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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2011-0028

REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
March, 2011

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REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

CASE NO. ER-2011-0028

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven M. Wills. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. Are you the same Steven M. Wills who filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is threefold. First, I will address certain concerns that I have about the weather normalization of test year sales performed by the Missouri Public Service Commission Staff ("Staff"). Second, I will provide comments on Staff's recommendation to change the language of Ameren Missouri's ("Company's") fuel adjustment clause ("FAC") tariff to define the sales used in the calculation of the net base fuel cost ("NBFC") used as an input in the calculation of FAC adjustments applicable to service provided on and after the effective date of the new FAC tariff as "the load at the Company's 'MISO CP node'." Finally, I will provide testimony on the proper allocation factors to use in this case for the wholesale jurisdiction should the Commission decide not to adopt the Company's proposal to treat all wholesale loads as Off-System Sales under the Company's FAC tariff.

Q. What concerns do you have about the Staff's weather normalization of test year sales?

A. First, and most significantly, I disagree with the Staff's decision not to weather normalize the Large Primary Service ("LPS") class. Second, Staff's decision to build its weather normalization models with just one year of data instead of two years of data results in modeling that produces less accurate representations of the actual weather responsiveness of the Company's load.

II. WEATHER NORMALIZATION OF THE LPS CLASS

Q. Did the Staff weather normalize the loads for all classes other than the LPS class?

A. No. Although Staff's Cost of Service Report ("Staff Report") only mentioned the decision not to weather normalize loads for the LPS class, the workpapers submitted with Staff's case show that the industrial portion of the Large General Service ("LGS") class load was not weather normalized either. This class should be included in the discussion with the LPS class.

Q. Why do you disagree with Staff's decision not to weather normalize the LPS and Industrial LGS class loads?

A. The data demonstrates that these classes have a weather sensitive component. Failing to recognize this fact when developing test year billing units potentially results in rates being set based on an abnormal level of sales that does not represent the expected level of sales to be made on a going-forward basis. This is particularly relevant given Staff's decision to update the sales normalization to the twelve month period ending July 2010, which included significantly warmer than normal summer weather.

Q. Do you also disagree with Staff's decision to update the weather normalized sales calculations to the twelve months ending July 2010?

A. No. Updating the weather normalized sales through July is similar to what the Staff and Company agreed to in Case No. ER-2010-0036, and it is reasonable to do it again in this case. But given the conditions in the summer of 2010, it must be recognized that this update moves the test year forward to include a much hotter than normal summer, and exacerbates the problem of failing to include a weather sensitive class in the weather normalization process.

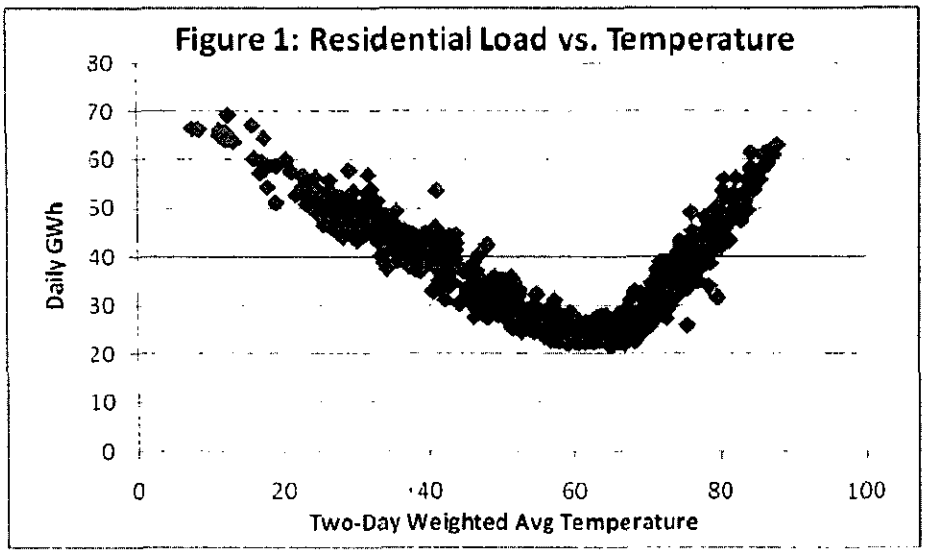
Q. What is the consequence of using sales that have not been weather normalized in setting rates?

A. The sales used to set rates are the denominator of the rate calculation (cents/kilowatt hour). If the denominator is too low, the resulting rate will be too high and under normal conditions with all other things being equal, customers would pay more than the rates were designed to collect. In the opposite situation where the sales included in the denominator of the rate calculation are too high, the resulting rate will be too low and the Company would be expected to under-recover its Commission-approved costs, again assuming all other things are equal.

Q. How do you determine if a customer class' load is weather sensitive?

A. If a statistically significant relationship exists between the daily class load and a daily temperature variable when controlling for other relevant factors such as day of the week and season, the class is by definition weather sensitive. Said another way, if the level of the load is correlated with a weather variable of interest, the load is weather sensitive. It is generally quite easy to indentify weather sensitivity of a load when the daily load data is

plotted in a scatterplot against a temperature variable. Figure 1 below is an example of such a scatterplot for the residential class, which I believe all parties agree is weather sensitive.



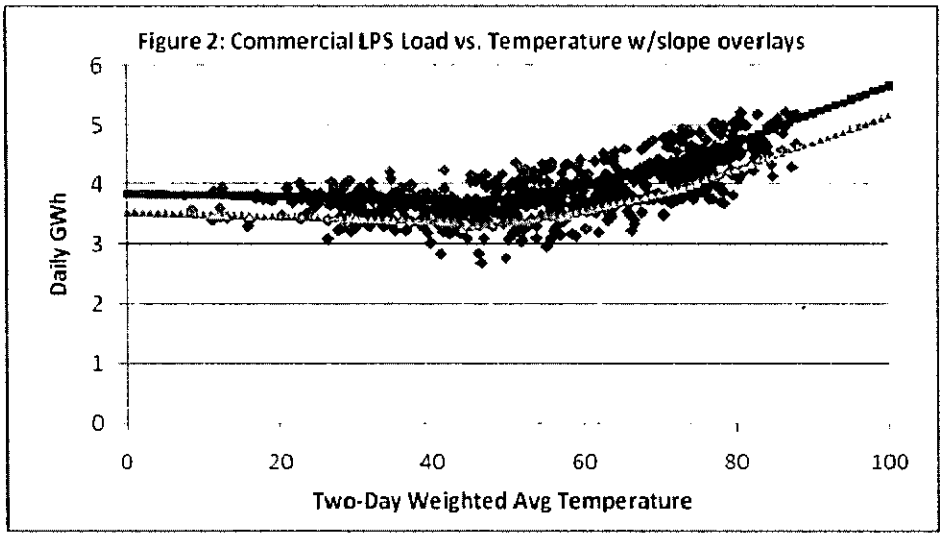
The weather sensitivity is evident in Figure 1 in the upward slope apparent in the plot as you move right from around the 65 degree mark, and also as you move left from around the 60 degree mark.

Q. Do the classes in question meet this standard for weather sensitivity?

A. Yes. For example, in the model that I developed for the Company's direct case for the Commercial LPS class, I used 11 variables to characterize the weather response of the load. The "t-statistics" for these variables ranged from 2.1 to 6.1.[1] This means that all weather variables are statistically significant at the 96% confidence level, 10 of the 11 variables are statistically significant at the 99% confidence level, and the strongest 5 variables are statistically significant beyond the 99.9999% confidence level. This should leave little doubt that this class is weather sensitive. Figure 2 below shows a scatterplot of

[1] A "t-statistic" is calculated by comparing a regression coefficient to its Standard Error. The resulting value can be evaluated using the T-Distribution to determine whether the variable is statistically significantly different from zero, indicating whether the relationship described by the variable can be proven at a given level of confidence.

the Commercial LPS class load against temperature. Overlaid on the plot are two lines that represent the statistical relationship my model established between load and temperature. The top line represents the weekday weather response and the bottom line represents the same for weekends. It is clear visually that there is an upward slope as the data moves right across the graph starting around 50 to 55 degrees.



Q. Beyond the statistical significance of the weather relationship, is there other evidence that this class is weather sensitive?

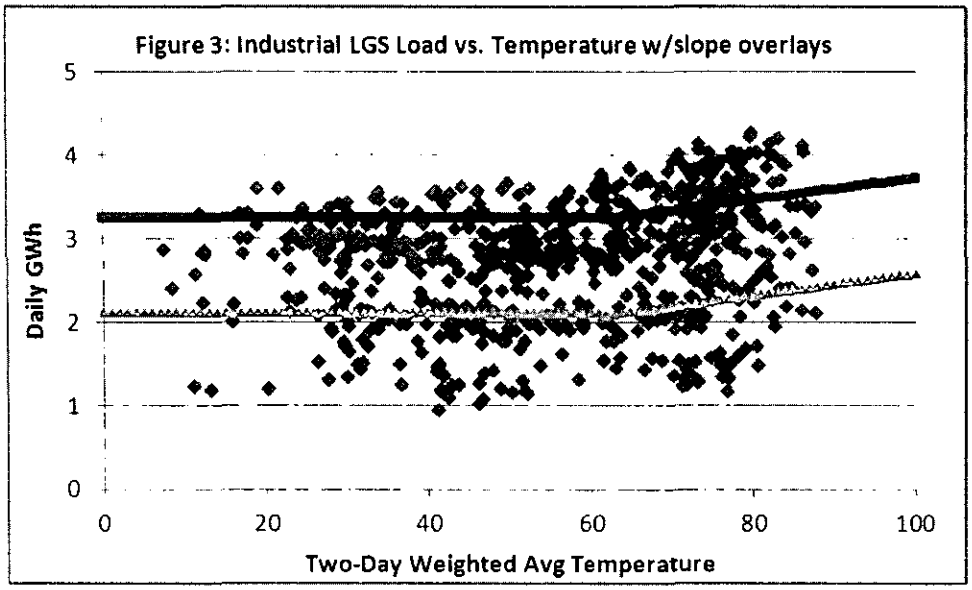
A. Yes. A simple review of the types of customers in this class should lead anyone to conclude that they are likely to have significant air conditioning needs. Those air conditioning needs are obviously driven by weather (temperature), providing additional real world, common-sense evidence that this class is weather sensitive.

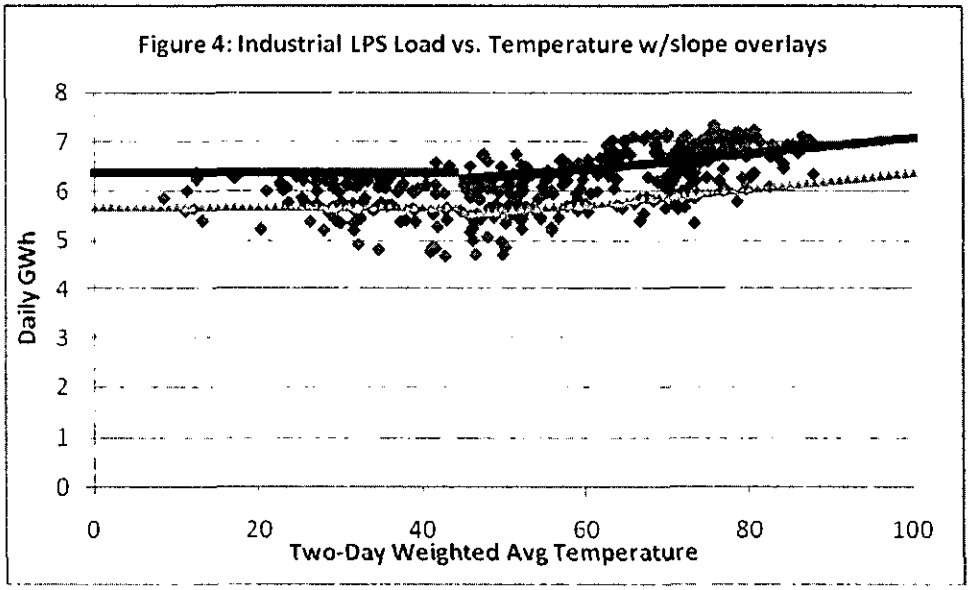
Q. What are the types of customers in the Commercial LPS class?

A. There are universities, hospitals, shopping malls, large office buildings, and a casino. Each of these customers undoubtedly uses significant amounts of electricity to power air conditioning.

Q. What about the Industrial LGS and Industrial LPS classes? These customers are not like the Commercial customers you described above. Why do you contend that these classes are weather sensitive?

A. First and foremost the statistics and scatterplots demonstrate that this is the case. However, despite the fact that many of these customers have significant manufacturing load that is not weather sensitive, many also have office complexes associated with their other operations that do use air conditioning. It is also reasonable to conclude that some of these industrial customers have refrigeration load associated with a part of their processes, which could potentially increase as temperature goes up. As expected, it is true that the weather sensitivity of these classes is considerably less than the residential or commercial classes, but it is also true that weather sensitivity does exist nonetheless. Regardless of what end use is driving the weather sensitivity, the statistics that the weather sensitivity exists are compelling. For the Industrial LGS class, there are two weather variables included in my model; both are statistically significant at the 99.8% confidence level. For the Industrial LPS class, there are four weather variables in the model I built, and they are all statistically significant at the 99.98% confidence level. The scatterplots and model representations for the Industrial LGS and Industrial LPS class can be seen below in Figure 3 and Figure 4, respectively.





It is apparent from the data in Figures 3 and 4 that there is more non-weather variability in this load than the residential or commercial classes, as one would expect with industrial customers. This is apparent in the wider spread of the data vertically across the chart. There is also, however, an undeniable upward slope to the data when moving left to right from temperatures of around 55-60 degrees (daily average temperature) when cooling equipment would kick in for very large operations.

Q. In the Staff's Report in this case, it was argued that "[t]he members of [the LPS] class are not homogeneous and, consequently, a weather response function created for one member should not be applied to any other member. Staff believes it is both appropriate and necessary to annualize rather than normalize LPS for changes in customer usage and count." (Staff Report, Page 59, Lines 1-4) What is your response to this?

A. I have several observations about this statement. First, annualizing the LPS class for changes in customer usage and count and weather normalizing are not mutually exclusive. Taking both of these steps is appropriate for this class. Second, Staff's concern about using a weather response function created for one member of the class being used on another is unfounded. Finally, even if that concern was legitimate, then another approach should be taken to weather normalizing the class, rather than taking Staff's approach, which is to ignore the need to weather normalize the class entirely. Challenges in modeling the load should not cause us to just accept the inclusion of loads that do not represent a normal level of consumption to be used in the calculation of rates. Rather, the best data available should be used to make the best estimate we can.

Q. Please elaborate on your second observation, that Staff's concern about using the weather response function from one member of the class on another is unfounded.

A. The way Staff phrases their concern, it is technically correct. It would be inappropriate to build a model for one specific customer and then apply it to a different customer. However, neither the Company nor the Staff did this, which makes Staff's phraseology misleading. The weather normalization models used by the Company and Staff

are constructed to apply to the *total* class load, not an individual customer load or any subset of the class. A model constructed to describe the weather response of the total class is by definition perfectly applicable to the class itself.

Q. But doesn't the weather adjustment from the class model end up getting applied to the entire class load including the non-weather sensitive customers?

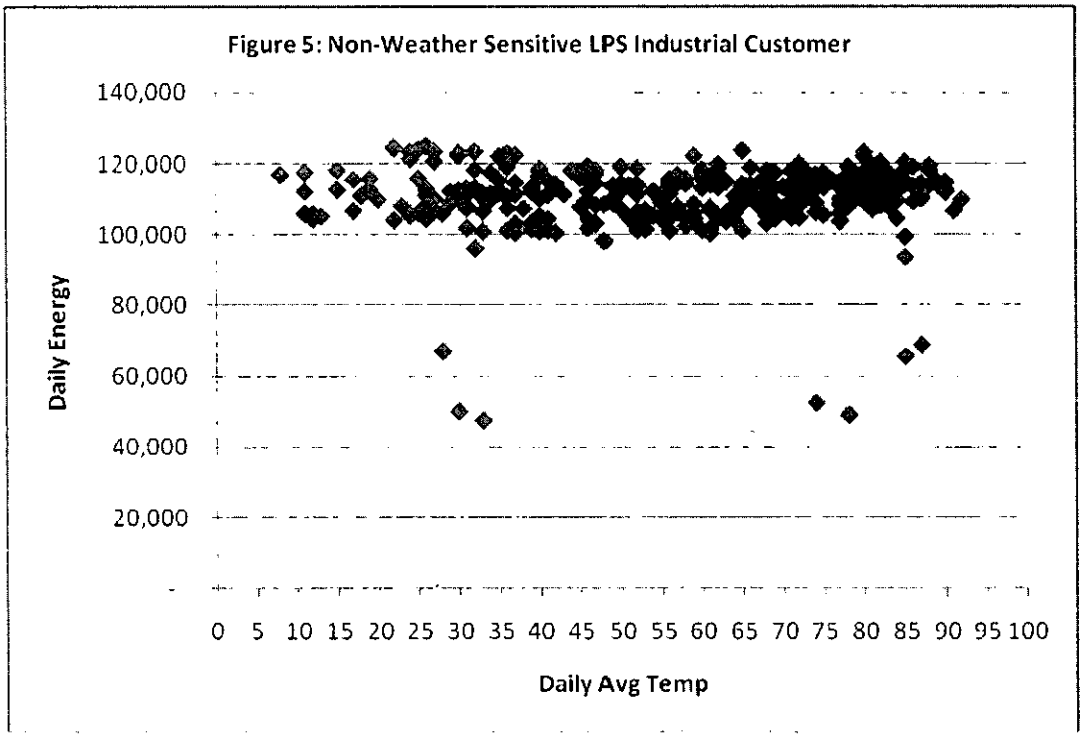
A. It is true that, mechanically, the adjustment is applied to the whole class. But the size of the adjustment is appropriate, given the mix of weather sensitive and non-weather sensitive customers in the class. This is really no different than the treatment of other classes. Not all usage in even the residential class is weather sensitive, but the model based on the total class load accurately captures the weather sensitive component of the load that is appropriate to adjust for differences between actual and normal weather.

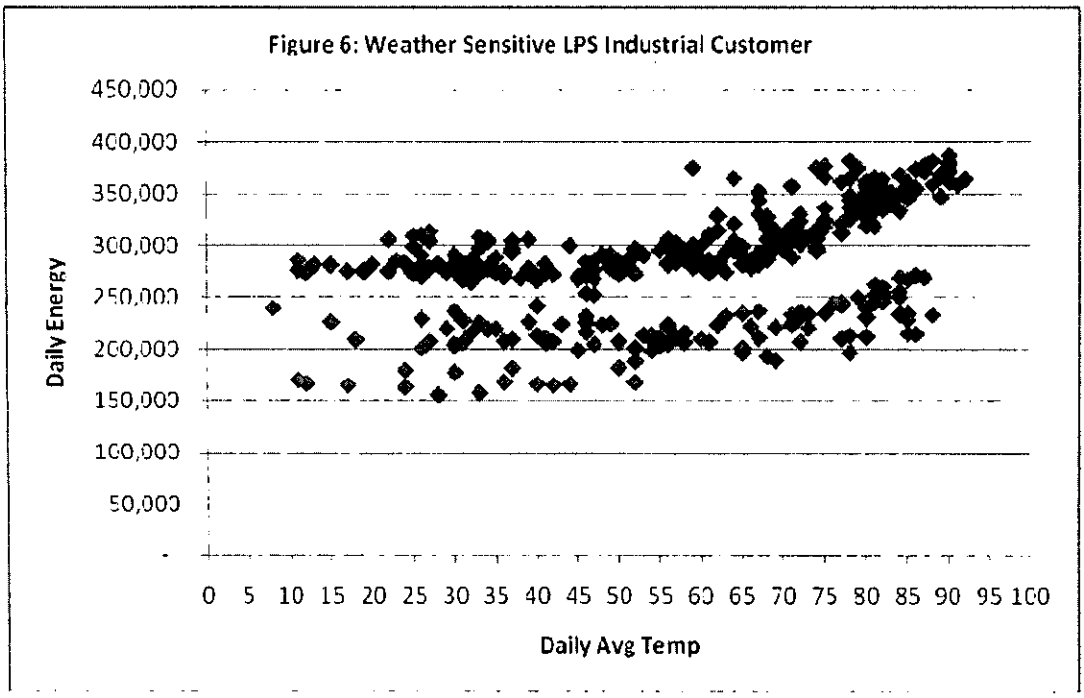
Q. Can you provide an example to demonstrate that the weather adjustment is not overstated when applying it to the entire class including non-weather sensitive customers?

A. Yes. Using 2010 Load Research data for the Industrial LPS class, I conducted an experiment. I made a simple regression model that explained daily class load with daily cooling degree days (Base 55[2]), a seasonal indicator variable and a weekday/weekend indicator variable. This model gives us a base weather response for the entire class. Next, I looked at individual LPS customer loads in order to identify a customer that was weather sensitive and one that was not. Plots of the selected customers' loads are shown against daily

[2] Cooling degree days ("CDD") are a measure of temperature that indicates the need for space cooling equipment. They are calculated by first averaging the high and low temperature for the day. From that result, a base temperature is subtracted. In the case of large industrial customers, cooling starts at a lower temperature than it does for smaller customers, for example residential customers. So in this case, the base temperature of 55 was used. The resulting CDD value is the number of degrees above 55 that the day's average temperature actually was.

average temperature below. Figure 5 is the non-weather sensitive load (note the flat nature of the load with no upward sloping data); Figure 6 is the weather sensitive load (note the upward slope as the data moves right from approximately 55 degrees). The customer represented by Figure 6 is a Company that has a significant office space presence in St. Louis in addition to a manufacturing operation, so the weather sensitivity is likely driven in large part by air conditioning requirements.





For each of these examples, I subtracted the daily customer load from the total LPS load and re-ran the regression. From this, it is possible to see the impact of including a non-weather sensitive customer in a class level weather analysis. The coefficients of the variables in each version of the model are shown in the table below:

	Industrial LPS	*Industrial LPS excluding non-weather sensitive customer*	*Difference in Coefficient*	*Industrial LPS excluding weather sensitive customer*	*Difference in Coefficient*
Intercept	5,069,261	4,961,048	(108,213)	4,871,298	(197,963)
Seasonal Indicator	98,471	96,596	(1,875)	101,996	3,526
Weekday Indicator	442,573	439,907	(2,666)	361,693	(80,881)
CDD 55	31,332	31,348	16	29,033	(2,299)

Q. What conclusions can you draw from this table?

A. The inclusion of the non-weather sensitive customer has a negligible impact on the weather coefficient. Virtually all of this customer's load is represented by the model intercept (meaning the load does not vary significantly in response to the other variables). In

the base Industrial LPS model, the CDD 55 coefficient was 31,332. This means that for every degree the temperature goes up when over 55 degrees, the load is expected to increase by 31,332 kilowatt-hours ("kWh") per day. When the same model is run on the class load less the load of the non-weather sensitive customer, the weather coefficient is 31,348. In this case the coefficient actually went up by a negligible amount relative to the base model coefficient. When looking at the result of the regression where the weather sensitive customer was excluded from the class load, the weather coefficient went down by over 2,000 kWh per day. This means that this customer is contributing significantly to the calculated weather response for the class. In fact, it appears that this customer is responsible for approximately 7% (2,299/31,332) of the class' weather response.

Q. What implications does this have for the weather normalization of the class load?

A. The normalized load on a given day is calculated by taking the difference between the actual and normal temperature for the day and multiplying it by the weather coefficient from the regression model. As an example, imagine a day that was 70 degrees. Normal weather for that day also happens to be 60 degrees. That means on the hypothetical day in question, it was 10 degrees warmer than normal. Our model tells us that the class' load increases 31,332 kWh for every degree it is warmer than 55 degrees. So this day, the class load was 313,320 kWh (10 degrees * 31,332 kWh/degree) higher than would be expected with normal weather conditions. That 313,320 kWh is actually the weather adjustment that would be calculated for that day. If we did the same exercise with the model that excluded the non-weather sensitive customer, we would get essentially the exact same answer for the daily weather adjustment (it would be different by a negligible 160 kWh, a

difference of 0.05%). So the inclusion of this non-weather sensitive customer in the class level model has had essentially zero impact on the class level results of the weather normalization analysis.

Q. Can you please summarize this finding?

A. This has demonstrated why Staff's concern is unfounded with regard to using the weather response function applicable to one customer on another dissimilar customer. In fact, because the weather normalization analysis is performed at the class level, the weather response is exactly appropriate for the class itself. Neither the Company nor the Staff in its normal methodology would take this weather response and use it to normalize an individual customer to whom it did not apply. Including a mix of non-weather sensitive and weather sensitive customers in the same model is in fact a complete non-issue. The non-weather sensitive load, by definition, is not correlated with the weather variable. Therefore that customer's load is represented by the model intercept. When the weather adjustment is made, it only utilizes the coefficient on the weather variable, so the inclusion of such a customer does nothing to increase or decrease the weather adjustment in a remotely material way.

III. HISTORICAL DATA USED TO CONSTRUCT WEATHER MODELS

Q. The second concern you mentioned above regarding the Staff's weather normalization modeling concerned the amount of historical data used to build the weather response models. Can you please explain this issue?

A. Yes. When I built the weather response models used to weather normalize sales for the Company's direct case, I utilized a two-year time period (April 2008 – March 2010) in the analysis. In the Staff's analysis, as evidenced by a review of their workpapers,

the 13-month period ending July 2010 was utilized. It is my contention that the use of more data results in a more robust statistical relationship that better characterizes the weather response of the Company's load. While I have no problem with the decision Staff made to roll forward the period of analysis to include data through July of 2010, it would have been preferable to retain two years of data for the analysis.

Q. Staff indicates in its Report, "[i]n Staff's estimation that part of electricity consumption which is not related to climate control (heating and cooling) was changing perhaps due to the recent changes in economic activity. In an attempt to capture a more likely forward-looking indicator of non-weather electricity usage per customer, Staff determined to use the most recent temperature-load data available at the time and, therefore, based its analysis on the period August 1, 2009 through July 31, 2010." (Staff Report, Page 58, lines 7 through 12). Can you comment on this statement?

A. I agree with Staff's statement that changes in economic activity are impacting the non-weather sensitive portion of the load. That is why I do not have any objection to updating the sales normalization analysis to the twelve months ended July 2010. However, the statistical relationships that are used to make the weather adjustment can still be built with a longer history without sacrificing Staff's desire to capture changes in non-weather sensitive load. Similar to the discussion of the Industrial LPS class normalization experiment I described above, the non-weather sensitive component of the load only influences the model intercept. The key to weather normalization modeling is to make sure that the slopes implied by the weather coefficient in the model are the best representation of the weather responsiveness of load.

Q. Why is it preferable to use more data in developing the weather response?

A. A model built on a larger set of data is simply more robust. There is a wider variety of actual weather conditions experienced over a multiple year period. The weather response function is more complete by having access to a more complete spectrum of weather conditions. Additionally, the model built on two years of data is less susceptible to undue influence from any data that is anomalous or potentially an outlier.

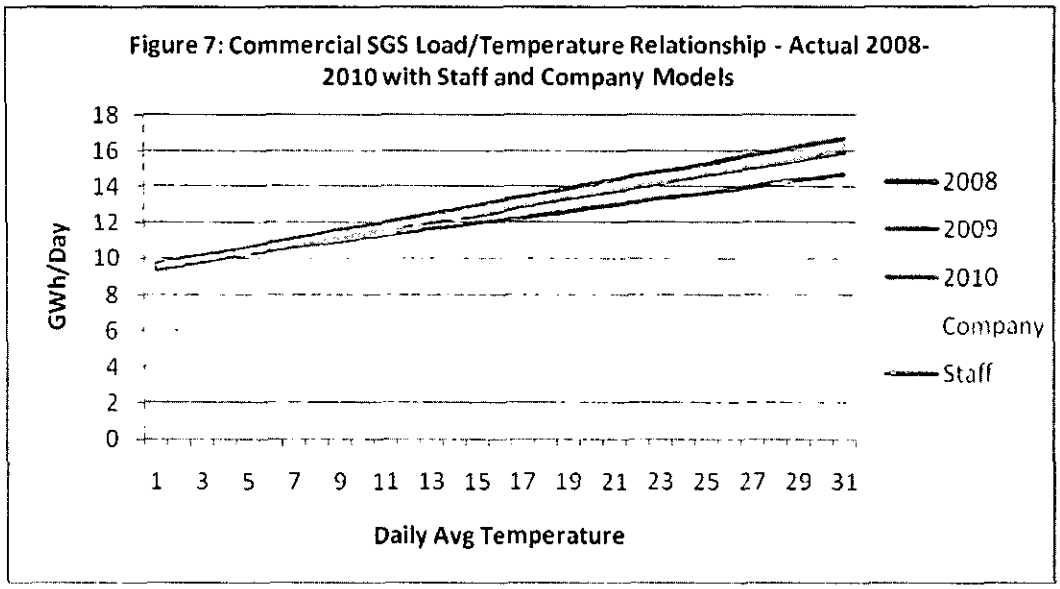
Q. Can you provide any examples where this could have happened?

A. Yes. In looking over the class loads, I noticed that the data for the Commercial SGS class had an unusual pattern in August of 2009. By using only thirteen months of data that included August of 2009, the slope of the weather response function for this class as prepared by the Staff may have slightly understated the actual weather response of the load.

Q. Please elaborate on this point.

A. In late July and much of August of 2009, St. Louis experienced a stretch of unusually mild summer weather. During this time, there were several days with particularly low load in the Commercial SGS class. It is reasonable to suspect that during this stretch, some customers were able to forego air conditioning their facilities entirely. But whatever the reason, during this time the load/temperature relationship appeared to temporarily weaken considerably. I have put together a graph of the load/temperature relationship from July and August of 2009 and compared it to the same months' load/temperature relationships from 2008 and 2010, as well as to the load/temperature relationships implied by the Company and Staff modeling in this case. I calculated the actual weather responses

by using a simple regression between daily temperature and daily load on all weekdays in the time period that had daily average temperatures in excess of 70 degrees. The plot in Figure 7 below shows the linear relationships between load and temperature for July and August for each of these years and for each of the two models (the Company's and Staff's).



Q. What does this graph suggest could be going on?

A. The load/temperature responses associated with each year except for 2009, and from the two models, are clustered fairly tightly, with 2009 well below the rest. The 2009 load/temperature response is clearly the outlier amongst these observations. However, by using the 13 months ended July 2010 in the modeling, undue weight may have been given to the time period that produced this outlier effect. As is apparent in the chart, the Staff's load/temperature response is lower than that calculated by the Company. The lower level of load/temperature response in Staff's model relative to the Company's could unnecessarily reduce the weather adjustment made to sales in the updated test year, particularly the much hotter than normal months of the 2010 summer.

Q. Do you have any additional evidence that the Company's models, using two years of data, more accurately represent the load/temperature relationship of the load than the models that Staff constructed with thirteen months of data?

A. Yes. I applied actual weather readings to both the Company's and Staff's models to simulate loads from an historical time period for two years prior to the test year and compared the results to see which one more accurately represented the actual loads from that time. It is important to do this simulation in a time period that was not used to build the models. This is called "out-of-sample" testing, because the data being simulated was not in the sample used to create the model. This test indicates how well the model generalizes the relationships between the variables, because it is not being evaluated against the time period used to create it.

Q. Which model was more accurate?

A. For every customer class, the Company's model was a more accurate predictor of daily loads for the period studied. For the residential class, the model I built had an average absolute error[3] of 5.06% compared to an average absolute error in Staff's model of 6.05%. The Company model has a full 1% improvement over the Staff model for the residential class. For the other classes, the improvement ranged from 0.32% to over 2%.

Q. Can you please summarize your conclusions on this topic?

A. While the Company supports Staff's decision to update the test year normalized sales calculations to the twelve months ending July 2010, we do not believe the weather response models should be modified to include only thirteen months of data. The

[3] The average absolute error is calculated by comparing each day's simulated load to the same day's actual load. The difference is expressed as a percent of the actual load. The absolute value is taken and then the daily percentages are averaged. This indicates the overall amount of error inherent in the model, regardless of the direction of the model error.

models developed for the Company's direct case should be adopted for performing the weather adjustments to the updated test year sales. These models utilized two years of data and therefore more accurately capture the characteristics of the load/temperature response inherent in the Company's load.

Q. Taken together, what is the difference in the case that results from these two differences in weather normalization?

A. The two issues cause Staff's proposed billing units to be too high. On a normalized basis, the analysis I have done with assistance from our rates group indicates that Staff's normalized revenues are too high by approximately $2.5 million as a result of these issues.

IV. FAC TARIFF CHANGES PROPOSED BY STAFF

Q. In its Report, Staff makes the recommendation that the Company's FAC tariff should be modified such that "the NBFC rate in Ameren Missouri's FAC tariff and the base energy of prospective accumulation periods be calculated using Ameren Missouri's load at its MISO load node. To be consistent, the forecasted recovery period kWh sales also need to be at the MISO load node." Does the Company agree with this recommendation?

A. Subject to a couple of clarifications that are necessary to produce an accurate calculation, yes, the Company agrees that this change is acceptable.

Q. Please describe the clarifications that are required.

A. First, the Company's Midwest Independent Transmission System Operator, Inc. ("MISO") load node described by Staff includes load for certain full requirements

wholesale customers. The tariff change should clearly indicate that only the *retail* portion of the Company's MISO load node should become the basis for these calculations.

Q. Why should the retail and wholesale loads be separated before being used in the calculations?

A. The wholesale customers that are included in the Company's MISO node are currently excluded from the FAC calculations, as provided for by the terms of the FAC tariff. If those customers are not included in the FAC calculations, then their loads must also be excluded from inputs used in the NBFC calculations.

Q. The Company proposed that these customers be included in the FAC rate adjustment calculations. Does that change the need to exclude these customers' loads from the calculation of NBFC?

A. No, it does not. If, as the Company recommends (Ameren Missouri witness Jaime Haro discusses this issue in more detail in his rebuttal testimony), these customers' loads are included in the FAC rate adjustment calculations (i.e., so that they become part of the factor "OSSR" (off-system sales)), it would also be inappropriate to include them in the NBFC calculations or in the load to which the NBFC is applied.

Q. Why would it be inappropriate to include load that is properly classified in factor OSSR in the NBFC calculations?

A. The NBFC is calculated in order to establish a base value against which changes in net fuel costs are compared to calculate the appropriate rate adjustment under the FAC. When establishing the base, the fuel costs incurred in order to make off-system sales are included in the retail customers' revenue responsibility. In return, 100% of off-system sales revenue is used to offset the retail customers' revenue responsibility, which more than

covers the fuel costs made to serve these sales. Therefore, both the revenue and costs associated with off-system sales are fully accounted for and the net costs are the responsibility of retail customers. So these costs must be divided by a load number that is only retail load to match the fact that the full cost responsibility belongs to retail customers. During the reconciliation of an FAC accumulation period, for the same reason, only retail sales are appropriate to multiply by the NBFC to determine the amount of the net fuel costs have been collected from retail customers.

Q. What other clarification is required if the Staff's proposal to use the MISO load node is adopted?

A. In the Staff's Rate Design and Class Cost of Service Report, the Staff indicates that "the expansion factors used to adjust the FPA for losses must be consistent with the loss factor that is used to calculate the NBFC from the test year data. Staff has estimated the expansion factors to be 1.0657, 1.0331, and 1.0000 for secondary, primary and transmission level voltages respectively. These expansion factors have been estimated from Ameren Missouri's most recent loss study and adjusted to be consistent with test year data. These estimates will be revised and finalized during the true-up portion of this case." (Staff Rate Design and Class Cost of Service Report, Page 29, lines 8 through 13) The Company agrees that these adjustments are appropriate under Staff's proposed tariff change. However, the voltage adjustment factors should not be based exclusively on the Company's loss study. Because the Staff is recommending that we use the MISO load node to perform these calculations, it is appropriate to recognize that MISO performs its own loss calculations that are not entirely consistent with the Company's last loss study. The losses determined by

MISO's model should be incorporated in this process and should impact the voltage adjustment factors.

Q. What loss adjustment factors do you recommend for inclusion in the tariff and how did you arrive at them?

A. I recommend loss adjustment factors of 1.0557, 1.0234, and 0.9906 respectively for the secondary, primary, and transmission voltage levels. I arrived at these rates by first utilizing the Company's loss study to account for all transmission and distribution losses applicable to each voltage level's load. Then I reduced the total transmission and distribution losses by the amount of transmission losses that MISO is expected to calculate in their modeling to arrive at the appropriate losses that will remain in the Company's MISO load node. I utilized a two-year average of actual loss rates calculated by MISO to arrive at a 2.2% estimate of losses that are excluded from the Company's MISO load node.

Q. The Staff's rationale for changing the source of load information in these FAC calculations appears to stem from Case No. ER-2010-0274. In that case, it was identified that the kWh sales used to calculate the NBFC applicable to Accumulation Periods 1 through 5 was calculated inconsistently with the way the actual sales in those Accumulation Periods were calculated. However, Staff has suggested this was not the result of an error in Case No. ER-2008-0318. They suggest that "If Ameren Missouri had used its kWh usage at its MISO load node, there would not be the above-described inconsistency." (Staff Report, Page 119, lines 3 through 4). Does the Company agree that this would have solved the problem?

A. Mechanically, yes, had the calculations performed by Ameren Missouri and Staff used the MISO load node kWh it would have solved the problem. However, this option was not available. The FAC tariff, agreed-upon by Staff, the Company and other parties and approved by the Commission, specifically required that sales ***at the generation level*** be used to determine NBFC. Sales at the generation level means an amount of energy that includes associated transmission and distribution losses, which ultimately is the amount of net generation required to serve customers' metered sales. The MISO load node does not measure sales at the generation level, but rather, it measures sales at the transmission level – i.e., it does not include transmission losses. Staff's suggestion that the calculation could have been done differently is false because to do so would have amounted to a failure to follow the specific terms of the FAC tariff. Staff's reluctance to acknowledge that the Case No. ER-2008-0318 calculation was an error is similarly troubling. The tariff calculation requires that sales at the generation level be used. For Staff to make the statement "Staff does not attribute the lack of such result to an improperly calculated NBFC rate" (Staff Report, Page 118, lines 25 through 26) is hard to explain given the fact that the calculation was made with sales that did not include transmission losses, and thus was not determined at the generation level, when the tariff required that the sales that were used be determined at the generation level. In my view, using an input that is different from what the tariff requires is clearly an error. There is really no other way to characterize it.[4]

Q. Must the FAC tariff be changed in order to implement Staff's suggestion that the MISO load node sales be used?

[4] From my perspective, because the tariff required that NBFC be determined using sales at the generation level (Staff agrees that this is so), and where this was not done (and Staff agrees it was not done), then an error in the NBFC calculation occurred, Staff's semantics aside.

A. Yes. Four changes are required, as follows:

- The definition of "Factor S_{AP}" must change, so that it would now be defined as: "Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, as measured by taking the retail component of the Company's load settled at its MISO CP node (AMMO.UE or the successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above."

- The definition of "Factor S_{RP}" must change, so that it will now be defined as: "Applicable Recovery Period estimated kWh representing expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or the successor node), subject to the FPA_{RP} to be billed."

- Factor "NBFC" can be defined using the existing definition, but with one change, that is, the phrase "at the generation level" must be replaced with "based on the retail kWh from the net output calculation in the true-up fuel run."

- The voltage level adjustment factors listed in the tariff must change to: 1.0557, 1.0234, and 0.9906.

The exemplar tariff sheet attached to the rebuttal testimony of Ameren Missouri witness Lynn M. Barnes includes these tariff changes.

V. JURISDICTIONAL ALLOCATION FACTORS

Q. If the wholesale customers' loads are included as off-system sales per the Company's proposal mentioned above, then is it correct that there will be no "jurisdictional allocator" used to allocate the revenue requirement between retail and wholesale customers?

A. Yes, that is correct. This means that all of the Company's costs (and revenues) will be assigned to the retail jurisdiction; in fact, there will be only one jurisdiction for purposes of setting rates. This ensures that all costs associated with load that produces revenues that are taken into account in setting the revenue requirement are also taken into account in setting the revenue requirement.

Q. If these wholesale customers' loads remain excluded from off-system sales, then will a jurisdictional allocator be required?

A. Yes, that is correct. If, contrary to the Company's recommendation, the Commission maintains the exclusion then a jurisdictional allocator is required.

Q. Have you calculated the jurisdictional allocator that should be used in that circumstance?

A. Yes, I have. The fixed allocator should be 99.47% retail and 0.53% wholesale based on the Coincident Peak demands of the respective customer types in the test year. The variable allocator should be 99.44% retail and 0.56% wholesale based on the share of energy served to each customer type in the test year.

Q. Do these allocators represent test year energy and demand ratios of the retail and wholesale loads?

A. Yes, as adjusted for known and measurable changes in the mix of the wholesale customers that will occur prior to the effective date of new rates from this case.

Q. Please describe the reason for the adjustments and how you calculated them.

A. The Company is currently the provider of full requirements energy and capacity for the City of Kirkwood. The contract under which this service is provided expires May 31, 2011, well in advance of the date rates are expected to be effective from this case. Subsequently, the Company will still provide a portion of the energy and capacity requirements of Kirkwood, but substantially less than the full requirement level. I adjusted the test year loads for the City of Kirkwood to match the contract volumes under the new

contract (which is final and has been executed by both parties) based on the specific terms of the new contract.

Additionally, the Company began serving the City of California as a full requirements wholesale customer during the test year. I annualized the impact of that customer addition in the test year loads by incorporating its actual load during the months that it had not been present.

Finally, the Company was serving two partial requirements customers, AEP and Wabash Valley, during a portion of the test year under contracts that are now expired. I removed the loads associated with those customers from the test year.

Q. Should the City of Kirkwood annualization adjustment you calculated be used since the contract change is effective after the true-up date?

A. Yes. The change is known and measurable as of the true-up date. If the allocation factors in the case are not updated to reflect that change, costs will be allocated to a customer that will not be taking service from the Company on day one after the new rates take effect. There will be no revenues available to the Company to cover the allocated costs if the allocation factors are not updated.

Q. Can you provide any evidence that this is consistent with Staff's past treatment of similar situations?

A. Yes, in Case No. EO-2010-0255, the first prudence review under the Company's FAC, there was extensive discussion of the treatment of wholesale customers in rate cases. During cross-examination, and again later during questioning from the bench, Staff witness Lena Mantle gave the following answers:

> For Staff's derivation of the jurisdictional allocators, we asked which - - we check into which municipal customers will be continuing because we

know that there are municipal customers that come off the system and come on to the system. So I'm not certain to any specific municipal utility, but I do know that if there's a municipal utility that will soon be leaving AmerenUE, AmerenUE will not be providing service to it soon after or during the rate case process. We typically do not include that as a municipal customer in our calculation of allocation factors. (Case No. EO-2010-0255, Hearing Transcript Vol. 4, Page 363, lines 3 through 12)

If - - if they file a case and there's only three months of an agreement left, Staff typically does not include that in their cost or in their revenues because it's not going to be there on an ongoing basis. (Case No. EO-2010-0255, Hearing Transcript Vol. 4, Page 388, lines 20 through 23)

Q. Please summarize your testimony on this topic.

A. Consistent with the testimony of Company witness Haro, the Commission should change the FAC tariff definition of OSSR by removing the exclusion for wholesale customers. Should the Commission decide not to take this step, it is necessary to use updated jurisdictional allocation factors with the annualization adjustments I described above in order to match the cost allocation with the expected customer mix that will exist when rates are in effect.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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-2011-0028

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Managing Supervisor of Quantitative Analytics.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Ameren Missouri consisting of 26 pages, 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.

Steven M. Wills

Subscribed and sworn to before me this 25 day of March, 2011.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011