PUBLIC VERSION

****Denotes Confidential Information****

BEFORE THE

KANSAS CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF

MICHAEL VOLKER

ON BEHALF OF

MIDWEST ENERGY, INC.

DIRECT TESTIMONY OF MICHAEL VOLKER

Q: Please state your name, position and business qualifications.

A: My name is Michael Volker. I am the Director of Regulatory and Energy Services for Midwest Energy, Inc. ("Midwest Energy" or the "Company") and am responsible for developing gas and electric tariffs including rates, rules and regulations for utility services, managing the energy services activities, measuring customer satisfaction, and developing forecasts. I hold a Bachelor of Science degree in Mineral Economics from Penn State University and a Master of Economics from North Carolina State University. I began my career in 1984 as an Economic Analyst with the Federal Energy Regulatory Commission ("FERC"). In 1985, I left FERC and accepted a position with Carolina Power & Light Company ("CP&L") in Raleigh, North Carolina as a Junior Rate Analyst. I remained with CP&L until 1998 holding positions in the Rates and Energy Services, Systems Planning, and Marketing Departments. When I left CP&L in 1998, I was the Director of Market Research responsible for developing all qualitative and quantitative market research and for gathering and disseminating competitive intelligence. In 1998, I joined the Boston Consulting Group ("BCG") as an Energy Researcher in the Americas Energy Practice located in Atlanta, Georgia where I was responsible for disseminating Competitive Intelligence and making related recommendations for Energy Practice clients. I joined Midwest Energy in 1999 as the Manager of Pricing and Market Research. I added additional responsibilities managing the energy services activities and obtained my current title in 2006. In 1999 I was also named an Adjunct Professor of Economics and Finance at Fort Hays State University in Hays, Kansas. As an Adjunct Professor at Fort Hays State, I teach Economics courses on a part-time basis. I have testified before this Commission a number of times on rate-related topics.

Q: What is the scope of your testimony in this proceeding?

A: I am sponsoring the following portions of the Company filing: Section 9 Schedules 4-11, Section 12 Schedules 2 to 9, Section 15, Section 17, and portions of Section 18. In Section 9, I am sponsoring all adjustments to Revenue (Adjustment Numbers 1-6) and to the costs of Energy Supply (Adjustment Numbers 7-13) that are passed on to customers via the Energy Cost Adjustment ("ECA"). I provide several Exhibits in my direct testimony in support of the Weather Normalization adjustment to Revenue and Energy Supply. In Section 12 Schedules 2 through 9, I am sponsoring a few miscellaneous allocation factors and all functionalization, classification, and customer class allocation factors used in the cost of service ("COS") study and a map of how they are used. Section 15 details the results of the COS study and proposed or designed rate changes. Section 17 provides comparisons of unadjusted, adjusted and proposed revenues. In Section 18, I am sponsoring the edited (redlined), cancelled, and proposed tariff sheets. Finally, my testimony will address Midwest Energy's plans to expand energy efficiency services and how costs associated with expanded energy services are reflected in other pro forma adjustments.

SECTION 9

Q: What adjustments to the COS are you sponsoring in Section 9?

A: I have sponsored all the adjustments (1-14) to the June 30, 2007 test year revenues and energy supply costs.

The Annualization Adjustment to Revenues and Energy Supply Costs

Q: Please explain the Annualization adjustment in Section 9 Schedule 6.

A: An important principle of ratemaking is the correspondence between costs and revenues for the test year. The test year in this proceeding ends June 30, 2007. The purpose of Annualization is to adjust the test year consumption and corresponding booked revenues to reflect the same 12 month period year as the costs recorded for the test period. Both sales and revenue from rates are based on cycle billed data rather than the test year. Essentially, this means that a considerable amount of the revenue or purchased power costs booked in July of 2007 actually corresponds to consumption that occurred in June of 2007. Likewise, revenue or purchased power costs booked in July of 2006 corresponds to a considerable amount of consumption from June of 2006. Schedule 6 illustrates the calculation of the Annualization adjustments.

The adjustment to revenues is calculated in three steps: First, differences in sales volumes booked in the test year and consumed in the test year are estimated. The amount of volume consumed one month but booked the next is estimated by analysis of billing cycles and the average lag between the meter reading date and the billing date (about five days). Typically, the average bill sent each month is based on usage from the tenth day of the prior month through the ninth day of the current month. Assuming linear usage through a month, this means that on average 2/3 of the usage on bills in the current month are based on consumption from the prior month. In Section 9 Schedule 6, test year volumes are adjusted to remove 2/3 of the volume booked in July of 2006, and add back 2/3 of the volume booked in July of 2007. In this way, all volumes consumed in the test year correspond to all volumes booked in the test year. The net adjustment to sales volumes by class of customer is shown in column 5, of Schedule 6. The second step is to identify the rates to price the change in volume in column 5. The rates are the incremental purchased power costs and the delivery margin rates – columns 6 and 8. The final step is to calculate the total Revenue Annualization adjustment. This is the sum of the change to marginal revenue (column 5 times column 6) and the change to purchased power costs (column 5 times column 8). The Annualization Revenue Adjustment (Number 1) is summarized in column 3 of Section 9, Schedule 4.

Just as revenues need to be adjusted to reflect the actual volumes consumed in the test year ended June 30, 2007, so should the costs of providing the changed volumes be adjusted to reflect the days of the test year. While most costs are not meaningfully different on a booked versus a calendar year basis, the costs of Purchased Power are. Purchased Power costs are booked one full month later than when the consumption associated with the costs occurred. Purchase Power costs booked in July 2007 are for consumption in June of 2007 and belongs in the test year. Purchase Power costs booked in July of 2006 are for consumption in June of 2006 and should not be included in the test year. Therefore, the Annualization Adjustment to Purchased Power costs is simply the difference between Purchased Power costs booked in July of 2007 versus those booked in July of 2006. The Energy Supply Annualization Adjustment (Adjustment Number 7) reflects the adjustment to Purchase Power costs and is summarized on the bottom of Schedule 6.

<u>The Weather Normalization Adjustment to Revenues and Purchased Power Costs</u>

Q: Please explain the weather normalization adjustments in Section 9, Schedule 7.

A: The second adjustment is the Weather Normalization Adjustment. Like the Annualization Adjustment, Weather Normalization is an adjustment to both the revenues received by the Company and to the purchased power costs incurred by the Company.

Q: Why is Midwest Energy proposing the Weather Normalization Adjustments?

A: The purpose of the Weather Normalization Adjustment is to adjust test year revenues and expenses so that the test year accurately reflects the revenues and expenses that would have occurred if the weather had been normal. The revenues and expenses change because the volume of sales changes with the weather. For example, if the test year summer were warmer than normal, there would be more sales of electricity for air conditioning purposes than in a normal year. Both the revenues and the expenses associated with that higher sales volume would need to be adjusted to reflect normal weather. A large portion of revenues are recovered through rates that are based on volumetric charges, therefore revenues vary with the volume of sales. Purchased Power costs vary with the volume of sales as well. However, it is critical to make the weather normalization adjustment to both revenues and costs because a considerable portion of costs associated with utility service are recovered through volumetric rates even though those costs do not vary with the level of consumption. The fact that sales volumes change due to abnormal weather are not reflected equally in changes to revenue and costs make it critically important to adjust for abnormal weather so the test year accurately reflects the expected or normal year relationship between costs and revenues.

A normal year is one in which the actual weather experienced is consistent with the way the weather has been on average for some period of history. In this case, Midwest has averaged weather data based on 30 years of history to develop the estimate of normal temperatures and 10 years of history to develop estimates of normal precipitation. The weather metrics used in the forecast are heating and cooling degree days ("HDD's" and "CDD's") and precipitation. Heating and cooling degree days represent a measure of how temperature impacts the demand for electricity. For precipitation data – which strongly influences sales to irrigation customers – I utilized variance from normal precipitation for the heaviest watering months (May through October).

Q: If the test year is normal, will an adjustment need to be made?

A: No. But typically, no year is normal including this test year, so an adjustment needs to be made to ensure that revenues and costs reflect normal weather. This is particularly important because these rates may be in effect for many years to come. Over time, weather and consumption tend toward normal. If normal weather is not utilized in the calculation of rates then there will be a discrepancy in rates for all years these rates are in place.

Q: Has the Commission approved weather normalization adjustments in the past?

A: Yes. The Commission had approved weather normalizations in a number of rate proceedings both for electric and gas companies.

Q: Please explain how the weather normalization adjustment is done.

A: Weather normalization has four steps:

1) Determine the weather metric and how the metric varies from normal in the test year;

2) Determine the sensitivity of usage to unit variations from normal weather;

3) Apply the sensitivity determined in step 2 to the variation from normal determined in step 1 to determine the variation from normal in test year usage; and,

4) Adjust revenues and costs to reflect the change in usage due to abnormal weather.

Q: What are the weather metrics?

A: The weather metrics are measures of weather that are utilized to determine normal weather and variation from that. In this proceeding, I use HDD's, CDD's and precipitation.

Q: Where does the weather data come from?

A: The source of the weather data is from the Kansas State University Research & Extension service. Both HDD's and CDD's are measured at the Hays Municipal weather station – an Automated Surface Observation Station ("ASOS") of the National Oceanic and Atmospheric Administration ("NOAA"). The precipitation data utilized is from the Great Bend station – likewise an ASOS of NOAA.

Q: Please explain why temperature data was measured at the Hays weather station.

A: Ideally, the best weather station data to use is that which most closely resembles the actual weather experienced by all customers. Midwest Energy's service territory encompasses a very large geographic area that may experience greatly different weather in one location compared to another. Theoretically, matching weather stations within the Midwest Energy service area to sales in the same area would do a better job of explaining heating and cooling related usage variation than just the Hays station. Unfortunately, to use multiple weather stations, one must have some idea of how much consumption is most closely influenced by the weather measured at that station. In other words, usage data needs to be matched geographically to each weather station utilized. Midwest does not have usage information readily available on a geographic basis. The Hays weather data was utilized because it is the location of the highest concentration of customers (residential primarily) whose usage is sensitive to temperature variation. In short, from both an intuitive and statistically measured standpoint, the Hays weather data works very well in measuring usage variation due to temperature. Further, since we are measuring the marginal impact of weather, it seems reasonable to assume that the changes (as measured by the deviations from normal) in the HDD's and CDD's in Hays are likely to be consistent with other parts of the service area even though the absolute measures differ.

Q: Please explain the calculation of the HDD and CDD weather metrics.

A: HDD's are the measure of how cold a day is. They are calculated by subtracting the average of the daily high and low temperatures as measured at the weather station from 65 degrees – the base temperature. The higher the number of HDD's the colder the day and presumably the higher the consumption of electricity for heating or any other purpose sensitive to cold. CDD's are the measure of how hot a day is. They are calculated by subtracting 75 degrees – the base temperature – from the average of the daily high and low temperature.

Q: Why use the base temperature of 75 degrees in the calculation of CDD's?

A: Some energy forecasters use 65 degrees as the base for both HDD and CDD calculation. However, in less humid areas like western Kansas, energy consumption by CDD-influenced uses (like air conditioning) does not begin to increase at as low an average temperature as it would in an area where humidity is higher. Therefore, intuitively it makes more sense to use the higher base temperature. For electricity consumption on the M System, Residential and Commercial customers are sensitive to warm weather as measured by CDD's. On the W System, Residential and Commercial Classes and Irrigation customers are all sensitive to weather as measured by CDD's.

Q: Please explain why the Great Bend weather station was utilized for precipitation data.

A: Precipitation – particularly during certain months of the year – influences electricity consumption for the M System Irrigation classes of customers. Like all other classes of customers, Midwest Energy does not have readily available data on the irrigation class to say geographically where the best weather station location is to determine sensitivity. However, it is known that a significant portion of electric irrigation load served by Midwest is near Great Bend. To a lesser degree, customers near Colby also utilize electricity for irrigation purposes – though not as much as around Great Bend. Intuitively then, it makes sense to utilize Great Bend precipitation data.

Q: Were other weather stations considered for precipitation data?

A: Yes. Hays and Colby precipitation data were also considered. Neither station was effective at helping to explain variation in consumption for the irrigation classes based on the results of the statistical analysis.

Q: How was the precipitation data utilized to explain changes in usage?

A: First, the monthly precipitation for Great Bend was gathered. Then, the normal monthly precipitation was subtracted to determine the average variance from normal precipitation. The data was lagged one month to create a better match between billing cycle sales volumes and calendar month precipitation data. And finally – since precipitation influences electricity usage by the irrigation classes very little in months when watering is not normally done – actual precipitation data was ignored in those months.

Q: Please explain how the usage sensitivity to weather is determined.

A: Regression analysis is used to determine the statistical relationship between the weather variables (the independent variables in the regression equation) and the quantity of electricity demanded (the dependent variable).

Q: Please explain how regression analysis works and how it was used in this proceeding.

A: Regression analysis seeks to explain whether changes in one or more variables (independent variables) can explain variation in another variable (dependent variable). In this case the dependent variable is the monthly consumption of electricity for each class of customer. The independent variables are the weather metrics, HDD's, CDD's and the precipitation variable. The use of regression determines the sensitivity of electricity usage to changes in the weather.

The regression equation is:

$$Usage_t = c + \beta_0(HDD_t) + \beta_1(CDD_t) + \beta_2(Precip_t) + \ldots + \varepsilon$$

Where $Usage_t$ is the monthly consumption of electricity for the class measured in kWh per month. HDD_t, CDD_t and $Precip_t$ are the total monthly HDD's, CDD's, and variance from normal precipitation respectively. The c, β_0, β_1, and β_2 are the regression coefficients. The +... after the Precip variable signifies that there could be other variables utilized to explain usage in the regression equation but for the purposes of weather normalization they are not relevant. The constant term, c, indicates how much electricity would be consumed if the HDD's, CDD's, Precip and any other variable in the regression equation were all zero. The Beta terms, β_0, β_1, and β_2, are the sensitivity terms which measure how much consumption changes if HDD's or CDD's increase by one degree day or if Precip increases by one inch. The ε term at the end of the equation signifies the error in the regression model.

Q: What estimation method was used to determine the Beta coefficients for the weather variables?

A: Ordinary Least Squares ("OLS") – a basic statistical technique - was utilized to estimate the Beta coefficients.

Q: Does OLS do a good job estimating sensitivity to weather?

A: Overall, OLS does a very good job estimating the beta coefficients and determining sensitivity to weather for those classes of customers that are sensitive to temperature or precipitation. It has been utilized for this purpose in countless dockets for gas and electric utilities both in Kansas and across the country.

Q: Which customer classes had test year usage that was sensitive to weather?

A: The Residential classes, Small Commercial and Industrial, Large Power, and Special Contracts classes were influenced by weather as measured in HDD's. The Residential, Commercial, Large Power, and Irrigation (W System) classes were influenced by weather as measured by CDD's. And the Irrigation classes (M System) were influenced by the weather as measured by Precip. It is interesting to note that a meaningful relationship between W System Irrigation and Precip could not be derived. This could be because of a relatively short period of time with which to compare history with the Precip variable, or perhaps because the Great Bend weather station is not an adequate measurement point for the precipitation data. With the inclusion of CDD's in the W System Irrigation model, at least a weather-sensitive model has been derived.

Q: What were the results of the estimations?

A: Estimation results are summarized in Exhibit __(Volker-1).

Q: Please explain what these numbers mean.

A: The numbers in columns 1, 3, and 5 are the sensitivities of class usage to a unit change in the independent (weather) variable. For example, for the M-System Regular Residential class, an additional Heating Degree Day will mean an additional 2,620 kWh of electricity consumption. Likewise, for an additional Cooling Degree Day, usage in the M System Small C&I will increase by 10,226 kWhs. Finally, for one additional inch of rain (between May and October), Irrigation customer electricity usage will decrease by 393,227 kWhs.

Q: What is the T-Stat in columns 2, 4, and 6 of Exhibit__(Volker-1)?

A: The T Statistic is a measure of statistical significance. In other words, are we confident that the actual values of the regression coefficient are significantly different than zero. Or more directly – do the weather variables examined explain variation in the dependent variable (usage)? A rule of thumb is that a regression coefficient is statistically significant if the absolute value of its T Statistic is greater than two. Obviously all the beta coefficients examined have T Statistics with absolute values well over two.

Q: Do your regression models provide a measure of the proportion of the variation in the dependent variable explained by the independent variables?

A: Yes. For each class the R square provides a measure of the proportion of the variation in the dependent variable explained by the independent variables. The Adjusted R-Square values are reported for each class in column 7 of Exhibit___(Volker-1).

Q: What is the total Weather normalization adjustment to sales volumes?

A: Exhibit__(Volker-2) shows how the weather sensitivities were combined with the variance from normal weather to create a class-by-class adjustment to sales volumes. The statistically derived sensitivities are simply multiplied by the test year difference from normal for each of the weather variables to derive the sales volume adjustment for each customer class.

Q: What are the Weather Normalization Adjustments to Revenues and Energy Supply costs?

A: Exhibit__(Volker-3) illustrates the calculation of the Weather Normalization Adjustments to Revenue (Adjustment Number 2) and Weather Normalization Adjustment to Energy Supply Costs (Adjustment Number 8). First, the normalization to Margin Revenue (column 5) is calculated by multiplying the Weather Normalization Volume Adjustment (column 3) times the Average Margin Rate (column 4). The Average Margin Rate represents the unbundled volumetric rates for the non-production components of Midwest Energy's rates for each customer class. Next, the calculation of the Adjustment to Energy Supply Costs (Adjustment Number 8 – column 7) is calculated by multiplying the same volume adjustment (column 2) times the Incremental Power Cost (column 6). The Adjustment to Energy Supply Costs represents two things: the unbundled production component of Midwest Energy's rates for each customer class and the amount of pass through (ECA) revenue associated with the Normalization. Like all other components in the ECA, this amount is an equivalent component in both Energy Supply Costs and Revenues. The total Weather Normalization Revenue Adjustment (column 8) is the sum of the Normalization to Margin Revenue (column 5) plus the Normalization to Energy Supply Costs (column 7).

Annualizing the Oakley Acquisition

Q: What is the next adjustment you are sponsoring?

A: The next adjustment is to adjust revenues and energy supply costs to reflect a full year of the Oakley system being part of the M System.

Q: Why are you making this adjustment?

A: Midwest Energy purchased the City of Oakley municipal electric system effective December 1, 2006. Therefore, revenues and costs associated with operation of the Oakley system are only partially reflected in the test year. This adjustment will ensure that revenues and energy supply costs are not understated in the adjusted test year due to the partial year inclusion of Oakley operations in booked values.

Q: Explain how sales volumes were adjusted to reflect a full year of the Oakley system as part of the M System.

A: Midwest Energy obtained historical monthly sales data from the City of Oakley while analyzing the system prior to the acquisition. Column 3 of Section 9, Schedule 8 is the most recent actual sales volume available by customer class as booked by the City of Oakley for the months of July through November. This is the annualization adjustment to sales volumes.

Q: Explain the calculation of the Oakley Revenue and Energy Supply Adjustments.

A: These Adjustments are calculated in a manner similar to the Weather Normalization Revenue and Energy Supply adjustments. The annualization adjustment made to sales volumes (column 3) is first multiplied by the Average Margin Rate (column 4) to give the dollar Adjustment to Margin Revenue (column 5). Then, the volume adjustment is multiplied by the Incremental Purchased Power cost (column 6) to give the increase in Energy Supply Cost (pass-thru revenue from the ECA) in column (7). This is the adjustment made to Energy Supply Costs reflecting the full year of Oakley as part of the M System (Adjustment Number 9). Finally columns 5 and 7 are summed in column (8) to reflect the combined Margin and Energy Supply (ECA) cost pass-thru revenue. This is the total revenue adjustment to reflect full-year inclusion of the former City of Oakley municipal system customers.

Q: Are you making any other adjustments related to the Oakley acquisition?

A: No. Company witness Tom Meis has addressed any other adjustments to test year rate base or expenses (such as annualizing labor cost) for the Company as a whole rather than specifically for the addition of the former City of Oakley municipal system.

<u>Removing Unregulated Power Sales from Revenue and Energy Supply Costs</u>

Q: What is the next adjustment you are sponsoring?

A: The next adjustment is the Adjustment to Revenues Removing Unregulated Power Sales (Adjustment Number 4) and the corresponding Adjustment to Energy Supply Costs Removing Unregulated Power Sales (Adjustment Number 10). The purpose of these adjustments is to remove the cost and revenues associated with unregulated power sales to wholesale customers for retail cost of service purposes.

Q: Please explain how this adjustment is made.

A: Like the Annualization and the Weather Normalization adjustments, this adjustment is reflected in both revenues and purchased power expenses. The adjustment to revenues is straightforward. On line 1 (column 7) of Section 9, Schedule 9, revenues associated with sales of electricity to wholesale customers are backed out of the test year account 447 (Adjustment Number 4). The corresponding adjustment to Purchased Power expense is done consistent with actual cost of power purchased on behalf of wholesale customers and is equal to the cost of that power that was backed out of the Company's monthly ECA filings during the test year. On row 27 of Section 9, Schedule 9, annual capacity and energy charges backed out of the Company's monthly ECA filings are summarized. Summed in row 27 column 4, these are the total Adjustment to Energy Supply Costs (Adjustment Number 10) associated with removing unregulated power sales to wholesale customers.

<u>Adjustments to Revenue and Energy Supply Costs to Reflect New Purchased Power Contracts (Adjustment Numbers 5, 11, and 14).</u>

Q: What are the next adjustments you are sponsoring?

A: The next adjustments reflect the anticipated costs and corresponding pass-through revenues associated with changes in purchased power agreements and with the purchase of fuel for self generation – particularly for the GMEC.

Q: Why are you making the adjustment for purchased power agreements instead of just using the test year contracts?

A: With the exception of one contract (P Contract), the Company's entire portfolio of purchased power agreements terminates by May 31, of 2008. New agreements are already in place for some of the purchased power requirements, but negotiations are ongoing.

Q: Explain the calculation of Adjustment Number 11 on Section 9, Schedule 10.

A: First, purchased power costs (Account 555) are adjusted. Test year sales volumes are normalized on Section 9, Schedule 11. This Schedule takes into account the test year energy sales and all the pro forma adjustments to sales to yield adjusted sales volumes by class. Next, the normalized sales volume (kWh) and capacity (kW) are allocated to the source – contract or self generation – that will supply it. Normalized sales volume and capacity allocations and their anticipated per unit costs by contract are provided in Confidential Exhibit_(Volker-4). Next, a comparison is made between the test year dollars spent by purchased power contract and the projected dollars from new contracts to meet the energy and capacity requirements. This comparison is made on Section 9, Schedule 5. On column 8 of this Schedule, the difference between booked purchased power and projected purchased power costs is calculated. This difference is Adjustment Number 11, the Adjustment to Purchased Power Costs Associated with New Purchased Power Contracts, and is shown as allocated to each rate class on column 3 of Section 9, Schedule 10.

Q: What about changes in fuel cost for self generation?

A: In addition to purchased power costs, Midwest Energy flows through costs of fuel utilized in Company-owned generation facilities to its ECA mechanism. With the anticipated completion of the GMEC, purchased power will be offset by a considerable amount of generation from the GMEC. The fuel costs associated with a full year's operation of GMEC is Adjustment Number 14 and has been calculated on Exhibit_(Volker-5).

Q: What are the pass-through revenue adjustments?

A: Since both the purchased power adjustment for new contracts (Number 11) and fuel cost (Number 14) flow directly through to consumers via the ECA mechanism, any adjustment made to costs should also be made to revenues. Therefore, Adjustment Number 5, the adjustment to ECA pass-through revenue associated with new purchased power contracts and fuel for the GMEC, is a revenue adjustment that is simply the sum of energy supply cost Adjustment Numbers 11 and 14. These adjustments are summarized on Section 9, Schedule 10 on column 5.

<u>Miscellaneous Revenue Adjustments (Adjustment Number 6)</u>

Q: Please explain Revenue Adjustment Number 6, Miscellaneous.

A: Midwest has two Incidental Service rates, Non-Domestic Annual Service and Incidental Irrigation Service for Irrigation customers. In both cases, meters are only read and billed annually. For billing purposes, annual customer charge revenue for both these rate classes have been booked to only the Non-Domestic Annual Service rate class during the test year. The adjustment is not a change in revenue but rather a shift for that portion of the customer charge revenue that should have been booked to the Incidental Irrigation class. This adjustment is illustrated on lines 2 and 7 of column 6, in Section 9, Schedule 4.

Q: Is there another Miscellaneous adjustment to Revenue?

A: Yes. On line 21, column 6 of the same schedule, revenues are increased to remove the unbilled revenues from the test year.

Q: Is there an Adjustment Number 13?

A: No.

SECTION 12 - ALLOCATION FACTORS

Q: Please briefly describe the cost of service ("COS") model and allocation factors in Section 12 of this application.

A: The Cost of Service Model is a proprietary software model developed for use in this filing. The model fully supports functionally unbundled rate designs and uses available Company cost data to develop the unbundled cost by specific function. By functionally unbundled, I mean the complete separation of costs into functional components. Midwest Energy has defined its functional components as: Production, External Transmission, Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite.

Q: Please define each of those functions.

A: The Production function refers to generation capacity and energy from non-Company resources. External Transmission refers to non-Company owned transmission expenses. Generation refers to Company owned generating facilities, including the new Goodman Energy Center. MWE Transmission refers to the Company owned Transmission system. Primary and Secondary Distribution functions refer to those portions of the Company's Distribution system. Finally, Onsite refers to customer-specific related items such as meters, billing systems, and services.

Q: Please explain how the cost of service model works.

A: The COS model follows the traditional three-step process: functionalization, classification, and allocation. First, all inputs (rate base, expenses, and revenues) are divided into the functional components noted above. Unlike traditional models, the COS model does not depend solely on FERC account codes to functionalize inputs. Instead, the model functionalizes the appropriate account items through the use of allocation factors derived from more detailed information. Once functionalized, items are classified into demand, energy, or customer components. Finally, the classified components are then allocated to customer rate classes based on the cost causing characteristics of each customer class.

Q: What are the advantages of a functionally unbundled cost of service model?

A: For Midwest Energy, this allows for a better separation into the basic components of rates – Energy Supply, Local Generation, Transmission, and Distribution. The Energy Supply component is the cost of securing power for retail customers. Energy Supply is either purchased power costs or the cost of fuel to run Company-owned generation that are passed through directly to customers. This means that on a monthly basis an adjustment is made to rates via the ECA filings for changes in the cost of Energy Supply. The ECA ensures complete recovery (or pass through) of prudently incurred Energy Supply costs by having a true-up mechanism for over or under recovery of these costs. Unlike Energy Supply costs, the other unbundled portions of rates are only adjusted up or down during a general or base rate case such as this proceeding. Midwest Energy last implemented a change to base rates with a small rate increase in February of 2003 (less than 1 percent) which followed a small decrease in July 2000 after the original unbundling of base rates in Docket 99-MDWE-272-RTS. For practical purposes, base rates are at the same level they were in 1989 for the M System. W System base rates have not changed since Midwest Energy acquired the system in 2003. Since the nature of costs compared to the way they are recovered through rates is very different, it is very important to unbundle rates carefully.

Functionalization Allocation Factors

Q: How are components of the COS allocated to each function?

A: Functionalization is the process of assigning portions of rate base, revenues and expenses to the seven functional components; Production, External Transmission, Local Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite. Approximately 40 allocation factors have been derived either exogenous to the COS model or within the model itself. The functional allocators are listed in Section 12 Schedule 6 with the percent of the allocation to each of the seven functions.

Q: How are the functionalized components classified?

A: Classification is the process of further breaking down functionalized components into demand, energy, or customer classifications. Approximately 70 classification allocators have been derived either exogenous to the COS model or within it. The classification allocators are listed in Section 12, Schedule 7 with a brief description and the percent allocation to each of the three classifications.

Q: After rate base, expense, and revenue data have been functionalized and classified, how are they allocated to customer classes?

A: Class allocation is the process of allocating classified components to rate classes. Approximately 350 customer class allocators have been derived either exogenous to the COS model or within it. The classification allocators are listed in Section 12, Schedule 8.

In addition, in Section 12, Schedule 9, is a map that summarizes the complete functionalization, classification, and class allocation factors line by line through the COS study. The map is organized with the amount to be allocated, and the functional allocator on each page. For each function, the classification allocators are listed. And finally, for each classification in each function, the customer class allocators are listed.

<u>SETION 15 - COST OF SERVICE</u>

Q: Please summarize the results of the COS study.

A: The third and final phase of the COS model – the class allocation phase – is summarized in Section 15, Schedule 1. This schedule shows for each rate class, the line by line results of the pro forma COS study including detailed rate base items, expenses, revenues, net income, and rate of return (ROR) at current rates.

Q: Please explain Schedules 2 and 3 of Section 15.

A: Schedule 2 of Section 15 summarizes the results of the functional unbundling in this model. In this Schedule is shown the rate base, expenses and revenue requirement by each of the seven functions: Production, External Transmission, Local Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite. Schedule 3 of Section 15 provides the Unit Costs by unbundled revenue function for each rate class. Schedule 3 is particularly useful when different regulatory mechanisms are used to adjust the rates in each function. For example, the unit costs of Production and External Generation are reflected in the embedded power costs in rates and are recovered via the ECA mechanism. Since the Company has proposed a Formula Transmission Rate and Rider, the unit costs for the unbundled transmission function are consistent with the template used to derive the transmission revenue requirement for the formula rate.

The overall revenue requirement by customer class is summarized on line 30 of Section 15, Schedule 2.

Designed Rates and Revenues

Q: Are these the Rate Class Revenue Requirements the Company is proposing for each rate class?

A: No they are not. The COS study with equalized RORs is a starting point on how the Company should meet its total revenue requirements, but there are a number of reasons to vary the ROR for each rate class. These include:

1) Different risks associated with serving different classes of customers;
2) Competitive issues;
3) Mitigating rate change impacts;
4) Administrative simplicity; and
5) Social policy.

These issues have been taken into account when designing proposed rates.

Q: Please discuss Midwest Energy's rate design objectives.

A: Midwest Energy has designed rates to meet a number of objectives:

1) The designs must provide enough revenue to allow the company to meet the Company's revenue requirement as derived in the COS model;
2) The designs should move toward the class COS results;
    a. Fixed charges should ultimately be at least 75 percent of the COS fixed charge, however as an intermediate step in this proceeding we used a 60 percent target.
    b. Class ROR should be closer to the System ROR than previous rates.
    c. Avoid negative class RORs.
    d. Practice gradualism when moving rates toward COS results.
3) The designs should simplify administration by combining rates classes where practical; and,

4) Impacts on classes should be minimized where possible.

Q: Do the recommended rate designs meet all of the Company's objectives?

A: No. Achievement of one objective can compromise the achievement of others. For example, it may be impossible to achieve a positive rate of return and not severely impact a rate class due to the magnitude of the increase required.

Q: Do the recommended rate designs provide enough revenue to meet the System revenue requirement?

A: Yes. Section 15, Schedule 4, provides the proposed unbundled rates for the M and W System retail customers. Proposed rates in Section 15, Schedule 4 yield revenues within one thousand dollars of matching the COS based revenue requirement. The total proposed revenue is shown in column 1 on line 47 of Schedule 4. Comparing this with line 326 from Schedule 1 (the COS summary output) shows that the proposed rates yield revenues that very close to the COS revenue requirement.

Q: Please discuss how the rate designs bring rates closer to the second rate design objective – moving closer to the COS results.

A: Rates are brought closer to the COS in three ways: First, rates are designed with customer charges that have been increased for a number of classes – especially those that do not have a demand component to their rates. This results in a higher portion of fixed costs to be covered by fixed charges and moves rates directionally toward the COS results. Second, RORs are increasing for each class that are below the System required ROR. Finally, with only a few exceptions, the rate designs yield a positive ROR for all classes. The proposed M System Incidental Irrigation rate, the W System

Residential Demand Rate, and the W System Irrigation rates yield negative RORs despite increases that are well above the system average percent increase. I believe that further increasing the proposed rates would be overly burdensome to these rate classes.

The proposed RORs for each class of customer are shown on line 51of Section 15, Schedule 2. The current RORs by class are shown on line 305 of Section 15, Schedule 1. Under current rates, thirteen rate classes are yielding negative RORs. While the RORs under proposed rates are moving in the right direction with no need for additional explanation, the objective to recover a higher percentage of fixed costs through fixed charges does. Even under proposed rates, the Company is not close to meeting its desire to cover at least 75 percent of its fixed costs through fixed charges. The proposed rates are merely a step in the right direction. A large portion of utility service expenses are not sensitive to changes in volume, but rather are fixed in nature. Yet by far the majority of utility service revenue is based on volume. From a utility standpoint, this leaves an excessive portion of the revenue subject to seasonal usage and weather. From a customer perspective – particularly a residential customer – it makes bills in high consumption months even higher than they should be. From an economic standpoint, this leads to inefficient consumption decisions because of poor price signals. It is becoming more important to send the appropriate price signal as new technologies such as Distributed Generation (DG) that may enhance or even replace the distribution system become viable. The economic decision by a customer or the utility to install DG will look at the incremental costs and benefits. To include recovery of fixed costs on the basis of volume will likely inflate the incremental benefit of the investment in DG by the customer. A poor economic decision may result.

Section 15, Schedule 3, provides the unit cost of service based on the COS study results. Note that on line 46 of this schedule, the total Customer classified costs in dollars per meter per month are well below the proposed customer charges for most classes of customers. Again, the proposed rates go in the right direction since customer charge revenue would increase by a greater percentage than the overall revenue requirement.

Q: Please explain why there are no proposed rate changes under Section 15, Schedule 4 for either the Lighting or Special Contract Classes.

A: The Special Contracts rate class has rates that are fixed by contract, subject to Commission approval, and therefore Midwest is not proposing any rate changes to this class. Since each contract is different, it is not possible to show the unbundled components as a class. However, assuming a normal year, the total revenue from the class will be the same as the test year. Since the ROR achieved by this class is slightly greater than the requested ROR for the system (see line 51 of Section 15, Schedule 4), requested revenues from other classes have been reduced. Small Customers are not subsidizing special contract Customers.

Similarly, for the Lighting Class, Midwest Energy is not proposing any changes to existing rates. Lighting service is more of an end use product that most customers have deliberately chosen to buy on a bundled basis. Functionally, this COS study does not unbundle end uses. This does not mean that overall costs have not been allocated appropriately to this class but rather changes to the rates required to recover the costs requires a different type of analysis than has been conducted here. Again, the ROR for Lighting is well above the requested overall system ROR – thereby reducing required revenues from other classes. However, costs have changed between lighting system components in recent years. Further, environmental issues have made the availability of some types of lighting problematic. These issues need to be addressed – but not in the context of a general rate proceeding since the Lighting class is exceeding its overall revenue requirement. The Company must conduct a more detailed study of this class before making any recommendations for changes to rates. At this time, the Company will evaluate the current lighting offerings, update pricing of existing offerings to be more reflective of current costs, update offerings to reflect new technologies, cancel offerings that are no longer viable due to environmental concerns or technological obsolescence, and assess the overall impacts on revenues. If the study suggests a need to change the rates, Midwest Energy will make a recommendation at that time.

Q: Have you proposed any new rates for the M System?

A: Yes. I have split the General Service Large ("GSL") rate class into two rate classes. Currently, the GSL rate schedule includes any General Service customers with a peak demand in the billing month of July, August or September of greater than 30 kW up to as much as several megawatts. It has become apparent that there are considerable differences in cost causation characteristics between customers so dramatically different in size. As a way to more equitably recover costs as caused by different customers, Midwest Energy proposes to create a new intermediate class of customers on its M System, General Service Medium ("GSM").

Q: Please describe the GSM rate class.

A: The GSM rate class will be comprised of customers with a summer peak demand between 30kW and 200kW. This class will apply to most customers formerly under the GSL rate schedule. Approximately 600 of the 670 customers currently under the GSL schedule will migrate to GSM. The GSL rate schedule will now apply to General Service customers with a peak summer demand of greater than 200kW – approximately 70 customers.

Q: Will customers migrating to the new GSM rate class be subject to a high rate increase?

A: No. Although the proposed increase in revenue for the GSM class is higher than for the GSL class, the proposed GSM rate increase is still less than the average for all M System customers.

Q: Why did you set the division between GSM and GSL at 200 kW (summer peak)?

A: The 200 kW summer peak seems to be a somewhat natural division between medium and large customers. To illustrate: of the almost 600 customers that would migrate to the GSM rate class, less than 20 had a summer peak greater than 150kW and 500 had a peak less than 100kW. Further, this division is also consistent with the Large Power rate under existing rates on the W System. Therefore, from an administrative standpoint, the 200kW break point from Medium to Large General Service is attractive.

Q: Are you proposing Time of Day or Electric Space Heating rate options for the GSM class as currently exist for the GSL class?

A: No. There are so few customers on those rates (approximately 41 total) that it doesn't make much sense administratively to design separate optional rates. However, for customers electing to utilize these optional rates, there will not be a 200 kW division between small and large. The same optional rates will apply to General Service customers with a summer peak greater than 30kW even if they have a summer peak greater than 200kW.

Q: Will some customers on General Service Small move up to the new General Service Medium Rate?

A: Possibly. I have clarified the size of customer that may be considered a General Service Small ("GSS") customer. Customers may not have a demand greater than 100 kW in non-summer months and remain in the GSS class. Similarly, the maximum demand allowed in the GSM class is 300 kW even in the non-summer months. In this way, the general service classes have been better defined based on customer peak demand characteristics.

Q: Have you proposed any new rates on the W System?

A: Yes. Almost 20 percent of the customers currently on the W System General Service schedule are either oil field or irrigation customers – classes with usage characteristics that are different than the typical General Service customer. I am proposing new customer rate classes designed to more accurately recover costs attributable to these customer classes.

Q: Please discuss the proposed W System Irrigation rate.

A: The proposed W System Irrigation schedule is designed to more accurately reflect how the irrigation class causes costs to the Company. Irrigation customers as a class use dramatically more energy in summer months than in non-summer months. The new rate design has a higher demand charge than that of the General Service class and consistent with the high demand in the summer months. Also, the irrigation class requires causes higher fixed costs per customer than General Service customers. The proposed W System Irrigation rate has higher monthly customer charges than the General Service class to reflect the higher fixed investment required of that class.

Q: Will irrigation customers face a higher increase on this rate than on the General Service rate?

A: The General Service customers will face a larger percent increase on average than customers in the new Irrigation class. However, the new Irrigation rate will result in higher rates for the irrigation customers than they would have faced if they had stayed as General Service customers. This seems appropriate since the irrigation class usage characteristics are so heavily weighted toward high-cost periods.

Q: Please discuss the proposed W System Oil Field rate.

A: Like the Irrigation rate, the W System Oil Field rate is designed to better reflect how the oil field class causes cost to the Company. Higher fixed investment per customer for the oil field customer is reflected in the higher customer charges of the proposed rate compared to the General Service rate. Similarly, high load factors of the oil field customers are reflected with lower energy charges in the proposed rate compared to the General Service rate.

SECTION 17

Q: Please explain the schedules in Section 17.

A: Section 17, Schedule 1 examines kWh sales volume and revenues as booked in the test year, as adjusted, and as proposed for all rate classes. Revenue is separated into base rate revenue and revenue attributable to the Energy Cost Adjustment. Schedule 2 presents adjusted and proposed revenues, average customers, per unit costs, and nominal and percent increases by customer class.

SECTION 18

Q: Please discuss the tariff changes you are sponsoring in Section 18.

A: I am sponsoring the changes to the Master Tariff that are reflective of the proposed rate design for M System rates in Section 15, Schedule 4. As previously mentioned, I am sponsoring the new General Service Medium (GSM) tariff, and changes to the General Service Large (GSL), GSL Time of Day, and General Service Heating tariffs. I am sponsoring all the changes to the W System tariff sheets including the new Oil Field and Irrigation classes. I am sponsoring the new Transmission Service Charge Adjustment Rider sheets as described later in my testimony and by Company witness Overcast. I am sponsoring changes to rebase both M and W Systems in the Energy

Cost Adjustment tariff. Finally, I am sponsoring all changes to the Table of Contents tariff to reflect the previous changes.

Q: Please discuss the Transmission Service Charge Adjustment Rider

A: Pursuant to K.S.A. 2007 Supp. 66-1237(b)(2), the Company is seeking approval of an initial Transmission Delivery Charge ("TDC") and a mechanism to adjust this charge through a formula. The Company refers to this TDC as its Transmission Service Charge ("TSC") – which is the Company's unbundled retail transmission rate by customer class. Company witness Overcast has sponsored the Formula Rate Template utilized to calculate the Annual Transmission Revenue Requirement ("ATRR"). The Template updating the ATTR is attached as Annex 1 to the tariff and the Protocols to be followed in filing the Template are attached as Annex 2 to the tariff.

Q: Please explain what the TSCA tariff does.

A: The Transmission Service Charge Adjustment Rider ("TSCA") completes three tasks. First, TSCA calculates the Retail Annual Transmission Revenue Requirement ("RATRR") for the test year in this Docket. The ATRR developed in the Formula Rate Template is reduced by revenues received from non-native load usage of the transmission system. In the test year, the ATRR for the Company was $5,550,089. The retail share of the ATRR was $3,518,354 (RATRR).

Q: Please explain the second task completed by the TSCA.

A: The second task is the calculation of the Transmission Service Charge in the test year for each rate class. Once the RATRR is calculated, it is allocated to the retail customer classes via the 12CP allocator. The percent of retail allocation allotted to each rate class is shown in Column 2 of the table under the "Calculation of the Transmission Service Charge". The result is the transmission revenue requirement for each rate class. Dividing the class transmission revenue requirement by the normalized test year kWh sales (Column 3) yields the Transmission Service Charge by rate class (Column 4). On the last row of the table, the average retail Transmission Service Charge for the test year is calculated by dividing the full RATRR by the adjusted test year retail sales, $0.002950/kWh.

Q: Please explain the final task completed by the TSCA.

A: After establishing the total retail and individual class Transmission Service Charges for the test year, the basis is established to adjust the rate in future years. The third task of the TSCA is to provide a mechanism to adjust the Transmission Service Charges by retail customer class. The mechanism is driven by the Formula Transmission Template (Annex 1) with the data in the Company's FERC Form 1. As the ATRR is recalculated, so is the retail share (RATRR), and a new average retail Transmission Service Charge. If the average retail Transmission Service Charge is different than that established in the test year ($0.002950), then the adjustment to each rate class for the subsequent year is a change equal to the difference between the new calculation of the average retail Transmission Service Charge and that established in the test year.

Q: Does the TSCA ensure that the RATRR is neither over nor under recovered?

A: Yes. The Company will track its recovery of transmission system costs via its Transmission Service Charges. Total recovery of the prior year transmission revenue requirement will be compared to the prior year revenue recovery. Over or under recoveries of the RATRR – including those caused by FERC adjustments to the formula calculated ATRR - will act as an increase or decrease to the succeeding year's RATRR. In this way Transmission Service Charges are increased or decreased in the next year to reflect deviation from the revenue requirement each year.

COMMENTS ON ENERGY EFFICIENCY

Q: Please comment on Midwest Energy's increasing efforts regarding energy efficiency.

A: Midwest Energy is embracing a more aggressive approach to implementing cost effective energy efficiency services on behalf of its customers. In order to embark in this new direction, a considerable amount of effort has been devoted to determine the areas of greatest potential. To start, Midwest Energy engaged the services of the Applied Energy Group (AEG) to complete a study of energy efficiency in Midwest Energy's service area. The purpose of this study was to determine the Technical, Economic, and Market (Achievable) Potential for energy conservation. In particular, the study looked at potential by class of customer and by end-use.

Q: What were the results?

A: With aggressive conservation efforts, Midwest Energy could save approximately 40,000 MWh per year (about 2.8 percent of its annual sales volumes). The greatest potential for savings is in the small commercial and residential classes. Electricity end-uses with the greatest potential are lighting and space conditioning.

Q: Is Midwest Energy utilizing this information to develop new energy efficiency programs?

A: Yes. Midwest Energy is already recognized as a leader in promoting energy efficiency to our customer-owners. But, as costs rise and the ability to acquire cost effective capacity resources declines, the Company believes it must increase efforts in this area. Midwest Energy has engaged the firm Market Development Group to assist the Company in writing business plans to expand existing programs or develop new programs.

Q: What about the How$mart℠ program?

A: Midwest Energy has developed an innovative program with assistance from Staff, CURB, and approval and encouragement from the Commission. The purpose of How$mart℠ is to remove market barriers from cost effective investments in energy efficiency. One of the business plans currently being written addresses the expansion of the How$mart℠ program beyond the four county pilot program that currently exists.

Q: Are the costs of expanding the How$mart℠ program or any other energy efficiency programs included in the adjusted test year expenses?

A: The Company has included as part of its pro forma adjustments to labor for an additional employee and associated equipment as modest increases associated with energy efficiency efforts. These adjustments are embedded in the Labor and Common Plant adjustments sponsored by Company witness Tom Meis.

Q: Does this conclude your testimony?

A: Yes.

Exhibit__(Volker-1)

MIDWEST ENERGY, INC.
TEST YEAR ENDED JUNE 30, 2007
WEATHER NORMALIZATION STATISTICAL ESTIMATION SUMMARY

	Customer Class	HDD Sensitivity[2]		CDD Sensitivity[1]		Precip Sensitivity[3]		Adjusted
		kWh/HDD	T-Stat	kWh/CDD	T-Stat	kWh/Inch	T-Stat	R-Square
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
M System	Regular Residential	2,620	5.08	79,267	23.58			92.84%
	All Electric Residential	846	34.07	1,971	13.67			95.17%
	Small C&I (GSS)	551	3.09	10,226	9.01			64.38%
	Small C&I (LGS)			4,268	3.44			88.66%
	Large General Service (>1 MW)			2,345	9.24			72.33%
	Special Contract	656	4.95					80.60%
	Irrigation					-393,227	-2.72	98.14%
W System	Regular Residential	1,054	4.11	21,383	12.81			85.28%
	Peak Residential	284	22.75	1,131	11.82			95.44%
	Small C&I Large			3,568	5.31			87.09%
	Large Power	792	3.79					54.16%
	Irrigation			7,031	6.77			95.59%
	Total System	6,803		131,189		-393,227		

1. CDD Sensitivity defined - for an average daily temperature change of -1 degree farrenheit, energy usage changes by the listed amount.

2. HDD Sensitivity defined - for an average daily temperature change of +1 degree farrenheit, energy usage changes by the listed amount.

3. Precip Sensitivity defined - for an monthly increase of precipitation of 1inch, energy usage changes by the listed amount.

Exhibit__(Volker-2)

MIDWEST ENERGY, INC.
TEST YEAR ENDED JUNE 30, 2007
WEATHER NORMALIZATION VOLUME ADJUSTMENT

Customer Class	HDD Sensitivity kWh/HDD (1)	Abnormal HDD's (2)	HDD Adjustment (kWh) (3)	CDD Sensitivity kWh/CDD (4)	Abnormal CDD's (5)	CDD Adjustment (kWh) (6)	Precipitation Sensitivity kWh/Inch (7)	Abnormal Precip (8)	Precipitation Adjustment (kWh) (9)	Total Weather Normalization Volume Adj. (kWh) (3)+(6)+(9)=(10)
M System Residential	3,466	233.1	808,007	81,238	(83.5)	(6,780,643)		(4.5)		(5,972,636)
Small C&I	551	233.1	128,478	14,494	(83.5)	(1,209,759)		(4.5)		(1,081,281)
Large C&I		233.1		2,345	(83.5)	(195,715)		(4.5)		(195,715)
Trans Level Service		233.1			(83.5)			(4.5)		
Oil Field		233.1			(83.5)			(4.5)		
Irrigation		233.1			(83.5)		-393,227	(4.5)	1,774,222	1,774,222
Lighting		233.1			(83.5)			(4.5)		
Special Contracts	656	233.1	152,873		(83.5)			(4.5)		152,873
Total M System	4,673		1,089,359	98,076		-8,186,117	-393,227		1,774,222	-5,322,536
W System Residential	1,337	233.1	311,768	22,513	(83.5)	(1,879,103)		(4.5)		(1,567,336)
Small C&I		233.1		3,568	(83.5)	(297,816)		(4.5)		(297,816)
Public Schools		233.1			(83.5)			(4.5)		
Large C&I	792	233.1	184,721		(83.5)			(4.5)		184,721
Oil Field		233.1			(83.5)			(4.5)		
Irrigation		233.1		7,031	(83.5)	(586,863)		(4.5)		(586,863)
Lighting		233.1			(83.5)			(4.5)		
Total W System	2,130		496,489	33,112		(2,763,782)	0		0	-2,267,293
Interdepartmental	0		0	0		0	0		0	0
Total	6,803		1,585,848	131,189		(10,949,899)	(393,227)		1,774,222	(7,589,829)

Exhibit__(Volker-3)

MIDWEST ENERGY, INC.
TEST YEAR ENDED JUNE 30, 2007
WEATHER NORMALIZATION REVENUE AND ENERGY SUPPLY COST ADJUSTMENT

		Booked Test Year Volume 6/30/2007 (1)	Total Weather Normalization Volume Adj. (kWh) (2)	Average Margin Rate (3)	Weather Adjustment to Margin Revenue (2)x(3)=(4)	Incremental Purchased Power (5)	**Adjustment #8** Additional Purchased Power Cost/Revenue (2)x(5)=(6)	**Adjustment #2** Total Weather Adj. to Revenue (4)+(6)=(7)
M System	Residential	236,725,513	(5,972,636)	$ 0.0236	$ (140,877)	$ 0.0500	$ (298,632)	$ (439,508)
	Small C&I	236,758,831	(1,081,281)	0.0410	(44,318)	0.0500	(54,064)	(98,383)
	Large C&I	21,089,700	(195,715)	0.0293	(5,732)	0.0500	(9,786)	(15,518)
	Trans Level Service	34,150,816		0.0068		0.0500		
	Oil Field	253,707,318		0.0212		0.0500		
	Irrigation	50,653,060	1,774,222	0.0379	67,220	0.0500	88,711	155,931
	Lighting	6,543,264		0.0410		0.0500		
	Special Contracts	58,483,156	152,873	0.0100	1,529	0.0500	7,644	9,172
	Resale	92,790,487						
	Total M System	990,902,144	(5,322,536)		$ (122,178.23)		$ (266,126.79)	$ (388,305.03)
W System	Residential	70,753,186	(1,567,336)	$ 0.0222	$ (34,816.79)	$ 0.0500	$ (78,366.78)	$ (113,184)
	Small C&I	90,235,447	(297,816)	0.0140	-4,167	0.0500	(14,891)	(19,058)
	Public Schools	5,137,003		0.0270		0.0500		
	Large C&I	82,089,220	184,721	0.0143	2,640	0.0500	9,236	11,876
	Oil Field	37,456,423		0.0140		0.0500		
	Irrigation	9,121,619	(586,863)	0.0140	-8,211	0.0500	(29,343)	(37,554)
	Lighting	3,726,521		0.0410		0.0500		
	Resale	81,064,116						
	Total W System	379,583,535	(2,267,293)		$ (44,554)		$ (113,365)	$ (157,919)
	Interdepartmental	102,104		$ 0.0410		0.0500		
	Total	1,370,587,783	(7,589,829)		$ (166,733)		$ (379,491)	$ (546,224)

MIDWEST ENERGY, INC
ELECTRIC DEP'T
TEST YEAR ENDED JUNE 30, 2007
Allocation of Account 555

[1] ** CONFIDENTIAL ** M SYSTEM	[2] ** CONFIDENTIAL ** TYPE PURCHASE	[3] Capacity Provided	[4] Annual Capacity Charges	[5] Adjusted Energy Provided	[6] Adjusted Annual Energy Chrg	[7] Total Purchased Power
[redacted]		125,000	$9,969,996	316,564,808	$5,944,653	$15,914,649
			328,633			328,633
		1,500	41,817	2,900,000	47,276	89,093
		3,300	29,850	0	0	29,850
		0	0	57,817,095	2,601,769	2,601,769
		67,000	10,251,000	586,920,000	10,271,100	20,522,100
		30,000	1,800,000	2,628,000	210,240	2,010,240
			42,015			42,015
			355,042			355,042
			260,117			260,117
						0
						0
			507,508			507,508
Total M System Retail Account 555		226,800	$23,585,979	966,829,903	$19,075,038	$42,661,017
W SYSTEM						
[redacted]		4,000	$162,000	0	0.00	$162,000
		33,000	5,049,000	289,080,000	5,058,900	10,107,900
		20,000	1,200,000	7,015,180	561,214	1,761,214
		0	0	18,832,905	847,481	847,481
			124,967			124,967
			94,988		0	$94,988
Total W System Retail Account 555		57,000	$6,630,955	314,928,085	$6,467,595	$13,098,550
Total Company RETAIL Purchased Power Cost Total - Capacity		283,800	$30,216,934	1,281,757,988	$25,542,633	$55,759,567
GMEC Energy and Capacity		75,600		52,980,480		
		359,400		1,334,738,468		
	Check: Adjusted Retail Sales Vol.	1,192,795,771				
	x Line Loss Factor	1.119				
	Energy Required @ System Input	1,334,738,468				
	Replacement Power Costs - Phase 1 of GMEC Only	25,200	$126,000	17,660,160	$1,412,813	$1,538,813
	M System Allocation - 75.43%	19,008	$95,042	13,321,059	$1,065,685	$1,160,726
	W System Allocation - 24.57%	6,192	$30,958	4,339,101	$347,128	$378,086

MIDWEST ENERGY, INC
ELECTRIC DEP'T
TEST YEAR ENDED JUNE 30, 2007
Fuel Cost Calculation - GMEC

1	Capacity	75,600	kW		
2	Heat Rate	8,500	Btu per kWh		
3	Hours of Operation	700.8	Hours (8%)	52,980,480	kWh generation - Full Integration
4				35,320,320	kWh generation - Phase 1 only
5					
6	MMBtu's of Gas	450,334	MMBtu's (from formula on row 8) - Full Integration		
7		300,223	MMBtu's (from formula on row 8) - Phase 1 only		
8					
9	(Capacity) x (Heat Rate) x (Hours of Operation) x (MMBtu/1 Million Btu) = MMBtu's of Gas				
10					
11	Fuel Price Estimate	$7.00	per MMBtu (delivered)		
12					
13	Total Fuel Cost (5) x (10)		$3,152,339 Full Integration		
14			$2,101,559 Phase 1 only		
15					
16	Fuel Cost per kWh		$0.0595		