Exhibit No.:	
Issues:	Off-system sales pricing; Off-system sales sharing
Witness:	Shawn E. Schukar
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2007-0002
Date Testimony Prepared:	January 29, 2007

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

REBUTTAL TESTIMONY

OF

SHAWN E. SCHUKAR

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
January, 2007

TABLE OF CONTENTS

REBUTTAL
TESTIMONY
OF
SHAWN E. SCHUKAR
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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Shawn E. Schukar. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63166-6149.

Q. Are you the same Mr. Schukar that filed Direct Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony has two principal purposes. First, I outline problems with the analyses conducted by the Staff and certain intervenors of power prices that underlie their testimony related to off-system sales margins. Second, I address discussions contained in certain intervenors' direct testimony related to the sharing of off-system sales margins. Other issues relating to off-system sales raised in the fuel adjustment clause ("FAC")-related testimony filed by others on December 29, 2006 will be addressed by Company witnesses in rebuttal testimony directed toward that December 29, 2006 testimony, which will be filed on February 5, 2007.

II. POWER PRICES UNDERLYING OFF-SYSTEM SALES MARGINS.

Q. What direct testimony do you address relating to this issue?

A. I address the direct testimony of Staff witness Michael S. Proctor, Missouri Industrial Electric Consumers ("MIEC") witness James R. Dauphanais, The Commercial

Group ("TCG") witness Kevin C. Higgins, Missouri Energy Group ("MEG") witness Billie Sue LaConte, and State of Missouri ("State") witness Michael Brosch.

Q. In your direct testimony, you outlined two critical adjustments to natural gas and coal prices necessitated by the impacts of the extraordinary 2005 hurricane season and its aftermath, and the severe rail transportation disruptions that also occurred in 2005. Did any witness who filed direct testimony agree with the need to make those adjustments?

A. Yes. Staff witness Dr. Proctor is quite specific in agreeing that it is necessary to remove those effects from any commodity prices used as a basis for determining an appropriate level of power prices to use in calculating off-system sales margins. With the possible exception of TCG witness Higgins, it appears the other witnesses also agree that 2005 power prices were artificially distorted by these events. I state with the possible exception of Mr. Higgins because on page 20 of his direct testimony he uses a three-year average of power prices -- but without making adjustments for the significant effects of the hurricanes and rail disruptions -- because, in his words, "the use of a three-year average in the first instance is intended to compensate for volatility that may occur in any one year." In essence, Mr. Higgins apparently believes that by using a three-year average he takes into account the impact of the hurricanes and the rail disruptions.

Q. How did other witnesses address the need to adjust power prices to take these effects into account?

A. Dr. Proctor specifically discusses both the abnormal effects of the hurricanes and the rail disruptions on page 3 of his direct testimony. He then concludes that "the objective of my analysis is to remove the effects of these abnormal events on prices and recommend a set of normal prices to be used in this rate case." Dr. Proctor expanded on those comments during his deposition taken on January 12, 2007, wherein he confirmed that he agreed with me that the hurricanes and the rail disruptions affected (*i.e.*, raised) natural gas and coal prices which, in turn, artificially raised power prices. (Proctor Deposition, page 15, lines 1-17).

Mr. Dauphanais, on behalf of MIEC, similarly indicates on page 6 of his direct testimony that "[i]t is clear from Table 1 that December 2005 is an abnormally high pricing period likely brought on by the impact on natural gas supplies from Hurricanes Katrina and Rita." Consequently, Mr. Dauphanais utilized 2006 power price data, presumably to avoid the artificially high prices that would result if unadjusted 2005 data were used. Other intervenor witnesses, such as Mr. Brosch on behalf of the State, also utilized 2006 data – again, presumably to eliminate the impacts of the 2005 hurricanes and rail disruptions.

Q. Do you agree with Mr. Higgins that "the use of the three-year average in the first instance is intended to compensate for the volatility that may occur in any one year"?

A. In part. As I indicated on page 11 of my direct testimony, the use of a three-year average "removes peaks and valleys that might otherwise distort prices." This is important because a year with very hot weather in the Summer and mild weather in the Spring and Fall months may result in exactly the same load on an annualized basis that would be expected during a normal year, but could also yield higher average annual power prices than would likely be observed in a year with normal weather in every season. This occurs because power prices are bounded on the low side by generation costs (i.e., generators will not sell power below the costs incurred to generate the power) but can rise very high if unusual load conditions create scarcity, cause significant transmission constraints, and require the use of very high-cost peaking plants. As a result of this phenomenon, electricity price distributions are skewed to the high side and higher-than-normal loads will typically have higher deviations from average prices than lower-than-normal loads. Because of the price distribution and the effect that warmer-than-normal weather can have, it is important to average prices across several years to address the effects of the non-normal price distribution associated with non-normal weather.

In that sense I agree with Mr. Higgins that a multi-year average should be used. His approach, however, fails to normalize for the very unusual supply disruptions and market conditions that occurred during 2005.

Q. Why doesn't this multi-year averaging address the effects of events like the hurricanes and rail disruptions?

A. Taking a simple three-year average does not address these market disruptions, because the averaging will only help to average out the *normal* volatility that occurs in any given year. It will not address the *abnormal* impact that occurs as a result of extraordinary events like the 2005 hurricanes or the rail disruptions. As can be seen on Schedules SES-5 and SES-6 attached to this testimony, the significant increase in prices associated with the impact of the hurricanes and rail disruption started in June of 2005, and continued through early 2006. As shown, and as also recognized by Dr. Proctor, these types of events had an extraordinary impact on market conditions that cannot be expected to occur every couple years – which means taking a three-year average without further adjustments cannot be used to "normalize" market conditions.

Q What would be the error associated with not making an adjustment to prices for the effect of the rail disruptions or hurricanes?

A. Because the rail disruptions and hurricanes artificially raised coal and natural gas prices, the price of power was also raised artificially. Consequently, if one fails to adjust for the effect of the hurricanes and the rail transportation disruptions, the appropriate amount of off-system sales revenues and off-system sales margins will be overstated because the prices used to determine those revenues and margins will be overstated.

Q. In addition to Mr. Higgins, several other intervenor witnesses utilized prices from 2006 alone. Do you agree that the use of 2006 alone prices is appropriate?

A. No. As indicated previously, it is important to take an average across several years to reduce the potential impact associated with unusual seasonal weather variations and to otherwise remove normal volatility in prices. This is especially true because the average monthly level and seasonal pattern of load used in AmerenUE and Staff's production cost modeling is weather-normalized in order to derive normalized test-year fuel costs and off-system sales margins.

By relying on a single year's power prices, there is a significant risk that the power prices will be significantly overstated (or somewhat understated) vis-à-vis normalized loads. This is especially important, as explained by Dr. Proctor on page 15 of his direct testimony, given the very significant power price spikes observed in July and August of 2006 (due, in part, to hotter than normal weather) coupled with lower than normal prices in September of 2006 (as a result of the significant cooling off in that month). If a single year with such unusual peaks and valleys is used in combination with weather normalized loads, abnormal prices will be matched with normal loads resulting in a distortion of off-system sales margins. Because of the asymmetric distribution of power prices, this will tend to overstate off-system sales revenues and, to an even larger extent, off-system sales margins.

That is precisely why using a wider range of data points (36, for a three-year average, versus just 12 in one year) is necessary. Another reason why relying solely on 2006 is inappropriate is that the 2006 prices for natural gas and electricity were still impacted by the 2005 supply disruptions. For example, a Federal Energy Regulatory Commission report entitled *High Natural Gas Prices: The Basics* (2nd Ed., Feb. 1, 2006), states "Recovery efforts in the Gulf of Mexico have returned almost three-quarters of the supplies shut in by the storm damage both offshore and onshore, in Louisiana." This indicates the continued reduction in supplies of natural gas into 2006 and the consequent continued impact on power prices into 2006 as well. In addition, on page 4 of a Congressional Research Service Report for Congress on Natural Gas Markets in 2006 (which was updated on December 12, 2006), it is stated that "The effects of hurricanes on natural gas production continued to be important during the first quarter of 2006 and persisted through the Summer of 2006." This report also states on page 6 that "The wellhead price for January to March 2006 is the second half of the winter 2005-2005 [sic] heating season, and reflects record setting price levels due to supply disruptions associated with hurricanes Katrina and Rita." Finally, even Dr. Proctor's analysis (*see* Schedule 1.4 to Dr. Proctor's direct testimony) shows the rise of coal prices associated with the rail disruptions that occurred in May 2005, increasing beyond 2005 and through

January 2006. Given Dr. Proctor's analysis associated with relationship between fuel and energy prices, it is clear that early 2006 was impacted by the supply disruption. These continued impacts of the supply disruption into 2006 will have the impact of overstating normal prices and the associated off-system sales margins to the extent others (including Dr. Proctor) utilized 2006 data that includes the distorted data from early 2006.

Q. In addition to the issues associated with utilizing only one year of natural gas and electric prices mentioned above, are there other concerns with the approaches taken by other witnesses in this case?

A. Yes. I address additional concerns associated with the testimonies of Dr. Proctor, Mr. Dauphanais, and Mr. Brosch later in this rebuttal testimony.

Q. Please describe how Dr. Proctor determined the appropriate prices to utilize for natural gas and power.

A. Dr. Proctor used monthly data of power, coal, and gas prices for January 2003 through September 2006 to estimate the relationship between spot fuel (i.e., coal and natural gas) and power prices. First, he performed a regression analysis of the 12 month moving average (12 MMA) of monthly off-peak electricity prices against the 12 MMA of coal dispatch prices (and the square of that 12 MMA of coal dispatch prices). Dr. Proctor also performed a regression analysis of the 12 MMA of monthly on-peak electricity prices against the 12 MMA of natural gas prices. This reflects the recognition that coal-fired generation is typically setting power prices during off-peak periods, while natural gas-fired generation is typically setting power prices during on-peak periods. Based on this estimated relationship between fuel and power prices, Dr. Proctor then used his estimate of normal fuel prices to estimate a normalized level of power prices. If the estimated relationship between fuel and power prices is consistent with the relationship that exists during "normal" conditions, Dr. Proctor's use of that relationship with normal fuel prices would result in "normalized" power prices that no longer reflect the effects of the 2005 supply disruptions.

For off-peak prices, Dr. Proctor developed a normalized coal dispatch price using AmerenUE commodity coal costs as of January 2007 and transportation and SO2 allowance prices from November 2006. He then applied the relationship he determined between coal prices and off-peak power prices to this normalized coal dispatch price to determine the level of off-peak electricity prices. This is the price Staff used in its production cost modeling to estimate the Staff-recommended level of off-system sales revenues.

Similarly, Dr. Proctor used the average of natural gas prices for the period December 2005[1] through November 2006 to determine "normal" gas prices. He then used the estimated relationship between natural gas prices and on-peak power prices to determine the level of normal on-peak power prices.

Dr. Proctor then increased the AmerenUE normalized three-year average power price profile by a constant percentage so that the increased average prices are equal to his estimate of normal annual averages of on-peak and off-peak power prices. Staff then used this adjusted power price profile in its production cost model to estimate the Staff-recommended level of normal fuel prices and off-system sales revenues.[2]

Q. Do you agree with Dr. Proctor's estimate of normalized power prices?

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[1] As discussed below, this distorts gas prices because of the huge run-up in gas prices still being experienced at this time due to the effects of the 2005 hurricanes and thus overstates power prices and off-system sales margins.

[2] See Mr. Finnell's rebuttal testimony for his discussion of the inconsistent use by Staff of load and price profiles from different periods.

A. No. Based upon his 12 MMA regressions, Dr. Proctor came up with normalized off- and on-peak power prices that, as I will show, are significantly overstated.

Q. You mentioned that Dr. Proctor performed an analysis to determine the relationship between the coal prices and off-peak power prices. Do you agree that there is a relationship between coal prices and off-peak power prices?

A. Yes. However, I do not agree with the specific relationship Dr. Proctor developed in his analysis.

Q. Do you also agree that there is a relationship between natural gas prices and on-peak power prices?

A. Yes. However, Dr. Proctor's analysis overstates normalized on-peak prices because he incorrectly assumed that the relationship between power and gas prices is the same for all seasons of the year. As I will also show, his normalized on-peak power prices are also overstated because his estimate of normalized natural gas prices is too high.

Q. Do you have any specific concerns with the regression analysis that Dr. Proctor performed to estimate the relationship between fuel and power prices?

A. Yes, I have several concerns with the analysis Dr. Proctor performed. My concerns relate both to the underlying data that he used and to how that data was manipulated for the purpose of his regression analysis. I would not recommend using Dr. Proctor's approach because I believe the 2005 supply disruptions will make it difficult to estimate the "normal" relationship between fuel and power prices. But if Dr. Proctor's approach was going to be used in whole or in part, it would be absolutely essential to improve the underlying data as well as the regression analysis itself. As I will show, his current model overstates normal electricity prices, which leads to a significantly overstated Staff estimate of off-system sales revenues and margins.

Q. Please describe the concerns that you have with the regression analyses performed by Dr. Proctor.

A. The first concern I have with Dr. Proctor's regression analyses is that Dr. Proctor utilized AmerenUE-supplied power and natural gas price data that, as he used it in his specific analysis, results in overstated normalized power prices. The natural gas and power pricing information that underlies Dr. Proctor's analysis includes pricing information from January 2003 through September 2006, including the time period before the start of the MISO Day 2 Energy Markets on April 1, 2005. The power price information for the period *prior* to the start of the MISO Energy Markets reflected the *actual* (volume weighted) prices realized by AmerenUE for the bilateral sales transactions actually made by AmerenUE. Thus, these pre-MISO Energy Market prices correctly reflect limitations associated with system congestion and the effect of the cost of losses which depended on the delivery location.

The price data used for the period *after* the start of the MISO Energy Markets, however, contained the energy only price that is set for MISO as a whole. This data did not include the MISO locational congestion and loss components and consequently does not represent the price that AmerenUE could actually realize at the locations of its power plants. This incorrectly overstates off-system sales margins.

Q. Why does this create flaws in Dr. Proctor's analysis?

A. Dr. Proctor's analysis spans 18 months of MISO Day 2 operations. This makes it very important to use the correct MISO prices as they apply to AmerenUE's plants. As Dr. Proctor recognized during his deposition, the correct MISO price that AmerenUE receives for off-system sales is the MISO Locational Marginal Price ("LMP") at the location of its power plants ("Gen LMP"). (Proctor Deposition, page 94, lines 14-25; page 95, lines 1-9). Because the Gen LMP at AmerenUE plants is a few dollars lower than the MISO-wide energy LMP, his use of the MISO-wide energy-only LMP distorts the power-fuel price relationship he estimates with his regression analyses and leads to inaccurate estimates of normal power prices. The use of Gen LMP data for AmerenUE's plants is needed to puts all 45 months of data on an equal footing; that is, a footing that is reflective of prices *actually* realized by AmerenUE.

Q. Where did Dr. Proctor obtain his data?

A. Dr. Proctor obtained the data from the Company, but I believe it is likely that Staff accidentally overlooked the fact that the data did not include the congestion and loss components of the LMP once the MISO Energy Markets started. The Company was clear about this in the data request response wherein this data was provided to Staff, but that fact could still have been overlooked.

Q. Why did you use only the energy prices in your determination of the appropriate market electricity prices? Wouldn't this cause the same kind of distortion in your market prices?

A. No. I only relied on nine months of data during MISO Day 2 operations and did not use this data to perform Dr. Proctor's type of regression analyses. I used a three-year average with adjustments for the effect of the 2005 hurricanes and the rail transportation disruptions. Had I included the effect of losses and congestion (i.e., not used just the energy-only piece post-MISO Energy Markets), this would have tended to lower my overall average even further and would not have been as conservative an approach. However, since Dr. Proctor makes a substantial upward adjustment of my prices based on a regression analysis that spans a much larger period of the MISO Day 2 energy markets, it is important that he uses a consistent set of pricing data for the entire period contained in his analysis. As I will show, not doing so results in significantly overstated estimates of normalized market energy prices.

Q. Do you have a recommendation regarding how this concern should be addressed?

A. Yes. To address this issue in Dr. Proctor's analysis, it is necessary to apply the analysis using AmerenUE Gen LMP data for the entire MISO Day 2 period. In particular, I recommend using the average of AmerenUE baseload coal generator LMPs (i.e., the base load units at Labadie, Meramec, Sioux, and Rush Island), which are the plants from which most off-system sales are made.

Q. Do you also have concerns with the natural gas prices that were utilized to perform the regression analysis performed by Dr. Proctor?

A. Yes. Dr. Proctor utilized natural gas prices that only represented the price on the first day of each month. Since Dr. Proctor was trying to develop the relationship between natural gas prices and on-peak electricity prices, it is more appropriate to use daily gas price data for the entire month, because that price is more closely aligned with the underlying on-peak electricity prices. Dr. Proctor himself testified in deposition that the average price of gas over an entire month is more representative than using prices for *only one day* within a given month. (Proctor Deposition, page 109, lines 20-23, page 110, lines 4-7). The main concern with utilizing only one day of gas prices each month is that, if the particular day was unusually hot or cold, or if there was some kind of supply or other market disruption on that day, the gas price and the resulting relationship to on-peak power prices would be distorted. If one relies on all days in each month, the gas prices are more consistent with the power prices, which similarly reflect a full month's worth of data.

Q. Do you have a recommendation for the appropriate gas price data to utilize for the analysis?

A. Yes. Because AmerenUE does not purchase gas every day throughout the year, the gas prices reported as Platts Gas Daily Midpoint for Chicago Large End Users daily gas price provide the daily gas prices that would have been actually experienced by AmerenUE. AmerenUE's gas supplies are closely tied to these regional prices. In fact, I examined the Platts gas prices and found that they were consistent with the AmerenUE single-day prices used by Dr. Proctor in his analysis – confirming that Platts provides a good measure of the natural gas prices faced by AmerenUE (as well as other utilities in the region). The results of this comparison are presented in Schedule SES-7, and show that the last trading day from the previous month in Platt's dataset is consistent with the price used by Dr. Proctor. Utilization of this daily price data will make Dr. Proctor's analysis more accurately portray the actual relationship between natural gas and on-peak electricity prices.

Q. Do you have additional concerns with the regression analysis performed by Dr. Proctor?

A. Yes. Dr. Proctor utilized a 12 MMA of fuel and electricity prices to determine the relationship between the fuel and annual on-peak and off-peak electricity prices. Dr. Proctor then applied the relationship that he determines from the regression of the 12 MMA data to estimate a normal level of annual electricity prices, which he then uses to adjust AmerenUE's hourly price data.

A key problem with this approach is that taking the 12-month moving average of the available price data will cause statistical problems that can distort interpretation of the regression results,[3] which will overstate the explanatory power of the regression, and create the *illusion* of a good fit, as typically measured by the "R-squared" value. For example, Dr. Proctor illustrates to the strength of his off-peak regression model by pointing to an R-squared of over 97%, but running the same regression on the actual monthly data (rather than taking a monthly average first and ignoring the readily-available data for each day within each of the 12 months) cuts that statistic nearly in half and exposes the true variability in the relationship between power and fuel prices. In other words, the strength of the relationship is actually much less than Dr. Proctor's analyses would suggest.

Dr. Proctor's use of a 12-month moving average also incorrectly assumes that the relationship between power and fuel prices is the same throughout the year. This loss of the seasonal relationship between gas prices and on-peak electricity prices is particularly important for on-peak prices. As it turns out, the relationship between the natural gas prices and the on-peak electricity prices are different in the Summer months and the non-Summer months. This is because natural gas peaking units are on the margin (i.e., set the power price) much more often during Summer months than during the non-

[3] For example, *see* Zellner and Montmarquette (1971, *Review of Economics and Statistics*).

Summer months and the gas plants that are on the margin during the summer tend to be the least efficient peaking units. A different relationship in the summer and non-Summer months results in different adjustments to the hourly prices during Summer and non-Summer months. Because AmerenUE's off-system sales are much lower during the Summer months when prices are high (because native loads are also high during the Summer), ignoring the seasonal variation in the relationship between peak power prices and gas prices creates a systemic upward bias in Staff's estimates of off-system sales and revenues.

Q. Are you presenting an analysis that corrects for these problems in Dr. Proctor's regression analysis?

A. Yes. While I do not recommend use of Dr. Proctor's analysis for the reasons I discuss herein, I had Dr. Proctor's regression analysis duplicated and then corrected for the problem areas I have just discussed. The corrected analyses reflect the following changes to Dr. Proctor's original analysis:

1. Utilize the appropriate Gen LMP data at the AmerenUE baseload generating stations for MISO Day 2 operations;

2. Utilize a complete set of daily natural gas prices (for the Platts Gas Daily Midpoint for Chicago Large End User prices);

3. Perform the off-peak regression based on the available monthly coal price data and monthly off-peak power price data;

4. Perform two on-peak regressions based on daily gas prices and on-peak power prices to handle the seasonal differences in the relationship between gas and on-peak power prices: (a) one regression for the Summer months (June-August); and (b) one for the rest of the year;

5. Perform regressions with the most up-to-date data available, including price data through December 31, 2006; and

6. Remove the “square of coal prices” variable that Dr. Proctor added to his off-peak regression which distorts the fuel-power price relationship, because the value of this variable was driven by a single monthly data point, a clear “outlier” that the analysis should not rely upon.

To check the accuracy and reasonableness of both Dr. Proctor's original analysis and the improved analysis I present in this testimony, I have applied regression results to actual 2006 fuel prices to see if the results can actually estimate 2006 electricity prices.

Q. Please describe in more detail your modifications to Dr. Proctor’s off-peak analysis.

A. Schedule SES-8 plots the regression lines for various off-peak models against the actual data, and illustrate that Dr. Proctor's off-peak model does not provide as good of a fit as he suggested

The first page of this schedule shows Dr. Proctor's 12 MMAs and his off-peak regression results, based on the correct power prices (AmerenUE Gen LMPs) and data through December 2006. Each dot represents a 12-month average and the line is Dr. Proctor’s estimated relationship between coal and off-peak power prices. (The three circled data points reflect the three months of prices that could be added to Dr. Proctor’s data set). This chart clearly documents that Dr. Proctor’s relationship very poorly “fits” the fuel and power price data, particularly during the last 15 months (i.e., starting in the 4th quarter of 2005). For example, the data point labeled “Avg(Jan06-Dec06)” represents the 12-month average of coal and off-peak power prices during calendar year 2006. It shows that the 12 MMA of actual coal prices of $1.71/MMBtu resulted in a 12 MMA of actual power price of about $29.30/MWh.

In contrast, based on Dr. Proctor’s relationship, he estimates that the actual 12-month average coal dispatch price of $1.71/MMBtu would have resulted in a power price of $34.57/MWh, which overstates actual 2006 off-peak prices by $5.30/MWh. Importantly, this chart also shows that Dr. Proctor’s relationship unreasonably suggests that at his much lower normalized coal price of $1.39/MMBtu, power prices would even be higher than they actually were in 2006, despite the fact Dr. Proctor’s normalized coal dispatch prices are significantly below actual 2006 average prices. (The fact that normalized coal dispatch prices are below the 2006 average is supported by Dr. Proctor’s testimony and his Schedule 1.4, consistent with the fact that spot coal prices have dropped considerably from an all-time January 2006 high.)

The second page of this schedule explains why Dr. Proctor's claimed good fit is really only an illusion. This page shows the actual monthly price data behind Dr. Proctor’s 12 MMAs. It documents that the illusory strong fit from the previous page is largely a result of averaging out the variation in the actual data. This chart also shows that January 2006 is a clear outlier: a high coal price of $2.61/MMBtu is observed at a relatively low off-peak price. It is this point that results in the “curved” relationship that Dr. Proctor has measured. Without this single point (which is just one point out of 48 data points), these data clearly illustrate that only a linear relationship between coal and off-peak power prices can be justified statistically. The comparison of the improved linear relationship with Dr. Proctor’s original relationship for a normalized coal dispatch price of $1.39/MMBtu also shows that Dr. Proctor overstated normalized off-peak power prices.

Q. Did you request any other tests to compare Dr. Proctor’s off-peak model to an improved specification?

A. Yes. Table 1 below shows a comparison of the estimated off-peak prices for 2006 based on Dr. Proctor’s relationship versus the improved relationship for actual 2006 average coal dispatch price, which was approximately $1.70/MMBtu. The first row shows that this dispatch price was actually associated with an annual average off-peak price of $29.26. The second row of the table shows that Dr. Proctor's model estimates an off-peak price that is over $5.00 above what was actually observed in 2006. In contrast, the last row shows that the improved model (which I described above) over-estimates 2006 average off-peak prices by only $3.63. This is still a significant overstatement, demonstrating that Dr. Proctor’s analysis continues to be biased, but that the improved model is nevertheless a marked improvement over Dr. Proctor’s original estimate. Actual market conditions in 2006 show that Dr. Proctor’s model is not capturing the best relationship between coal and off-peak electricity prices.

Table 1
Predictions of Off-Peak Electricity Prices versus 2006 Actual Conditions

Source	Coal Price	Off-Peak UE Price	Extent of 2006 Overprediction
[1]	[2]	[3]	[4]
2006 actual coal and off-peak electricity prices	$1.71	$29.26	$0.00
Proctor model at actual coal prices	$1.71	$34.57	$5.30
Improved Proctor model (monthly, updated through Dec. 06, using UE Gen LMPs) at actual coal prices	$1.71	$32.89	$3.63

Notes:
[1]: Improved Proctor model excludes January 2006 outlier.
[2]: $1.71 reflects average 2006 monthly coal prices.
[3]: Actual prices reflect average of AmerenUE Day-Ahead Baseload Gen LMPs during 2006 off-peak hours. Predicted price calculated by applying regression results to AmerenUE 3-year adjusted average prices.
[4]: For predictions using actual coal prices, = [3] - $29.26.

Q. What does this comparison of estimated and actual off-peak prices mean with respect to what a correct value for off-peak power prices should be?

A. These comparisons show that Dr. Proctor's recommended normalized off-peak power price of $30.63/MWh is clearly overstated, potentially by a very significant amount. Given that the normalized coal dispatch price of $1.39 is well below the actual 2006 average coal dispatch price of $1.71, the *normalized* off-peak power price certainly should be *below* (not above) the actual 2006 average of off-peak power price. As Dr. Proctor noted, my recommendation of normalized off-peak power prices averages $26.41/MWh, which is $2.85/MWh or 9.8% less than the 2006 average. This lower level of off-peak prices is considerably more consistent with the positive relationship of coal and power prices, and the fact that normalized coal dispatch prices of $1.39 are over 18.7% lower than the actual 2006 dispatch prices of $1.71.

Q. Have you calculated the results of the off-peak estimate utilizing the normalized price of $1.39 per MMBtu and the improved Proctor model?

A. Yes. The results of the improved model with the normalized coal prices results in a $28.42 off-peak price which is $0.84 or 2.9% below the 2006 actual off-peak price.

Q. Please describe in more detail your review and modifications of Dr. Proctor's on-peak analysis.

A. As discussed in the context of Dr. Proctor's off-peak regressions, his use of moving 12 MMAs creates the illusion of a better "fit" than is actually the case. Schedule SES-9 plots actual daily natural gas and on-peak power prices for the Summer and non-Summer periods for the entire 2003-06 data set. The two charts also show the relationship Dr. Proctor estimated based on his 12 MMAs as a black thin line. Finally, these two charts show the relationship that best fits the on-peak power vs. natural gas price relationship during the Summer and non-Summer months. This shows that Dr. Proctor's analysis *understates* the slope of the on-peak power and natural gas price relationship during the Summer (page 1), while it *overstates* that relationship during the rest of the year. In other words, Dr. Proctor's failure to differentiate the different seasonal relationships tends to *understate* on-peak prices during the Summer and *overstate* prices during the non-Summer months.

According to Mr. Finnell's model results, only approximately 21% of off-system sales during peak hours occur during the Summer months. However, because most of AmerenUE's off-system sales during peak hours occur during non-Summer months, Dr. Proctor's overstated peak prices during these months as the result of his averaging across all seasons also results in an upwardly-biased Staff estimate of off-system sales revenues and margins.

Q. Are there any other reasons why Dr. Proctor's normalized on-peak prices are too high?

A. Yes. Dr. Proctor arrives at his $7/MMBtu recommendation of normalized gas prices by taking a 12-month average from December 2005 through November 2006. This will overstate normal gas prices because it includes December 2005, which was still greatly affected by the hurricane-related disruptions as even Dr. Proctor recognized during his deposition. (Proctor Deposition, page 43, lines 7-15). In fact, December 2005 had the highest average monthly natural gas prices in the aftermath of the hurricanes. Simply updating natural gas prices through December 2006, reduces Dr. Proctor's 12-month average from $7/MMBtu (12 months ending November 2006) to $6.58/MMBtu (12 months ending December 2006). I believe Dr. Proctor's normalized gas prices should, at a minimum, be updated to reflect these lower full-year averages. In fact, Dr. Proctor indicates that he has no problem updating his 12 MMAs to include December 2006 (which would have the effect of dropping December 2005). (Proctor Deposition, pages 80-81). Without this bare-minimum adjustment, the hurricane effects would not be removed, which Dr. Proctor agrees should be the objective, and off-system sales margins will be distorted (i.e., on these facts, overstated). (Proctor Deposition, page 45, lines 9-21). I believe, however, that even this gas price is still too high because the 12-month average includes January and February 2006, which were still noticeably affected by the hurricane disruptions, as discussed earlier.

Q. Did you request other tests be performed to assess the reasonableness of Dr. Proctor's on-peak model and the improved seasonal specification for updated normal natural gas prices that exclude December 2005 natural gas prices?

A. Yes. Table 2 shows a comparison of the estimated on-peak prices for 2006 based on the actual average natural gas prices for 2006. Actual average natural gas prices for 2006 were $6.40/MMBtu during the Summer and $6.65 in the other months.

The first row of Table 2 shows that during the Summer 2006, on-peak power prices at the location of AmerenUE's generating plants were $66.03/MWh. However, during peak hours in non-Summer months, the on-peak prices averaged only $44.62. Considering that only 21% of AmerenUE's off-system sales are made during the Summer months, these prices yield a weighted average on-peak price of $49.14. The second row of Table 2 shows that applying Dr. Proctor's average annual relationship even to the lower updated average 2006 gas prices model, would yield an estimate of normalized average annual power prices of $50.78, which is $1.65 above what was actually observed in 2006. Note that during non-Summer months, when AmerenUE makes the most off-system sales, Dr. Proctor's model overstates actual 2006 prices by $6.64/MWh or 14.9%.

Finally, the last row of Table 2 shows that the estimates of on-peak prices based on the updated and improved seasonal model of the on-peak vs. natural gas price relationship (again when used with actual 2006 natural gas prices), comes considerably closer to actual power prices. Both the estimates for Summer and non-Summer peak prices are significantly better than the estimates based on Dr. Proctor's original model. Note, however, that peak prices during the non-Summer months are still overstated by $2.13/MWh or 4.8%. The weighted average estimate for the year is $0.49/MWh below

2006 actuals, but I am comfortable with this discrepancy because the Summer of 2006 was an atypically hot, higher priced time period.

Table 2

Predictions of On-Peak Electricity Prices versus Actual, Forward, and Forecast Data

Source	Gas Price	UE On-Peak Electric Price						
		Summer (Jun. - Aug.)	Other Months	Approx. OSS Weighted Avg.	Ratio of Summer to Non-Summer Prices	Differences Relative to 2006: Summer (Jun. - Aug.)	Differences Relative to 2006: Other Months	Differences Relative to 2006: Approx. OSS Weighted Avg.
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
2006 on-peak electricity prices	-	$66.03	$44.62	$49.14	148%	$0.00	$0.00	$0.00
Proctor model at actual gas prices	$6.40 for summer, $6.65 for other months	$49.00	$51.26	$50.78	96%	-$17.03	$6.64	$1.65
Improved Proctor model (daily, updated through Dec. 06, using UE Gen LMPs and daily gas prices) at actual gas prices	$6.40 for summer, $6.65 for other months	$55.70	$46.76	$48.64	119%	-$10.33	$2.13	-$0.49

Notes:
[2]: $6.40 and $6.65 reflect 2006 actual calendar year seasonal gas prices.
[3] - [4]: Predicted price calculated by applying regression results to AmerenUE 3-year adjusted average prices for relevant time period.
[5]: OSS-Weighted average of [3] and [4]. OSS weights based on hourly OSS volumes produced by Mr. Finnell in response to DR 0145
[6]: = [3] / [4].
[7]: = [3] - $66.03.
[8]: = [4] - $44.62.
[9]: = [5] - $49.14.

Q. What does this comparison of estimated and actual on-peak prices mean with respect to what a correct value for on-peak power prices should be?

A. Once again, these comparisons show that Dr. Proctor's recommended normalized prices are significantly overstated. The on-peak power prices are particularly overstated during non-Summer months, when AmerenUE makes most of its off-system sales. Table 2 shows that Dr. Proctor's on-peak prices are overstated even when his $7/MMBtu normalized gas price is replaced with the updated normalized gas prices that do not include the extraordinarily high December 2005 gas prices. The comparison with a 2006 actual average price of $49.14 shows that his current $54.51/MWh recommendation for the normalized on-peak power prices (which is based on the inflated $7/MMBtu gas prices), overstates on-peak prices by roughly $5/MWh, which is quite substantial.

Q. Because of the issues associated with Dr. Proctor's model and the narrow use of fuel price data, do you recommend the use of Dr. Proctor's regression analysis?

A. No. Even with the corrections I outlined I do not recommend relying on Dr. Proctor's approach because, as shown in my discussions of Tables 1 and 2, there is substantial evidence that even these improved and corrected results continue to *overstate* reasonable estimates of on-peak and off-peak power prices. This would, of course, also result in overstated off-system sales revenues. However, if the Commission does utilize an approach similar to Dr. Proctor's, it would be absolutely necessary to make the corrections I previously outlined. If those corrections are made, one would have to use the still-over estimated but lower off-peak power price of $28.42/MWh and the still-over estimated but lower on-peak power prices (Summer and non-Summer) of $55.70 (Summer) and $46.76 (non-Summer), respectively, in modeling off-system sales. As discussed in AmerenUE witness Timothy D. Finnell's rebuttal testimony, simply using these corrected prices would drop Dr. Proctor's estimated off-system sales margins by approximately $34 million.[4]

Q. Do you have any other concerns with Dr. Proctor's direct testimony?

[4] This ignores phantom margins that others would argue should be included for phantom energy from Electric Energy, Inc. modeled to make off-system sales in Staff's production cost modeling in this case. The Electric Energy, Inc. issues in this case are addressed by others. If phantom margins were included, correcting Dr. Proctor's prices would reduce margins by approximately $50 million.

A. Only that my adjustments to Dr. Proctor's analysis are conservative in that they reflect an assumption that all off-system sales are made in the MISO day ahead markets. In reality, a portion of AmerenUE's off-system sales will be in the MISO real time market. For AmerenUE's baseload generators, day-ahead prices are systematically higher than real-time prices. Table 3 illustrates the impact of making some of the off-system sales at the real-time price by comparing day-ahead actual prices to a weighted-average that assumes 90% of off-system sales are made in the day-ahead market and 10% are made in the real-time market. On average, average annual realized prices would be $0.20/MWh below day-ahead prices using this assumed weighting and, during Summer peak hours, the average prices would be $0.75/MWh lower.

Table 3

Impact of Utilizing Properly Weighted Day-Ahead And Real-Time LMP Averages

Time Period (2006 Actuals) [1]	AmerenUE Baseload LMPs Day-Ahead [2]	Real-Time [3]	90% Day-Ahead 10% Real-Time Average [4]	Impact of Proper Weighting of Prices [5]=[4] - [2]
All	38.93	36.93	38.73	-0.20
Peak	50.10	46.68	49.76	-0.34
Off-Peak	29.26	28.49	29.19	-0.08
Summer Peak	66.03	58.53	65.28	-0.75
Non-Summer Peak	44.62	42.60	44.42	-0.20

Q. How does Mr. Dauphanais determine the electricity prices to utilize to determine off-system sales?

A. Mr. Dauphanais suggests setting the electricity price equal to the average price for the period of January 2006 through December 2006.

Q. Outside of your earlier comments relating to the appropriateness of utilizing only one year of data, do you have other concerns with what Mr. Dauphanais presented?

A. Yes. Mr. Dauphanais is correct in that he utilized the MISO Gen LMP associated with the AmerenUE power plants. However it would be more appropriate to utilize the average of the LMPs at the AmerenUE generator nodes that typically provide off-system sales. It would also be necessary to utilize the day-ahead and real-time LMPs at these generator locations at the ratio that AmerenUE normally sells into the day ahead and real time markets.

In addition, it is inappropriate to use an average that only includes eleven months of the year, especially when the month that is not utilized is from a non-Summer (lower price) period. Leaving out an off-peak month means Mr. Dauphanais' average price is overstated. At the minimum, Mr. Dauphanais should also utilize the December 2006 prices to develop a 12 month average price.

Q. How does the correct use of a 12-month average Gen LMP change Mr. Dauphanais results?

A. Mr. Dauphanais' average price for the MERAMEC1 pricing node for the period January 06 – November 06 was $50.98 on-peak and $29.10 off-peak.[5] If the prices are corrected to reflect a full calendar year, the average prices for the period January 06 – December 06 would be $49.95 on-peak and $29.00 off-peak for Meramec1. The fact that some of AmerenUE's sales are made at real time prices further decreases

[5] Incidentally, Mr. Dauphanais defined his peak and off-peak hours with respect to the Eastern time zone. I convert the LMP data from MISO's use of Eastern time to Central time zone prior to assigning each hour to the peak and off-peak periods.

the average realized price since day ahead prices averaged about $1.84 per MWh more than the real time prices at this node.

Q. In his testimony, Mr. Dauphanais also looked at the Cinergy Day-Ahead price for the same period. Would the Cinergy Day-Ahead price be appropriate to use as the price that AmerenUE recognizes for off-system sales?

A. No. While the prices at the Cinergy hub are correlated with the prices at the AmerenUE generator nodes, the Cinergy Day Ahead prices averaged $1.51 more than average AmerenUE generator node prices in 2006. The use of the Cinergy price creates a basis differential error that can be avoided if actual AmerenUE generator node prices (which reflect actual realizations by AmerenUE) are used. In addition, the use of the Cinergy Day Ahead price again incorrectly assumes that AmerenUE has the ability to achieve all its off-system sales at day ahead prices, while ignoring that a portion of AmerenUE's sales are at the generally somewhat lower real-time prices.

Q. Mr. Dauphanais also compares the forward price curve at the Cinergy Hub to the historical averages of LMP at the MERAMEC1 node and AmerenUE's adjusted on-peak prices. He then concludes that the market expects higher wholesale electricity prices. Do you agree with this assessment?

A. No. First of all, the day-ahead Cinergy Hub price averaged $2.08 more than the average AmerenUE generator node price in 2006 during on-peak hours. Thus, Mr. Dauphanais' forward curve analysis overstates prices simply because of the fact that he is using the Cinergy Hub prices rather the AmerenUE generator prices. In addition, forward prices reflect more than just the average expected spot market price. Forward contracts for electricity are in essence a combination of the average expected spot prices for the delivered price and location and a hedge against spot price volatility, which results in a risk premium or discount associated with the contract. After large jumps in the market prices like the price spikes that were seen in 2005 resulting from the hurricanes and rail disruptions, forward prices will tend to have a significant built-in risk premium, which means forward prices will exceed the expected spot prices.

Schedule SES-10 compares forward prices and realized spot prices at the Cinergy hub. This chart shows that between February and June of 2006, forward prices for the following six months exceeded actual spot prices observed in the following six months by approximately $6.00 on average. This implies that recent forward prices include an average $6.00 risk premium. The on-peak forward price for 2007 at Cinergy Hub for the last five days traded in December was $55.01. If we adjust the $55.01 for the $2.08 AmerenUE-Cinergy on-peak basis differential and the $6.00 on-peak risk premium, it would suggest that the appropriately adjusted expected average day-ahead spot price for 2007 is only $46.93, which is close to the $46.01 weighted on-peak energy price I sponsored in my direct testimony.

Q. Mr. Dauphanais concludes on page 10 of his direct testimony that "there is a significant amount of information that supports there being significantly higher spot market prices for wholesale electricity than those used by AmerenUE." Do you agree?

A. No. As I have shown, the data that Mr. Dauphanais claims to show a much higher spot market price simply does not reflect the prices that AmerenUE could achieve in making off-system sales. In addition, Mr. Dauphanais seems to leap to the conclusion that, just because AmerenUE is seeing an increase in fuel cost, the balance of the market is seeing the same cost increases, resulting in increased energy prices. While there is a strong relationship between the *overall* market price of fuel and power prices, that relationship does not necessarily exist between AmerenUE's price of fuel and power prices. Since contracts for fuel tend to have relatively long terms, changes in fuel price from one year to the next for one company may not reflect the market price of fuel. A three or five year contract could easily be below or above the current market prices depending on when the contract was consummated.

Schedule SES-11 illustrates this concept using actual, regional coal spot prices from the recent past. For instance, assume a company had entered into a three-year fixed coal contract at point A on the Schedule. Spot fuel prices increased significantly between points A and B on the chart, and the market price of power reflects that rising trend in fuel costs. However, the company with the three-year contract did not see those corresponding fuel price hikes. Between points B and C, the market prices of fuel came down steadily. During this same time period, the company would be renegotiating rates for another fixed contract, and those rates may be higher than the original contract. Mr. Dauphanais would argue that if the new contract price at point C is higher than the contract price at point A, power prices that were determined based on the fuel prices associated with point B should be adjusted upward, even though the underlying market price of fuel was higher at point B. In fact, this approach would be improper, as the market prices for coal that ultimately influence the market price of power are on the decline.

Q. Mr. Dauphanais recommends, based on his assertion that there is evidence that supports higher electricity prices, that AmerenUE should rerun its

production cost simulations using spot prices for coal, fuel oil, natural gas and wholesale electricity that are consistent with the 2006 year. Do you agree?

A. While I agree that the coal, fuel oil, natural gas, and wholesale electricity prices that are utilized when running a production cost simulation should be consistent to obtain the most accurate results, I have shown why the use of the data that Mr. Dauphanais suggests is not appropriate. The prices that AmerenUE utilized for the modeling were consistent with electricity prices that I have shown to be reasonable.

Q. Mr. Dauphanais claims that AmerenUE dismisses forward market prices. Is that true?

A. No, not at all. First, we understand that reliance on forward prices is not appropriate for the purpose of ratemaking in Missouri. But just as important, what we indicated is that forward market prices are not necessarily a good predictor of the actual spot prices that will be experienced at the generation nodes that are relevant to determining off-system sales margins. While we do believe that forward prices give an indication of future price levels, the market price also includes a risk premium that can change over time. As I noted above, this risk premium would generally be expected to be largest after periods that have significant price disruptions such as the disruptions that occurred in 2005. As a result, the use of the forward prices can cause an inaccurate forecast of prices that AmerenUE could actually be expected to achieve.

Q. Mr. Dauphanais indicates on page 13 that he disagrees with AmerenUE's position that it would be appropriate to reduce the liquidated damages price by 5-10% because forward prices do not consistently understate or overstate spot prices. Do you agree?

A. No. The 5-10% decrease was not related to the liquidated damages provisions of the contracts, but the fact that a forward contract is for the same amount of deliveries during every hour of the contract period. Because AmerenUE only sells power after the native load requirements have been met, the amount that is available to be sold each hour of a period can vary significantly and can in fact be zero. Moreover, AmerenUE will tend to have less to sell in the high load, high price periods and more to sell in the low load, low price periods. As a result of the variation of the amount that AmerenUE has to sell in each hour, AmerenUE will not be able to realize the same price as the typical forward contract. Given this dynamic, I would expect that AmerenUE would be able to realize on average 5-10% less than the price it would receive if it was able sell its output at the fixed hourly amounts required in forward contracts. This is yet another reason why reliance on forward prices to try to predict AmerenUE average off-system sales margins can overstate those margins.

Q. Do you have any additional comments regarding Mr. Dauphanais' proposal to set the market prices equal to the average of 2006 prices?

A. Yes. The use of the market prices from only one year also leads to the inaccuracies previously discussed, due to weather impacts and other market conditions that would tend to be averaged out if a multi-year average, such as the adjusted three-year average used by the Company, were used instead. Relying on a single year is highly unlikely to represent normal market conditions.

Q. How does State witness Mr. Brosch suggest electricity prices should be set for the determination of off-system sales revenues?

A. Mr. Brosch suggests using the average MISO energy prices for a single year -- 2006.

Q. Do you have concerns with Mr. Brosch's approach?

A. Yes. Mr. Brosch's approach reflects many of the same flaws that I discussed relating to Dr. Proctor's and Mr. Dauphanais' methodologies. First, the recommended prices reflect only average MISO energy prices and consequently fail to accurately reflect the prices that AmerenUE can actually realize for off-system sales at its generating stations. To correct this, Mr. Brosch would need to utilize the Gen LMPs from the units that are expected to make off-system sales. (These Gen LMP prices have been significantly below the MISO energy-only prices.) Second, Mr. Brosch recommends using a single year with abnormally high prices in the Summer and unusually low prices in September (Proctor direct testimony, p. 15) -- which creates the upwardly-skewed average price that I discussed earlier.

Q. Based on your review of the different proposals put forth by Dr. Proctor and the other intervenors, have you changed your recommendation associated with the appropriate price for electricity to be used in determining off-system sales?

A. No. I have pointed out many of the concerns associated with the different proposals set forth by these parties. As I have shown, there is significant evidence that Dr. Proctor's approach, even based on corrected prices and an improved model, continues to overstate market prices. The other witnesses all have one issue in common that I am very concerned about: the fact that their recommendations are based on information from only one year, 2006, with abnormally high Summer prices combined with low September prices, which can have the distorting effect I discussed. In addition, the 2006 price data still reflects some of the lingering effects of the hurricane and rail disruptions that occurred in 2005. Both the price distortions from the above-average Summer prices and low Fall prices, and the aftermath of 2005 supply disruptions that continued into early 2006, would cause 2006 prices based on a single year's data to be higher than normal.

Since it is difficult to estimate by how much that serves to inflate 2006 prices above normal levels, I believe the prices that I sponsored in my direct testimony are still the most appropriate -- they solve the weather-related variation problem by using a multi-year average and also remove the effects of the 2005 hurricanes and rail disruptions. While I believe that the prices I sponsored remain the most appropriate prices upon which to base off-system sales margins, I have also provided important and necessary corrections to the methodologies employed by the other witnesses. However, as pointed out, even with these corrections, the available evidence strongly suggests that the resulting prices remain overstated, which will result in overstated estimates of achievable off-system sales margins.

III. OFF-SYSTEM SALES SHARING MECHANISM.

Q. What direct testimony do you address relating to the sharing of off-system sales margins?

A. I address the December 15, 2006 testimony of three witnesses, as follows: Maurice Brubaker testifying for MIEC, Kevin Higgins testifying for TCG, Billie Sue LaConte for MEG, Ryan Kind of the Office of the Public Counsel ("OPC"), and Michael Brosch testifying for the State.

Q. Does the December 15 testimony of any of these witnesses undermine the sound bases for examining the off-system sales margin sharing mechanism presented by the Company?

A. No. As I indicated in my direct testimony, off-system sales are a very large, potentially volatile, and highly uncertain element of the Company's business. Consequently, off-system sales inject significant uncertainty into whether base rates will be set at appropriate levels that ultimately turn out to be fair for the Company and customers alike. The sharing of off-system sales margins is an effective method that could be utilized to address some of the uncertainty inherent in setting an appropriate level of off-system sales margins in base rates while also continuing to provide an effective incentive for the utility to optimize plant performance and minimize its generation cost. The sharing structure I outlined in my direct testimony was provided to initiate discussions associated with addressing this uncertainty. While the Company has not formally proposed adoption of the outlined mechanism, I continue to believe that, if utilized, it would be fair to both customers and the Company.

Q. Mr. Brubaker, on page 14 of his December 15 testimony, indicates that since $180[6] million is AmerenUE's best estimate of its OSS margin, sharing 20% of the off-system sales margin between $120 million and $180 million has a built-in bias against customers. Is he correct?

A. No. Absent a sharing mechanism, AmerenUE's shareholders would be fully exposed to any shortfall in off-system sales margins below the $183 million base level

[6] Using actual data for the last three months of the test year in this case (as reflected in my Supplemental Direct Testimony filed on September 29, 2006), my recommended level of off-system sales margins is actually $183 million, versus the $180 million reflected in my direct testimony filed on July 7, 2006, which was based on budgeted data for the last three months of the test year.

but would also benefit from all off-system sales margins above the $183 million base level (assuming $183 million will be the level of off-system sales margins in base rates). The structure that I outlined would mitigate some of the downside risk for AmerenUE's shareholders by providing what would in effect be partial insurance against a shortfall in margins to the extent margins fell between $121 million and $183 million. In that event, AmerenUE shareholders would bear 20% of the lower margins with $12.6 million being the largest amount of lost margin that the shareholders would bear, assuming margins of at least $120 million. This would leave customers to bear between $12.6 million and $63 million if actual margins ranged between $120 and $183 million. In exchange for this partial mitigation of the Company's downside risk, customers gain a significant potential upside that is not available under traditional regulation. That is, the structure provides customers with 50% of the margins between $183 million and $360 million for a potential customer benefit of up to $75 million and above. Consequently, if there is a bias in the tradeoff between what the Company stands to gain if off-system sales margins are less than expected (e.g., up to $63 million in downside mitigation) and what customers stand to gain if such margins are greater than expected (e.g., $75 million), that bias could favor AmerenUE's customers.

Q. Mr. Brubaker also states on page 13 of his December 15 testimony that he disagrees with the basic philosophy of sharing because customers have paid for the assets that generate off-system sales and, consequently, should receive 100% of the OSS margins. What is your response?

A. Mr. Brubaker seems to misunderstand the purpose of the sharing proposal. Under the traditional regulatory treatment customers receive "100%" of the off-system sales margin by including in base rates an off-system sales credit equal to a normalized estimate of off-system sales margins. If (due to uncertainties in market prices, load or plant availability) actual margins are higher or lower than the off-system sales margins reflected in base rates, which is likely,[7] customers bear none of these deviations – neither on the upside nor on the downside. Under the sharing alternative, customers would be provided with a share of the upside opportunities in return for also sharing an equivalent amount of downside risk. However, just because deviations from the normalized off-system sales margins are shared between customers and shareholders (instead of being 100% allocated to shareholders), does not mean customers do not receive the appropriate "benefit of OSS margins."

Q. Mr. Brosch indicates on pages 13-14 of his December 15 testimony that he does not believe that there should be any sharing of off-system sales margins, but that a tracking mechanism would be more appropriate. Mr. Kind similarly proposes a tracking mechanism in his December 15 testimony. Do you agree?

A. No, I strongly disagree for at least two reasons. First, Messrs. Brosch and Kind seem to forget or possibly ignore that there are offsetting effects on the revenues that AmerenUE realizes or may realize from native load customers and the revenues from off-system sales. When native load sales are higher than the normalized sales utilized to determine base rates, the level of off-system sales goes down, and vice versa. Since the margins earned on off-system sales are generally below the margins earned on retail sales to native load customers, the use of a tracker mechanism for off-system sales would

[7] Dr. Proctor agrees that we will fail to accurately predict the actual margins over the next three to four years. (Proctor Deposition, p. 37, l. 4-12).

actually put the utility at greater risk than the risk it faces under existing ratemaking practice.

The second reason why a tracker on off-system sales would be poor public policy is that AmerenUE's proposed treatment of off-system sales margins provides the Company with strong incentives to maintain high plant performance and availability – particularly in the context of a fuel adjustment clause. Tracking off-system sales margins would entirely eliminate this incentive. This "incentives" point will be addressed in greater detail in the Company's FAC-related rebuttal testimonies, which are to be filed on February 5, 2007.

Q. Mr. Brosch also indicates that there has been no showing that the shareholders of the Company bear any costs or risks associated with the generating facilities or other resources involved in making off-system sales. Do you agree with Mr. Brosch's position?

A. No, not at all. One of the issues associated with this case relates to the Taum Sauk plant and how the physical loss of that plant will be handled in light of AmerenUE's commitment to avoid negative rate impacts in this case due to the loss of the plant. The Taum Sauk plant supported both native load and off-system sales. Consequently, it is also a good example of why AmerenUE's shareholders were bearing significant risk associated with Taum Sauk – and are bearing significant risks related to the performance of any of its generating facilities. This is because almost any plant outage, including plants that are mostly used to serve native load, would immediately reduce off-system sales volumes, which would not only impose outage-related costs but also reduce off-system sales revenues (possibly well below the level reflected in base rates) which thereby directly affects AmerenUE's profits. In addition, AmerenUE also bears the risk that actual operating and maintenance costs will be higher than the level of operating and maintenance costs included in base rates. Since O&M costs support plant operations and the sales from these plants, it is clear that AmerenUE shareholders also bear O&M risks.

Q. Mr. Higgins included a table, Table KCH-1, in his December 15 testimony which purports to show the impact to customers of the sharing mechanism outlined in your direct testimony. Is Mr. Higgens' table accurate?

A. No. Mr. Higgins' table is incorrect for all values on the sharing grid ranging from $0 to $120 million. Under the Company's proposed sharing grid, customers are held harmless if off-system sales margins fall below $120 million. This means the risk of off-system sales margins falling below $120 million is borne entirely by shareholders. This means, compared to the Company's proposed traditional treatment of including a $183 million off-system sales margins in base rates (i.e., without sharing), the downside impact of the sharing proposal on customers is limited to the range of zero to $63 million. As discussed, however, and as shown in Mr. Higgins' table, customers' upside potential under the sharing alternative is considerable, possibly exceeding $100 million compared to the proposed traditional treatment.

A. On page 25 of his December 15 testimony, Mr. Higgins also outlines a different sharing mechanism which calls for a 50/50 split of off-system sales margin deviations from the $183 million base line. What is your reaction to Mr. Higgins' proposal?

A. The purpose of presenting an off-system margin sharing mechanism was to show that there were options that could help offset the risk associated with getting the off-system sales margin incorrect, while also maintaining good incentives to optimize plant availability and costs. I believe that Mr. Higgins' proposal, which would split both positive and negative deviations from the $183 million baseline is an alternative sharing structure that could provide similar benefits as long as the sharing of downside risk can actually be accomplished. Based on Mr. Higgins' proposal, for example, of a $60 million reduction of off-system sales margins below the $183 million baseline, customers would bear $30 million. This, would, of course require that this amount could actually be collected in customers' rates – which will be feasible only if an FAC is implemented. Without an FAC, it is unclear how, if at all, AmerenUE would be able to obtain its $30 million share of the $60 million shortfall. While a positive sharing amount could be distributed to customers as a bill credit, it would require an FAC or similar rate adjustment mechanism to collect through retail rates any negative sharing amount. To avoid the creation of significant bias against shareholders through implementation of sharing mechanism in the absence of an FAC consequently requires reducing the off-system sales margins credit in base rates below the $183 million base line amount, but provides customers sharing credits for all or most of the off-system sales margins between that lower threshold and the $183 base line amount. This, of course, is precisely the type of sharing mechanism I have outlined as a potential alternative to the traditional treatment of off-system sales margins.

Q. MEG witness LaConte indicates in her December 15 testimony that she believes that the risk-reward profile of the sharing structure you outlined in your direct testimony is biased in favor of AmerenUE. Do you agree?

A. No. As I indicated earlier in discussing a similar point made by Mr. Higgins, I do not believe this bias exists. Based on Ms. LaConte's testimony, she believes the widest possible range for off-system sales margins is $120 million to $360 million. If there was no sharing at all, the customer benefit from off-system sales would be fixed at $183 million, with no upside. Under the sharing mechanism I presented, customers have unlimited upside opportunities, possibly gaining in excess of $100 million beyond the $183 million base line, while being fully protected on the downside through a $120 million guaranteed off-system sales margin. At the 80% sharing between the $120 million floor and the $183 million base line, the worst customers would do is a $63 million disadvantage compared to the traditional off-system sales treatment. I believe that the potential risk and rewards of this sharing proposal are balanced appropriately.

Q. Ms. LaConte also proposes an alternate sharing structure on page 16 of her December 15 testimony. Do you have any concerns with the sharing structure she proposed?

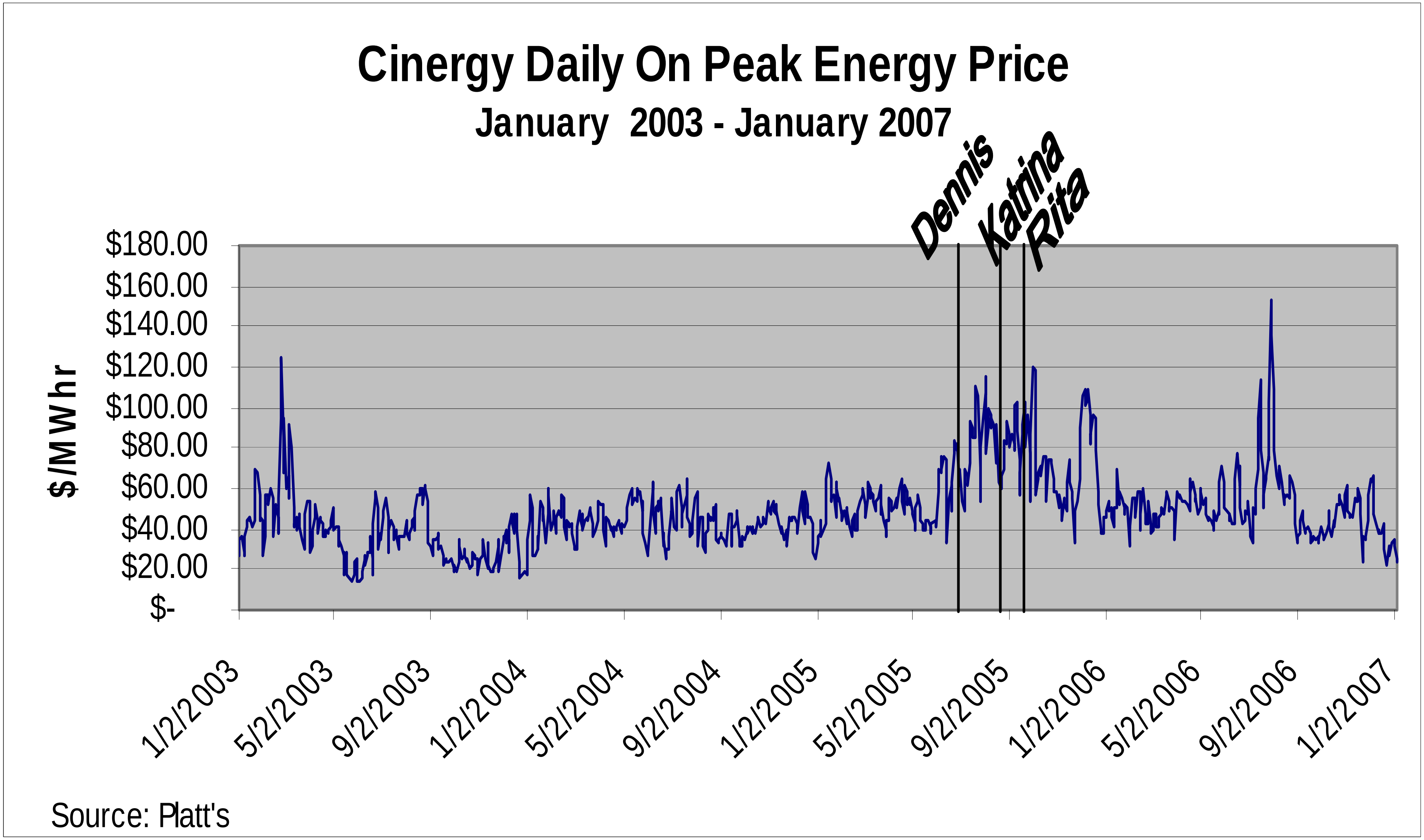
A. Yes. Ms. LaConte's alternative is an entirely one-sided proposal under which AmerenUE would receive very little of the upside (e.g., only 20% of off-system sales margins in excess of the $183 million baseline) without receiving *any* downside protection (i.e., being 100% exposed to any variations below the $183 million baseline).

If AmerenUE did not have a sharing mechanism, the Company would be at risk for off-system sales margins falling below the normalized baseline of off-system sales margins and would receive the full benefit of off-system sales margins that are above that level. It is a virtual certainty that the normalized level that is reflected in base rates will not be realized exactly. As Dr. Proctor acknowledged in his deposition, no matter what "number" is chosen as the off-system sales credit to base rates, whether using traditional ratemaking or a sharing mechanism, actual off-system sales margins will differ over the next few years. (Proctor Deposition, page 37, lines 4-12). Given these normal variations of actual off-system sales margins above and below the $183 million expected baseline amount, Ms. LaConte's proposal can only harm the Company – it would simply take money away from shareholders and result in effective rates that would be below AmerenUE's cost of service.

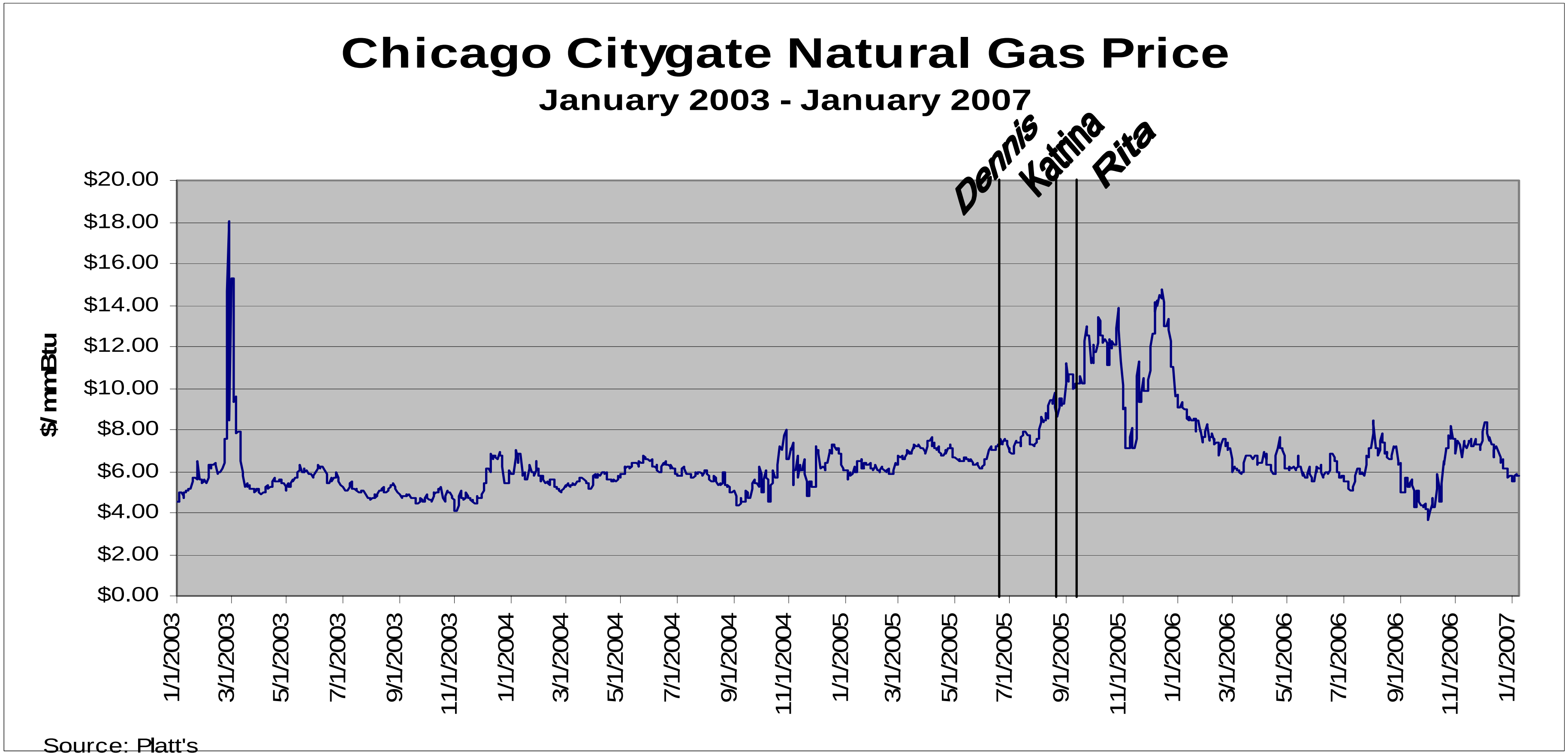
In short, it is not a fair and unbiased sharing mechanism, as customers only see upside with no downside risk whatsoever. If customers are to obtain this upside benefit, then they should either receive a lower off-system sales credit in base rates (e.g., the $120 million I suggested) or bear comparable downside risks in return (e.g., through symmetric sharing of both upside and downside risks as proposed by Mr. Higgins). The sharing grid I have outlined in my direct testimony more appropriately balances risks and benefits between customer and the Company.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

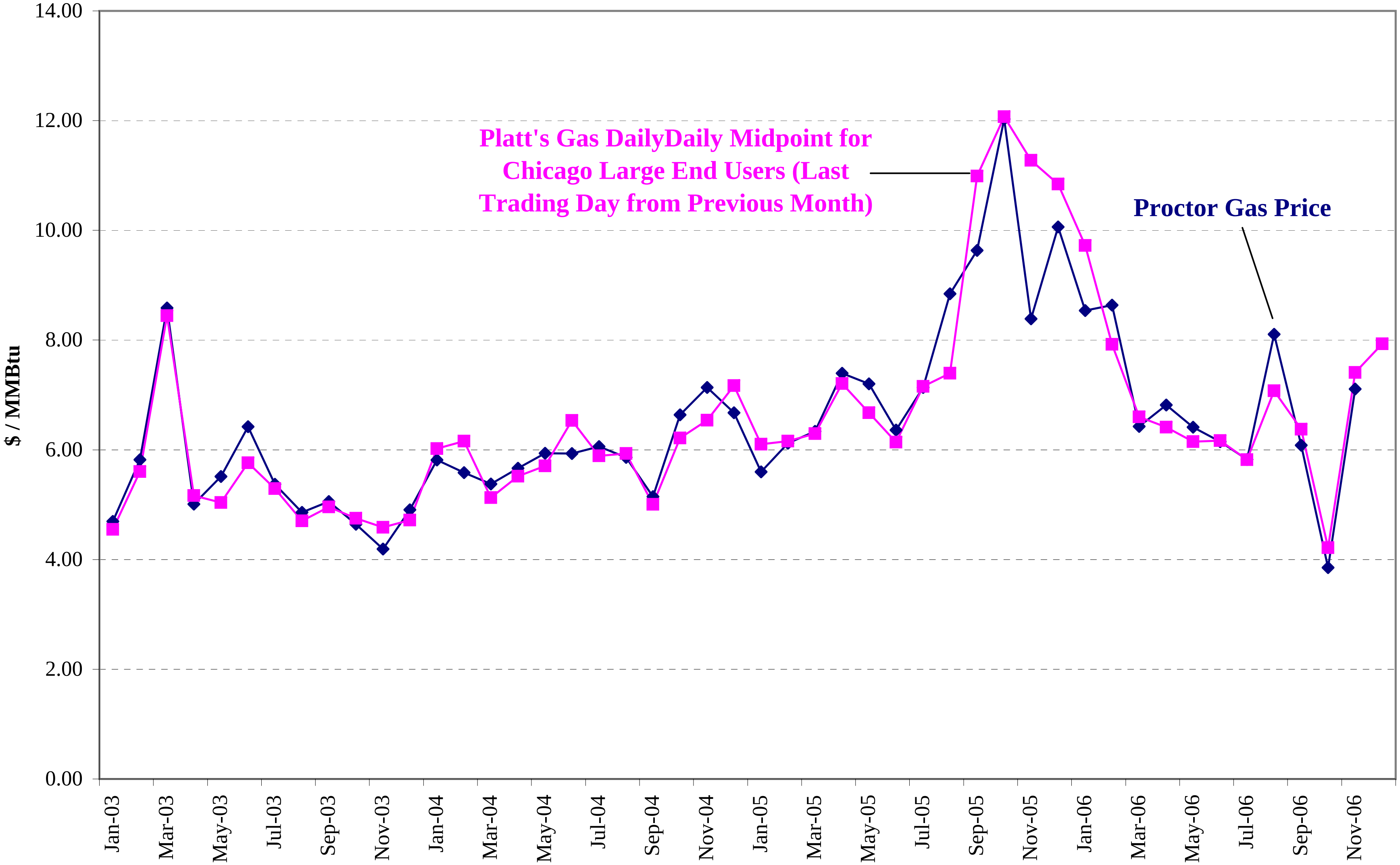


Schedule SES-5

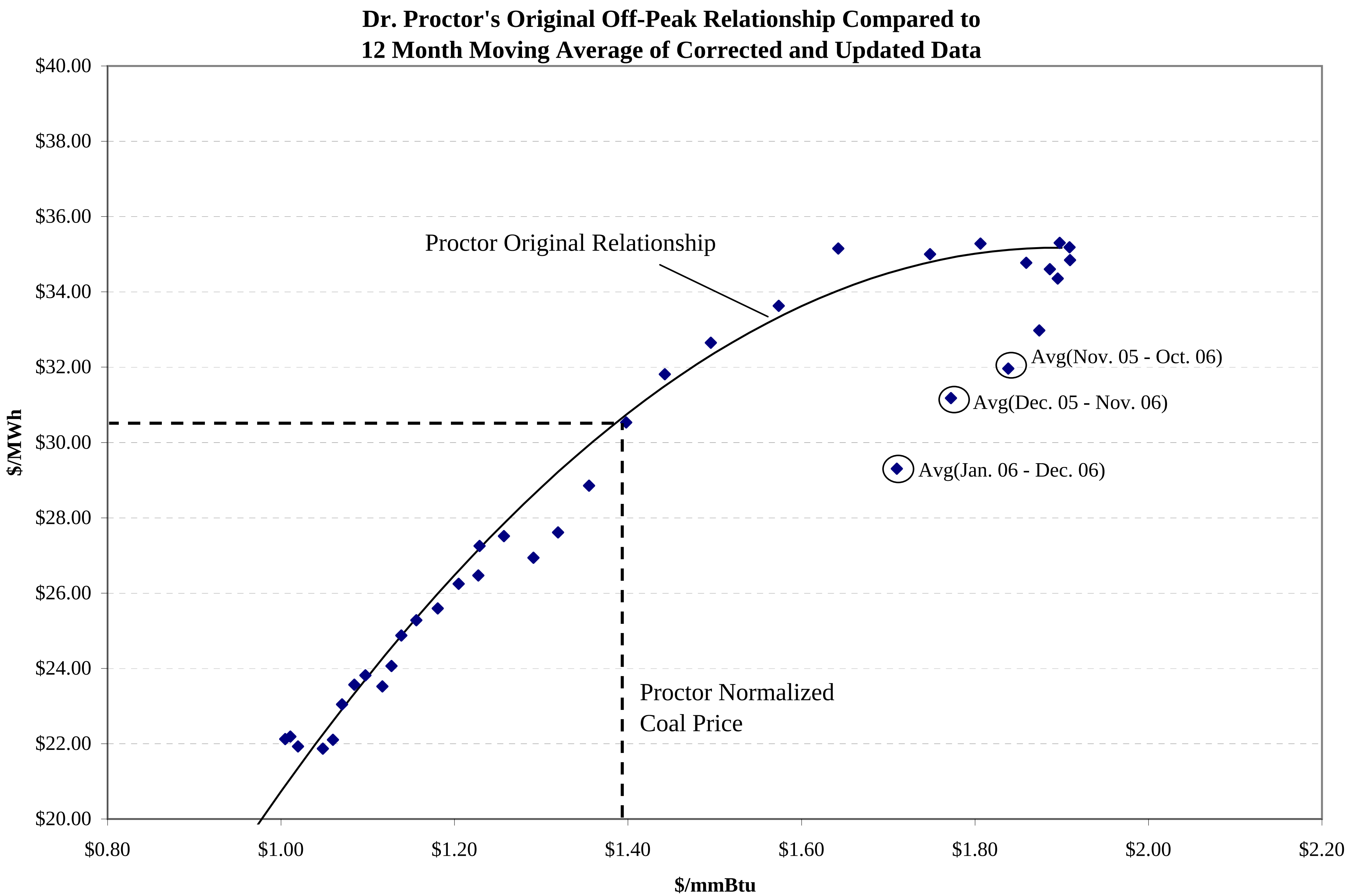


Schedule SES-6

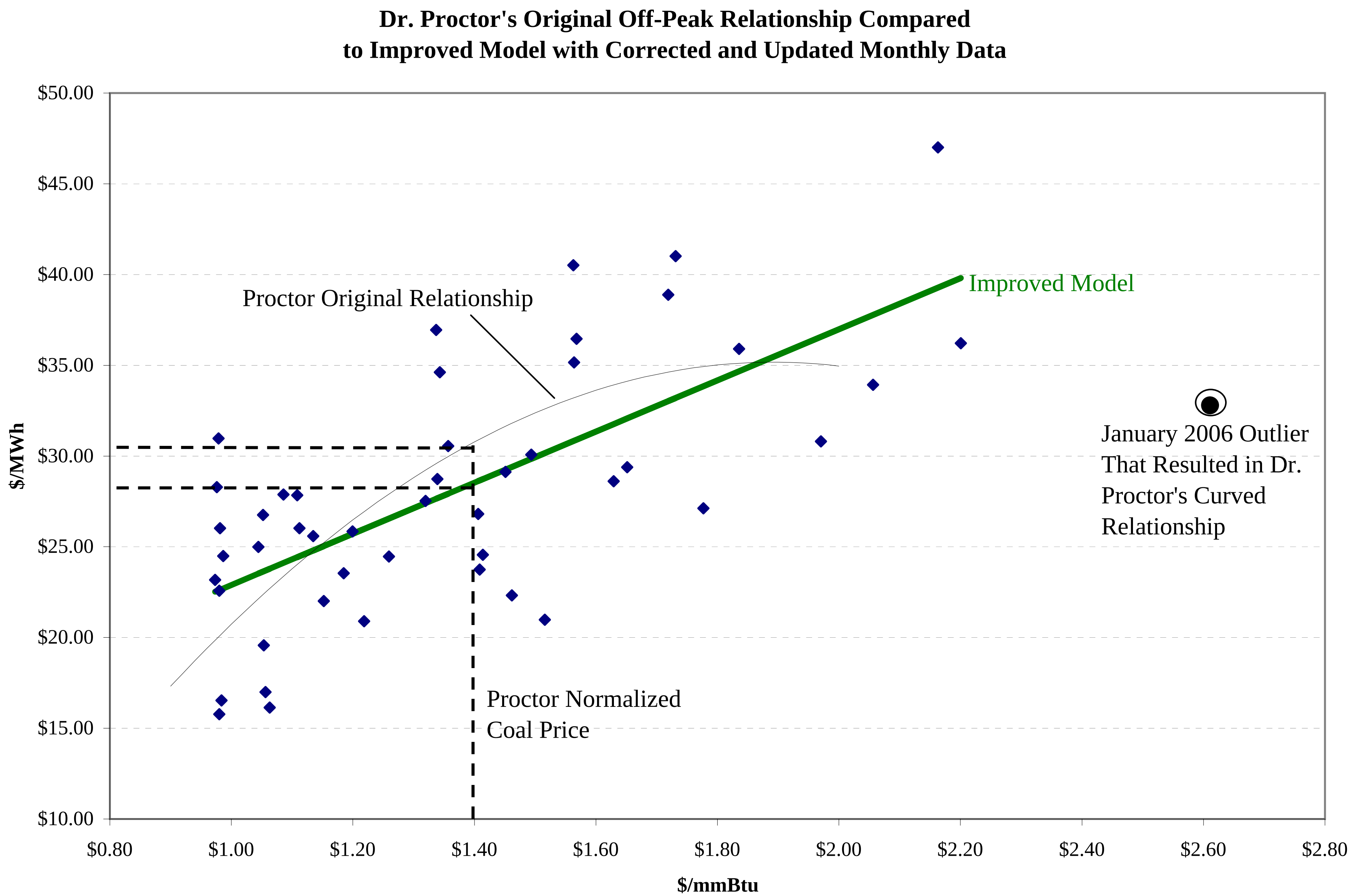
Proctor Gas Price Is Consistent with a Single Day Snapshot from Platts Data



Schedule SES-7

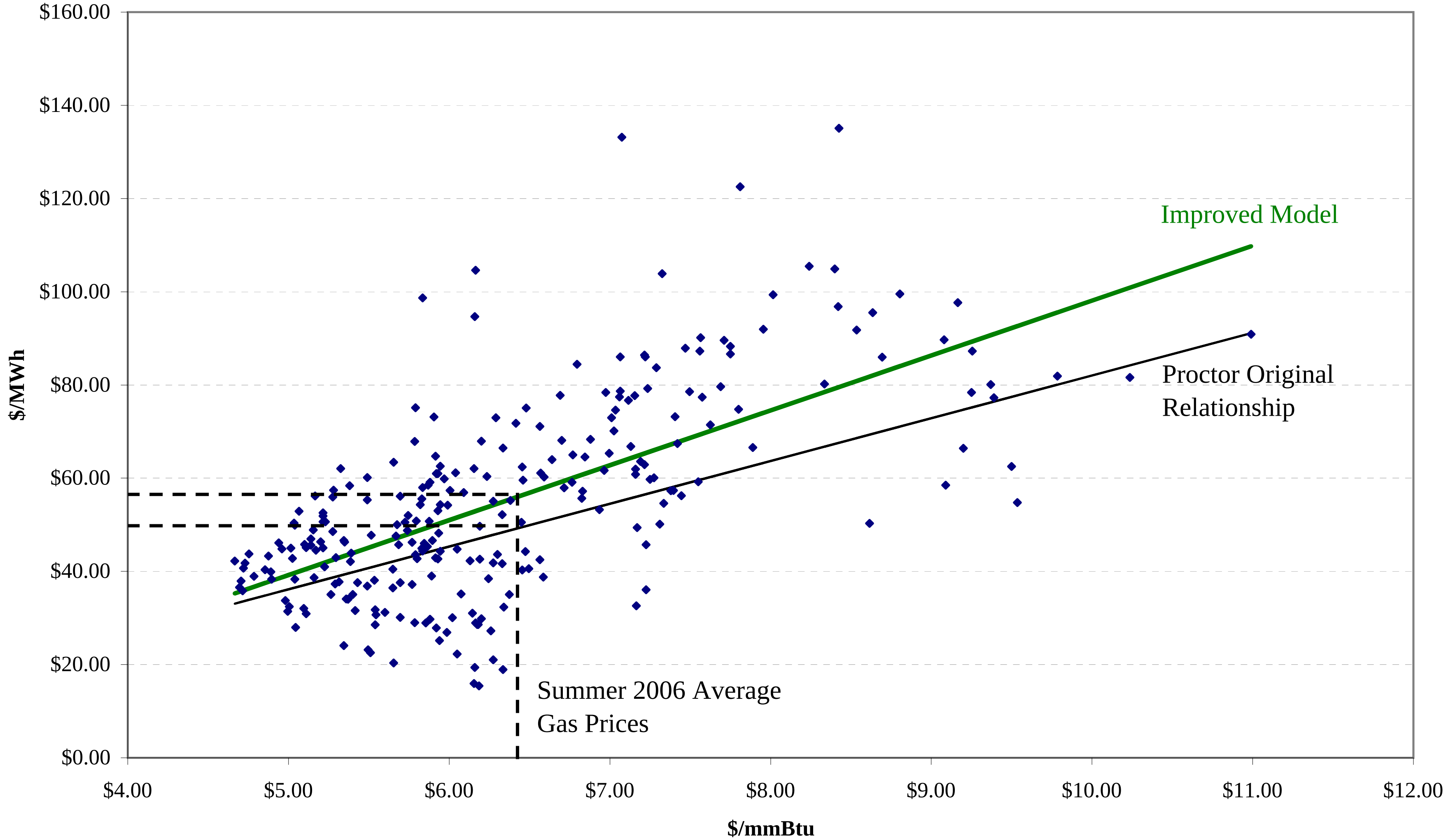


Schedule SES-8-1

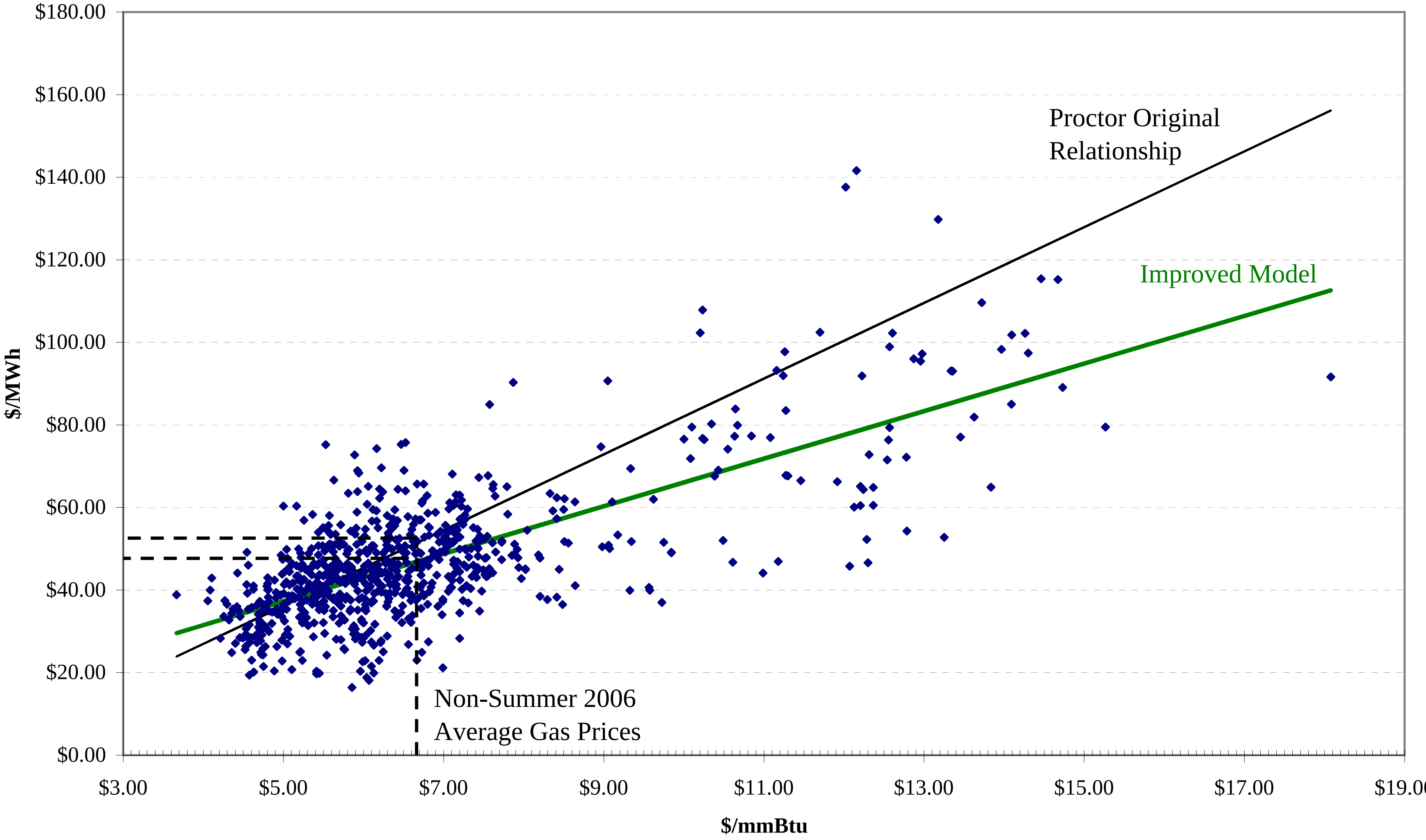


Schedule SES-8-2

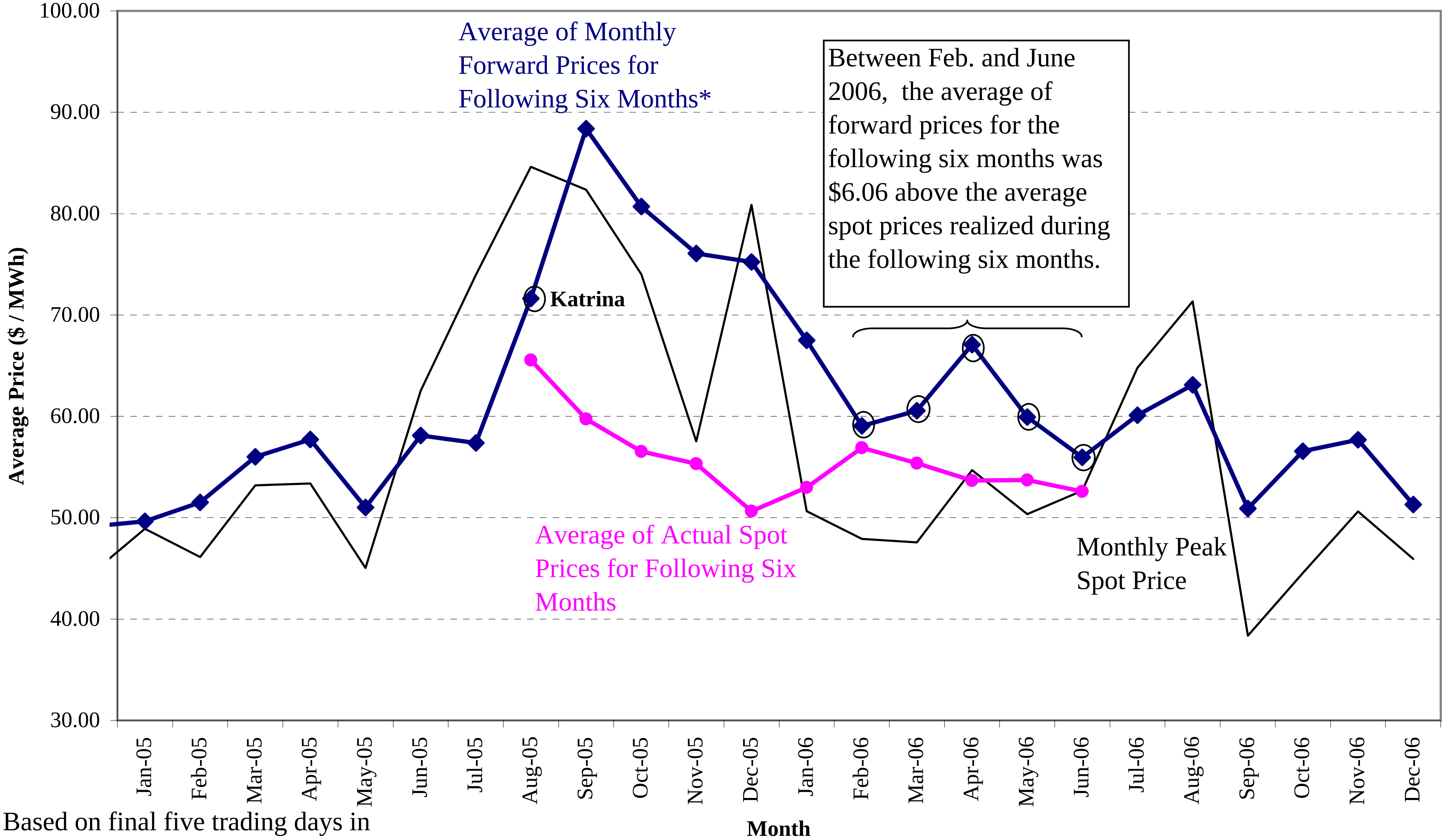
Dr. Proctor's Original On-Peak Relationship Compared to Improved Model with Corrected and Updated Daily Data (Summer Months)



Dr. Proctor's Original On-Peak Relationship Compared to Improved Model with Corrected and Updated Daily Data (Non-Summer Months)

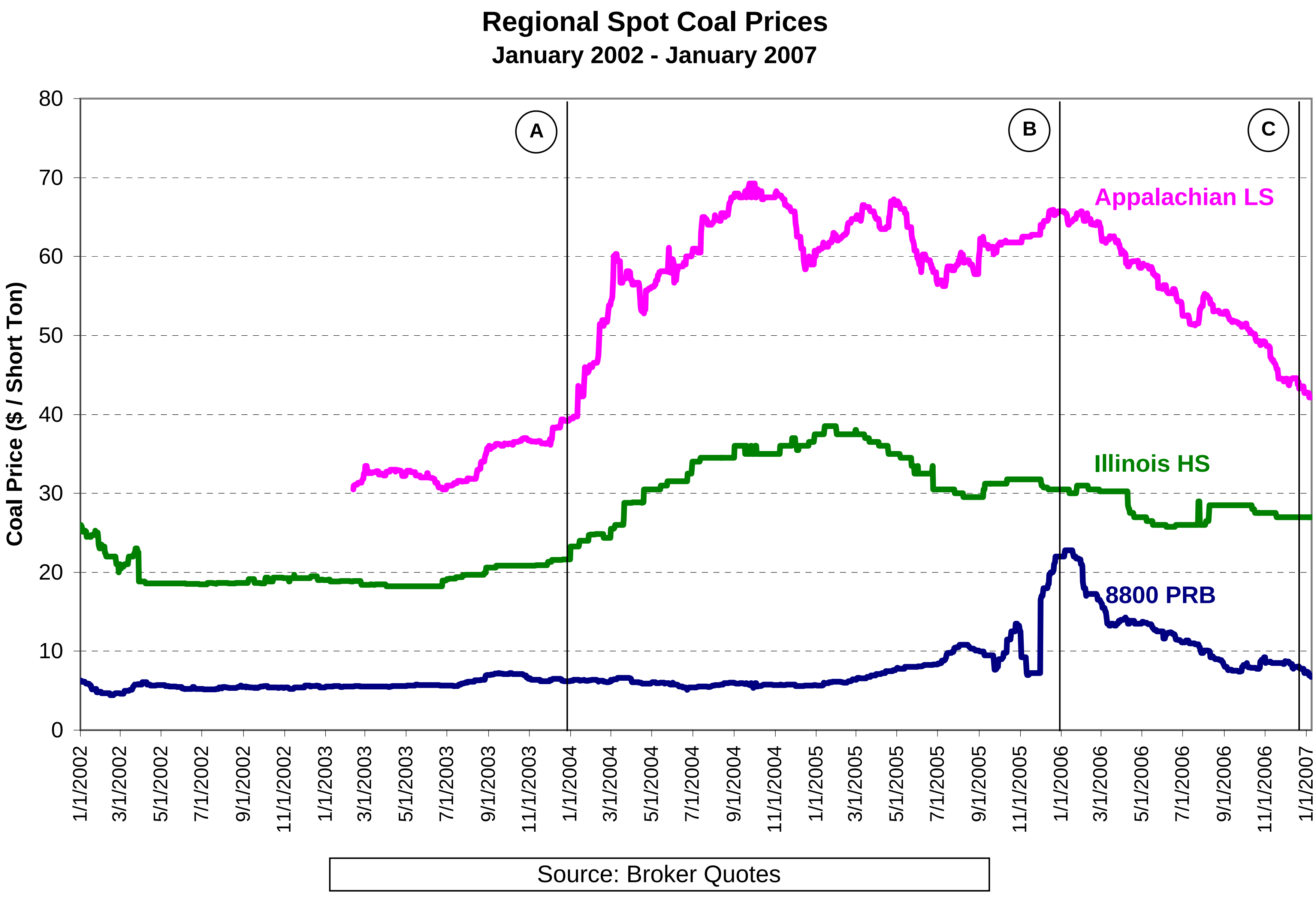


Average Monthly Cinergy On-Peak Spot Prices versus Average Monthly Forward and Realized Spot Prices for Following Six Months



* Based on final five trading days in month where quotes are available.

Schedule SES-10



Schedule SES-11

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2007-0002

AFFIDAVIT OF SHAWN E. SCHUKAR

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Shawn E. Schukar, being first duly sworn on his oath, states:

1. My name is Shawn E. Schukar. I work in St. Louis, Missouri and I am employed by Ameren Energy Inc. as Vice President.

2. Attached hereto and made a part hereof for all purposes is my rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 41 pages and Schedules SES-5 through SES- 11, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Shawn E. Schukar

Shawn E. Schukar

Subscribed and sworn to before me this 29th day of January, 2007.

D. Bradley

Notary Public

My commission expires:

D. Bradley - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #06923315
My Commission Expires 8/6/2010