George M. McCollister. This resulted in revised monthly peak demands and energy requirements, which were input into the MIDAS^{TM} 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 wholesale sale to Western Area Power Administration ("WAPA") has been added to the native load to arrive at the total system requirements. The revenue from this sale and the related costs to serve this load are included in Schedule BLC2010-4 (HC).

Q: Please describe the fuel price normalization.

A: The normalized fuel prices used in the modeling were developed by GMO witness Wm. Edward 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 wholesale energy 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. 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. Schedule BLC2010-3 (HC) contains the maintenance outage assumptions that were 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 December 31, 2010. First, long-term purchase power contract levels were adjusted to reflect the capacity levels that are committed effective December 31, 2010. In addition, projected solar generation resources are included in the modeling under a purchased power arrangement. The generation level and energy price for the solar resource is based on bids received. These modeling assumptions will be updated to reflect actual terms of any PPA reached during the true-up in this case.

Q: How accurate are the results of this modeling?

A: 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. The modeled purchased power results were adjusted to include the net SPP line loss charges. Schedule BLC2010-4 (HC) shows the generation levels by resource type, the purchased power levels and the costs of each. The adjustments are reflected in Schedule JPW2010-

4 LP and Schedule JPW2010-4 MPS, attached to the direct testimony of GMO witness John P. Weisensee.

Q: What method did you use to normalize off-system sales?

A: The same model used to normalize test year fuel and purchased power (MIDAS™) was used to normalize off-system sales. The model was configured to simulate off-system sales for the GMO system based on the same assumptions used to normalize fuel and purchased power costs. The model simulates sales to the wholesale market when there is GMO generation capacity available above that required to meet native load obligations and the market price for power is greater than the available generation capacity's marginal cost. This calculation is made on an hour-by-hour basis for the test period. Normalized off-system sales revenues for this case can by found in Schedule BLC2010-4 (HC). The related generating costs are also included in this Schedule.

Q: How were the results of the modeling allocated between the service territories of MPS and L&P?

A: The modeling results were allocated based upon the methodology included in Schedule 3 to the non-unanimous stipulation and agreement reached in the settlement of MPSC Rate Case No. ER-2009-0090.

III. Iatan 2 Allocation Between MPS and L&P

Q: Please briefly describe the purpose of this portion of your direct testimony.

A: The purpose of this portion of my testimony is to provide support for the allocation of Iatan 2 capacity between the former Aquila service territories of MPS and L&P.

Q: Why is there a need to allocate the Iatan 2 generating capacity between MPS and L&P?

A: While these two former Aquila service territories are owned by the same legal entity, KCP&L Greater Missouri Operations Company, they retain separate rate bases for retail rate making purposes. As such, GMO's share of Iatan 2 needs to be allocated in some form to MPS and L&P.

Q: Please describe the ownership split of Iatan 2.

A: The total net generating capacity of Iatan 2 is approximately 850 MW with 465 MW owned by KCP&L and 153 MW owned by GMO. The remaining 232 MW of capacity is owned by other entities.

Q: Is there an allocation methodology that minimizes the total production cost to GMO retail customers?

A: No. Since the MPS and L&P generating assets are jointly dispatched, the allocation of Iatan 2 capacity between MPS and L&P does not impact generation asset dispatch decisions nor the total production costs to serve GMO retail customers.

Q: What is the basis of the allocation methodology you are recommending?

A: A utility's optimal generating resource mix will be a blend of base load, intermediate, and peaking generation. Base load generation, such as coal-fired generation, is generally designed to run whenever the facility is available as it has relatively low operating costs. Peaking generation, such as a gas-fired combustion turbine, is generally designed to run only during periods of high load requirements as it has a relatively high operating cost, but low installation costs. A utility with a relatively high load factor should generally have more base load resources than one with a low load factor. Since Iatan 2 is a base load resource, I am recommending an allocation methodology based on load factor.

Q: Please describe the load factor based allocation methodology?

A: In brief, the load factor based allocation starts with targeting a base load capacity percentage for each entity (MPS and L&P) equal to the entity's load factor. For example, the MPS load factor is approximately 49.3%. Since the MPS projected 2010 peak load is 1480 MW, the base load capacity target for MPS would be set at 730 MW (1480 MW peak load * 49.3% load factor). Likewise for L&P with a projected peak load of 444 MW and a 59.1% load factor, their base load capacity target would be set at 262 MW (444 MW peak load * 59.1% load factor). The base load capacity target for each entity is then projected through 2025.

The Iatan 2 capacity is then allocated to each entity at the level that minimizes the difference between the base load capacity target and actual base load capacity through 2025. This is accomplished by minimizing the sum of the squared error terms (i.e., the square of the percentage difference between the base load capacity target and actual base load capacity).

Q: What are the results of this load factor based allocation methodology?

A: Allocating 41 MW of Iatan 2 capacity to L&P and 112 MW to MPS minimizes the differences between the base load capacity target and the projected base load capacity. Additional detail on the calculations can be found in Schedule BLC2010-5 (HC). This Schedule is Highly Confidential as it contains market-specific information related to services provided in competition with others.

Q: Did you analyze other allocation methodologies to judge the reasonableness of your load factor based allocation methodology?

A: Yes.

Q: What are these other allocation methodologies?

A: In addition to the proposed load factor based allocation methodology, I calculated both a 4 coincident peak ("4CP") and 12 coincident peak ("12CP") based allocation. These two allocation methodologies are commonly used to allocate production plant between state jurisdictions.

Q: Please describe the results of the 4CP and 12CP allocation methodology for Iatan 2.

A: Using 2008 actual monthly peak load data for MPS and L&P, a 12CP allocation methodology would allocate 39MW to L&P and 114MW to MPS while a 4CP allocation methodology would allocate 35MW to L&P and 118MW to MPS. Both of these peak-based methodologies result in similar results to the proposed load factor based allocation. Additional information on the 12CP and 4CP calculations can be found in Schedule BLC2010-6.

Q: Why have you chosen the load factor based allocation for Iatan 2 over a 4CP or 12 CP based methodology?

A: While the results are fairly similar, I am recommending the load factor based allocation since it takes into account the relative base load capacity needs for each entity, while the 4CP and 12CP based methodologies do not.

IV. ELECTRIC UTILITY FUEL AND PURCHASED POWER COST RECOVERY MECHANSIM

Q: What portions of the Electric Utility Fuel and Purchased Power Cost Recovery Mechanism are you addressing in your testimony?

A: I will address portions of 4 CSR 240-3.161 (3) (Q) and (S). Requirement (Q) addresses heat rate tests results and requirement (S) addresses forecasted environmental investments.

Q: What is the status of the heat rate tests per the requirements in 4 CSR 240-3.161 (3)(Q)?

A: Heat rate tests were completed in 2008 and 2009. Testing has been scheduled for 2010 and 2011. Schedule BLC2010-7 (HC) contains the results of the heat rate tests conducted in 2008 and 2009.

Q: What are the Company's forecasted environmental investments per 4 CSR 240-3.161 (3)(S)?

A: Given the significant uncertainty surrounding future environmental regulations, GMO evaluates the need for future environmental control equipment on an ongoing basis. Currently there are no plans to install any significant equipment such as scrubbers or selective catalytic reduction systems ("SCR") in the next four years.

V. Generating Plant Outage Insurance

Q: Has GMO historically purchased generating plant outage insurance?

A: Yes. GMO has purchased a product since 2004 to serve as a financial hedge against a Sibley 3 outage event.

Q: Please describe how the product has been structured.

A: All purchased contracts have been structured to be eligible to receive payment during on-peak periods where the average price of an indexed market is greater than the contract strike price while there is also a qualifying forced outage event at Sibley 3. Financial risk mitigation has historically been limited to a maximum of $5 million per contract period.

Q: Does GMO plan to continue this insurance, and if not, why?

A: No. This product now provides less risk mitigation value to GMO customers with lower natural gas prices. In only two of the six contract periods has there been an event eligible for recovery. During the two periods with eligible events only one year was it enough to cover the insurance premium paid.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater	)	
Missouri Operations Company to Modify Its	)	Docket No. ER-2010-____
Electric Tariffs to Effectuate a Rate Increase	)	

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 Senior Manager, Energy Resource Management.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of KCP&L Greater Missouri Operations Company consisting of fourteen (14) pages, 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 28th day of May, 2010.

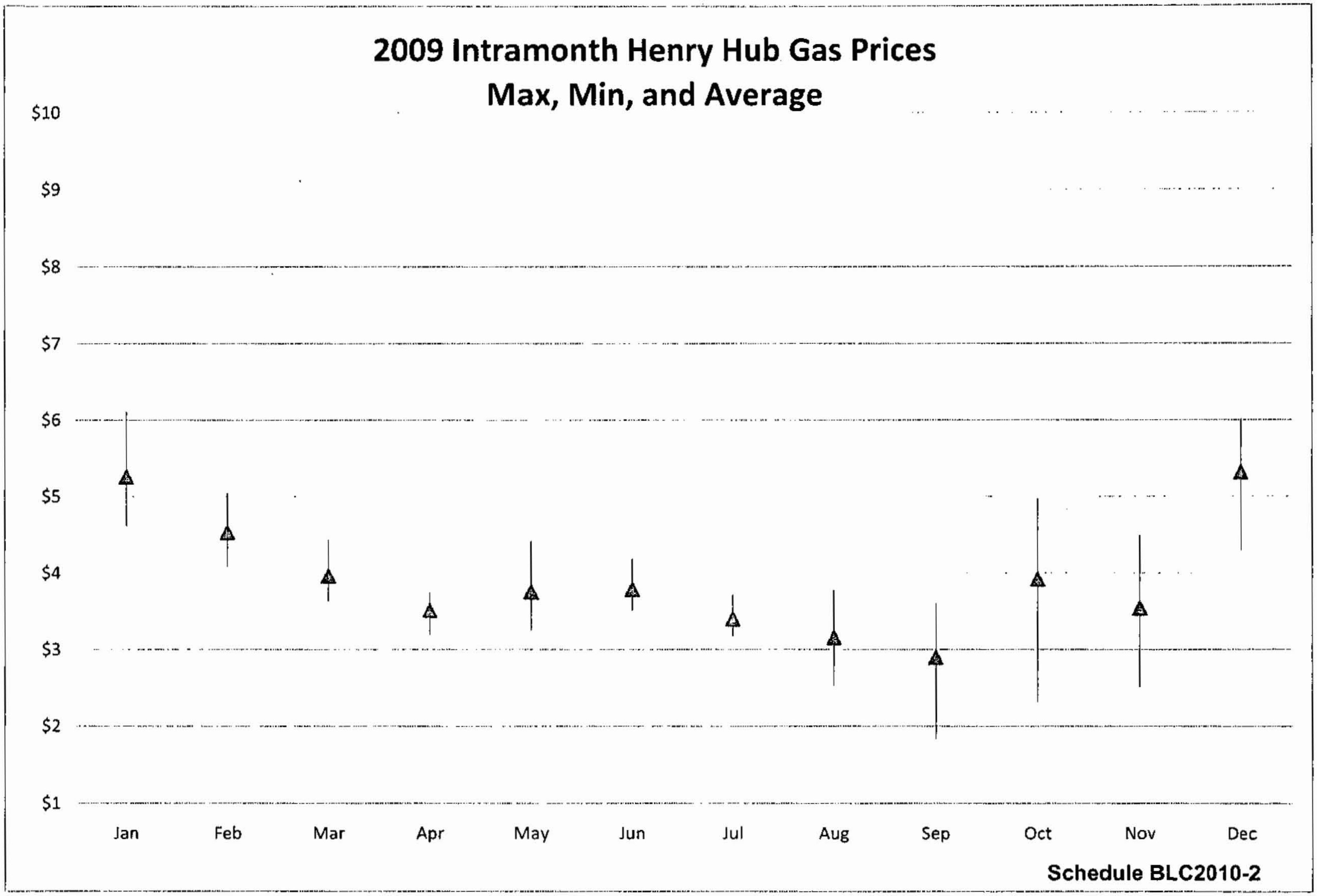
Nicole A. Wehry
Notary Public

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

SCHEDULE BLC2010-1

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC


2009 Intramonth Henry Hub Gas Prices
Max, Min, and Average
$10
$9
$8
$7
$6
$5
$4
$3
$2
$1
Jan
Feb
Mar
Apr
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Schedule BLC2010-2

SCHEDULE BLC2010-3
Through BLC2010-5

THESE DOCUMENTS CONTAIN HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

Iatan 2 Peak Based Allocation Methodologies

4CP BASED ON 2008 ACTUAL PEAKS

	4CP	Allocation	Iatan 2 MW Allocation
MPS	1,354.5	76.8620%	118
SJLP	407.8	23.1380%	35
	1,762.3		153

12CP BASED ON 2008 ACTUALS PEAKS

	12CP	Allocation	Iatan 2 MW Allocation
MPS	1,096.9	74.5441%	114
SJLP	374.6	25.4559%	39
	1,471.5		153

Date	MPS	SJLP
Jan-08	1,056	413
Feb-08	1,048	398
Mar-08	935	351
Apr-08	796	300
May-08	1,024	331
Jun-08	1,310	392
Jul-08	1,443	433
Aug-08	1,478	446
Sep-08	1,187	360
Oct-08	821	310
Nov-08	913	345
Dec-08	1,152	416
Max	1,478	446
Average	1,096.9	374.6

GMO - Monthly Peaks as reported in FERC Form 1 pg 401a

SCHEDULE BLC2010-7

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