STATE OF SOUTH DAKOTA

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

MIDAMERICAN ENERGY COMPANY	**)**	
	)	**DOCKET NO. EL14-_____**
Proposed General Increase in	**)**	
Electric Rates	**)**	

DIRECT TESTIMONY
OF
CHARLES B. REA

Q. Please state your name and business address.

A. My name is Charles B. Rea. My business address is MidAmerican Energy Company ("MidAmerican"), 106 East Second Street, Davenport, Iowa 52801.

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

A. I am employed by MidAmerican as Manager, Regulatory Strategic Analysis.

Q. Please describe your education and business experience.

A. I received a B.A. in Computer Science from the University of Illinois at Springfield in 1986 and a M.A. in Statistics and Operations Research from Southern Illinois University at Edwardsville in 1990. I have been employed by MidAmerican and its predecessor companies since 1990 and have worked in electric system planning, forecasting, load research, marketing, rates, and energy efficiency.

Q. Have you testified before the South Dakota Public Utilities Commission ("Commission") or other regulatory bodies previously?

A. Yes, I have testified before the Commission in Docket No. GE12-005. I have also testified before the Iowa Utilities Board and the Illinois Commerce Commission concerning energy efficiency, gas and electric cost of service, rate design, and weather normalization issues.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to sponsor MidAmerican's electric cost of service analysis and the calculation of MidAmerican's proposed electric rates in this docket. In addition, I am sponsoring MidAmerican's weather normalization pro forma adjustment for electric sales and revenue.

Q. Are you sponsoring any exhibits in the filing?

A. Yes. I am sponsoring Exhibit CBR 1.1, which includes the following schedules:

- Schedule A: Electric Cost of Service Functional Allocators
- Schedule B: Hourly Costing Model
- Schedule C: Electric Cost of Service Results
- Schedule D: Derivation of Electric Rates
- Schedule E: Proposed Electric Rates
- Schedule F: Electric Weather Normalization Pro Forma
- Schedule G: Electric Weather Normalization Methodologies

Q. How is your direct testimony organized?

A. My direct testimony is organized in three sections:

1. Electric Cost of Service Model
2. Rate Design Considerations and Methods
3. Electric Weather Normalization

<u>Electric Cost of Service Model</u>

Q. What is a cost of service analysis?

A. A cost of service analysis is a study that determines the cost of providing electric service to the utility's various customer groups for the purpose of setting prices. A cost-based price signal for electric service is important because it provides consumers with important information and is the basis for their purchase and investment decisions regarding energy consumption. Basing prices on cost of service helps realize two important goals in utility ratemaking:

1. Consumers would use electricity at an economically efficient level.

2. No consumer's electric service would be subsidized by any other consumer.

The provision of electric service requires that many common and joint costs be incurred to supply service to multiple customers. The collection of information that would allow individual consumer cost determination is prohibitively expensive and not cost-effective except for the largest customers. This has required the development of allocation methodologies to assign these common costs to customer groups. Historically, similar types of customers have been combined into customer groups for the process of cost determination and ratemaking. The resulting cost determination process based on the allocation of costs to defined customer groups is called a cost of service study.

Q. Please describe MidAmerican's approach to electric cost of service.

A. MidAmerican's cost of service analysis is a two-stage analysis. The first component of the cost of service analysis assigns MidAmerican's revenue requirement to business function on an account-by-account basis. Some accounts are assigned entirely to a single function, while other accounts are assigned to multiple functions based on an allocation methodology. The result of this first phase of cost of service is a revenue requirement for each function, the sum of which totals to MidAmerican's total revenue requirement.

The second component of the cost of service analysis assigns the revenue requirement for each function to customer class using a single and separate allocation methodology. The result of the second phase of cost of service is a revenue requirement for each customer class, the sum of which also totals to MidAmerican's total revenue requirement.

Q. What are the various business functions that MidAmerican assigns its revenue requirements to in the first stage of the electric cost of service analysis?

A. MidAmerican assigns revenue requirements in the first stage of the cost of service analysis to the following business functions:

- Generation
- Transmission
- Substations
- Three-phase wires
- Single-phase wires
- Transformers
- Services
- Meters
- Customer accounts
- Lighting

Q. Please describe how individual accounts that make up MidAmerican's revenue requirement are assigned to function.

A. The majority of the accounts that make up MidAmerican's revenue requirement are directly assigned to a single function. Examples of this include generation plant and operations and maintenance (O&M) expenses that are all assigned to the generation function, transmission plant and O&M expenses, which are all assigned to the transmission function, and distribution plant and O&M expenses, which are all assigned to the distribution function, although within the distribution function, further assignments are made between substations, wires, and other distribution functions.

Accounts not directly assignable to a single function are allocated between functions based on appropriate allocation factors. Examples of this include general and intangible plant, miscellaneous rate base deductions, administrative and general (A&G) expenses, and payroll taxes. These accounts are allocated to functions based on the net plant or payroll dollars associated with each function, depending on the account.

Q. Do you have a schedule that shows how each account is allocated to function?

A. Yes. Schedule A identifies each account in the functional cost of service analysis, whether that account is direct assigned or allocated, and if allocated, the specific method used to allocate that account. In addition, the schedule shows the percentage of each account that is assigned or allocated to each business function.

Q. What are the results of MidAmerican's functional cost of service analysis?

A. The breakdown of revenue requirements across functions in MidAmerican's electric cost of service analysis is shown below:

- Generation: $9,888,240 (75.7%)
- Transmission: $832,362 (6.4%)

- Substations: $511,316 (3.9%)
- Three Phase Wires: $722,317 (5.5%)
- Single Phase Wires: $406,303 (3.1%)
- Transformers: $126,418 (1.0%)
- Services: $199,112 (1.5%)
- Meters: $68,099 (0.5%)
- Customer Accounts: $205,273 (1.6%)
- Lighting: $97,245 (0.7%)

Q. What are the customer classes that MidAmerican assigns its functional revenue requirements to in the second stage of the cost of service analysis?

A. MidAmerican assigns revenue requirements from the first stage of the cost of service analysis to the following customer classes:

- Residential
- Small General Service – Energy
- Small General Service – Demand
- Large General Service (LGS)
- Very Large General Service (VLGS)
- Lighting
- Municipal Water Pumping

Q. What methods for allocating generation costs to customer class are MidAmerican using in its cost of service analyses?

A. MidAmerican's methodology for allocating generation costs to customer class is referred to as the Hourly Costing Model (HCM).

Q. Please describe the HCM.

A. The HCM is a method for pricing generation service to retail customers. The HCM prices generation service on a non-discriminatory basis based on customer load shapes and usage patterns, and the cost of producing generation at different times of the day and different times of the year.

Q. How does the HCM methodology work?

A. The goal of the HCM methodology is to assign a price for generation to each hour of the year. The generation revenue requirement assigned to each customer class under this methodology results from applying each class' hourly load profile to the hourly price profile generated by the HCM (loads multiplied by prices). The ratio of total generation cost resulting from this cross-multiplication of loads and prices for a single class to the total generation cost for all classes is then used to allocate MidAmerican's generation-related revenue requirements to customer class. A graphical representation of the HCM methodology is provided in Schedule B.

Q. How does the HCM methodology assign a price for generation to each hour of the year?

A. The HCM calculates a generation price for each hour of the year by assigning a cost to each MWh in the retail system load curve. For any given hour, the HCM methodology calculates the average of the costs for all MWh in that hour to determine the average generation price for that hour.

Q. How does the HCM determine a cost for each MWh in the retail system load curve?

A. Each MWh in the retail system load curve is assigned a cost that contains two components; an energy component and a capacity component. Schedule B shows graphically how the cost assignment process works.

The energy component of each MWh is determined by the Midcontinent Independent System Operator, Inc. Locational Marginal Price ("MISO LMP") for the MidAmerican retail load zone node associated with the hour of the year the MWh is produced. This price is then adjusted downward to an amount that reflects MidAmerican's total retail fuel cost for the test year. For example, on July 23, 2013 at hour ending 10 a.m., the MISO LMP price for MidAmerican's pricing node is $34.07/MWh, and the adjustment multiplier for all hours is 0.39729. All MWh in the retail system load curve associated with the hour of July 23, hour ending 10 a.m. will have an energy component of $13.54/MWh, or 1.354 cents/kWh. This figure is calculated by multiplying the $34.07/MWh LMP price by 0.39729.

The capacity component of each MWh is determined by the level of South Dakota retail load the MWh is serving, the number of hours during the year that retail load is at or above that level, and the capacity cost on a $/kW basis used to serve that load level. For example, at a retail load level of 30 MW, the capacity component for all MWh serving that level of retail load is $144.84/MWh, or 14.484 cents/kWh. This is based on the following:

- Capacity Cost at the 30 MW load level is $185.69/kW
- South Dakota retail system load is at or above 30 MW for 1,282 hours of the year

- $185.69/kW divided by 1,282 hours = 14.484 cents per kWh, or $144.84/MWh

The effect of defining a capacity component in the manner outlined above is to spread the fixed costs of production capacity for any given tranche of capacity across all of the units produced by that tranche of capacity. For low levels of system load, the capacity component will be relatively small because many MWh are produced by capacity serving low levels of system load. For example, the capacity component at a South Dakota system load level of 21 MW is only $21.94/MWh or 2.194 cents/kWh because the system load is at or above 21 MW for 8,465 hours of the year. Because 8,465 MWh are produced by a MW of capacity that is operating at a system load level of 21 MW, the fixed costs of that MW of capacity can be spread over a large number of MWh, thus lowering the fixed cost per unit. For high levels of system load, the capacity component will be very large because very few MWh are produced by capacity serving high levels of system load. For a South Dakota system load level of 31 MW, the capacity component will be $204.50/MWh or 20.450 cents per kWh because the system load is at or above 31 MW for only 908 hours of the year. Because only 908 MWh are produced by a MW of capacity that is operating at a system load level of 31 MW, the fixed costs of that MW of capacity are spread over a much smaller number of MWh, thus increasing the fixed cost per unit.

MidAmerican uses $185.69/kW as the capacity cost for the HCM in all hours of the year.

Q. Why is MidAmerican using MISO LMP prices to help determine the energy component of costs for the HCM methodology?

A. MidAmerican is using MISO LMP prices to help determine the energy component of costs for the HCM model because they are directly related to the cost to MidAmerican of purchasing energy in the MISO market to serve retail customers. Because MidAmerican bids generation directly into the market and purchases from the market at MISO market prices to serve retail load, it is appropriate to use the MISO LMP data in part to determine energy prices for customer groups under the HCM methodology.

Q. Why is MidAmerican adjusting the MISO LMP prices downward to an amount that reflects MidAmerican's total retail fuel cost for the test year?

A. Because MidAmerican bids generation directly into the market and purchases from the market at MISO market prices to serve retail load, the MISO LMP price is effectively MidAmerican's marginal energy cost, which is almost always equal to or greater than MidAmerican's actual fuel cost in any hour. Because the LMP price is almost always equal to or greater than MidAmerican's actual fuel cost in any hour, using the LMP price directly as the energy component of the HCM would recover some amount of fixed cost in the energy component of the HCM. In order to completely segregate fuel costs from capacity costs in the HCM such that fuel costs are recovered through the energy component and capacity costs are recovered through the capacity component, MidAmerican adjusts the MISO LMP price downward, thus effectively allocating MidAmerican's test-year fuel costs to different hours of the year based on the varying levels of MISO LMP price.

Q. How is the capacity cost of $185.69/kW determined?

A. The capacity price of $185.69/kW represents the overall South Dakota jurisdictional embedded cost of capacity. This price is calculated by subtracting total retail fuel in the 2013 test year from the overall functionalized generation revenue requirement, and dividing that result by the South Dakota jurisdictional peak demand.

Q. Why is the HCM an appropriate method for pricing generation service to retail customers?

A. The HCM is an appropriate method for pricing generation service to retail customers for a number of reasons:

1. The HCM methodology rewards customer groups whose load characteristics, load patterns, and time of use characteristics result in lower costs to serve. Customers and customer groups whose energy consumption is high at times of high system load and high costs pay higher total costs and are allocated more generation costs than customer groups whose load shapes are more favorable.
2. The HCM methodology also rewards customer groups with higher load factors. Customer groups with high load factors are allocated a lower generation cost (on a per unit basis) than customer groups with lower load factors.

3. The HCM methodology results in pricing for generation services that is non-discriminatory. The HCM results in a single average price for generation service in each hour of the year that reflects both an energy component and a capacity component. All customers that are taking generation service in any given hour pay the same price per kWh under the HCM model for that generation service regardless of size or end use. Stated differently, at any given point in time, the cost of generation service is the same to every customer on the system regardless of size or end use, which is exactly how the generation portfolio operates and how generation markets work.
4. The HCM model is both a de facto cost allocation model and a pricing model. Unlike traditional cost allocation methodologies, results from the HCM model can be used directly in the ratemaking process. Because generation prices are available from the HCM model by hour, prices can be summarized by season or time of use pricing period and translated directly into seasonal and time of use retail rates. This is a feature that is not supported in traditional cost allocation methodologies.
5. Results from the HCM model are more stable from year to year than traditional generation cost methodologies because the HCM model considers energy consumption patterns all through the year, as opposed to traditional methods that rely on a single hour's demand reading that can change significantly from year to year.

Q. Has the HCM been approved in other states for generation cost of service?

A. Yes. The HCM has been accepted for generation cost of service by the Iowa Utilities Board in MidAmerican's electric rate case Docket No. RPU-2013-0004. The HCM has also been supported in testimony of the Illinois Commerce Commission staff and is currently being reviewed by the Illinois Commerce Commission in MidAmerican's electric rate case Docket No. 14-0066.

Q. What methods for allocating transmission costs to customer class is MidAmerican using in its cost of service analyses?

A. MidAmerican is using a 12 Coincident Peak ("12 CP") methodology for allocating transmission costs to customer class.

Q. Please describe the 12 CP method.

A. The 12 CP method allocates transmission costs to customer class based on each class' load at the time of MidAmerican's monthly system peak demand. For each class, the class load at the time of the monthly system peak (referred to as the class coincident peak) is recorded and the total is calculated across all 12 months. The total calculated across all 12 months is referred to as the 12 CP value. Each class is then allocated a piece of MidAmerican's transmission revenue requirement based on the ratio of that class' 12 CP value to the sum of the 12 CP values for all customer classes.

Q. What are the advantages of the 12 CP method?

A. The primary advantage of the 12 CP method is that the allocator is a good reflection of how MidAmerican incurs transmission costs within the MISO footprint. Generally speaking, MidAmerican is assessed costs for transmission services in MISO based on what is referred to as a "load ratio share", which is

MidAmerican's native load at the time of MISO's monthly peak demand. The 12 CP method is a simple extension of that concept and allocates costs to customers based on their loads at the time of MidAmerican's monthly peak demand.

Because MidAmerican incurs costs for transmission service from MISO in this fashion, it is appropriate to pass these costs on to customers in the same fashion. In addition, using the 12 CP allocator helps to ensure consistency between unbundled transmission prices offered by MidAmerican and transmission costs customers could expect to see from third party suppliers who will also incur transmission costs in MISO based on a load ratio share.

Q. Please describe how MidAmerican allocates the revenue requirement associated with distribution wires to customer class.

A. Distribution wires costs are allocated to customer groups based on a non-coincident peak demand allocator and a split-system approach to distinguishing the distribution system between three-phase and single-phase service.

Q. How are distribution wires costs allocated to customer class under the split system methodology?

A. Under the split system methodology, the wires component of distribution revenue requirements is split into separate single-phase and three-phase components and each is allocated to customer classes separately. For the three-phase component, costs are allocated to customer classes based on each customer class' annual non-coincident peak demand, where the ratio of an individual customer class' annual maximum load to the sum of all class' annual maximum loads. Allocations are made in this way to all classes except for the VLGS class, which generally takes service directly at the substation level. Costs for the single-phase component are allocated to customer class in exactly the same way as for the three-phase component except for the single-phase component, both the VLGS and LGS classes are excluded because the LGS class takes service directly from the three-phase distribution system.

Q. How is the total revenue requirement associated with distribution wires split between three-phase and single-phase components?

A. The total revenue requirement associated with distribution wires is split between three-phase and single-phase based on weighted average costs. The total installed circuit footages were determined for three-phase and for single-phase. The footages for each were multiplied by the average cost per foot, respectively. The portion of weighted average three-phase wire cost was compared to the total to arrive at the allocation to three-phase wires.

Q. Please describe how MidAmerican allocates the revenue requirement associated with substations to customer class.

A. Substation costs are allocated to customer groups based on a non-coincident peak demand allocator, where the ratio of an individual customer class' annual maximum load to the sum of all class' annual maximum loads is used to allocate a portion of the substation revenue requirement to that class.

Q. Please describe how MidAmerican allocates the revenue requirement associated with transformers to customer class.

A. Transformer costs are allocated to customer classes based on a weighted number of customers calculation. Customer weights in each class are calculated based on the ratio of the current average cost of transformation (per customer) required to serve particular customer groups to the current average cost of transformation for residential base customers.

Q. Please describe how MidAmerican allocates the revenue requirement associated with services to customer class.

A. Service costs are allocated to customer classes based on a weighted number of customers calculation. Customer weights in each class are calculated based on the ratio of the current average cost of service drops (per customer) required to serve particular customer groups to the current average cost of service drops for residential base customers.

Q. Please describe how MidAmerican allocates the revenue requirement associated with meters to customer class.

A. Metering costs are allocated to customer classes based on a weighted number of customers calculation. Customer weights in each class are calculated based on the ratio of the current average cost of metering (per customer) required to serve particular customer groups to the current average cost of metering for residential base customers.

Q. Please describe how MidAmerican allocates the revenue requirement associated with the customer accounts function to customer class.

A. Customer account costs are allocated to customer classes based on a weighted number of customers calculation. Customer weights in each class are calculated based on the ratio of the current cost of providing customer service and key account management functions (per customer) to particular customer groups to the current cost of providing customer service functions to residential base customers.

Q. Please describe how MidAmerican allocates the revenue requirement associated with lighting to customer class.

A. The revenue requirement associated with lighting is 100% direct assigned to the lighting customer class.

Q. What are the results of MidAmerican's cost of service study?

A. Schedule C shows the results of MidAmerican's cost of service analysis. Schedule C contains both the allocation of revenue requirements to function and the allocation of the costs associated with each function to customer class.

Q. Has MidAmerican provided a copy of its electric cost of service study?

A. Yes. A full and complete working copy of MidAmerican's electric cost of service and rate design model has been provided as a workpaper to Statement O in the electric filing requirements.

Rate Design Considerations and Methods

Q. Please describe the relationship between cost of service results and the goals of rate design.

A. An important goal of rate design is to develop prices for electric service to retail customers that are intended to recover the Company's approved revenue requirement and that reflect the cost of providing service to retail customers. However, that goal must be tempered by considerations of impacts to customers. As a result, MidAmerican proposes to limit the increase to any customer class to no more than 150% of the overall increase percentage. This limitation would apply to increases for the LGS and VLGS classes. The costs not recovered from those two classes are assigned to other classes in proportion to their total cost of service. The results of this re-assignment are included on Schedule C.

MidAmerican has calculated a full set of rates based upon the cost of service analysis provided in this case. MidAmerican's proposed rates reflect the costing and pricing principles that were used to develop the cost of service study. Detailed financial information from the cost of service analysis is used to develop the individual components of the rate design. The generation rate component is then adjusted to reflect the class increase limitations.

Q. What rates is MidAmerican proposing to implement in this case?

A. As outlined in the testimony of Debra Kutsunis, MidAmerican is proposing to consolidate rates among current rate codes and proposes to implement single rates for the following rate classes:

- Residential (RS)
- General Service Energy (GE)
- General Service Demand (GD)
- Large General Service (LS)
- Substation Service (SS)
- Street and Area Lighting (SAL)
- Municipal Water Pumping (MWP)

MidAmerican is proposing to implement a standard tariff rate for each of the customer classes mentioned above, plus optional time-of-use rates for Rates RS, GE, GD, LS and SS.

Q. How are the various cost components of the class cost of service study used in the design of MidAmerican's proposed unbundled rates?

A. Schedule D shows the derivation of rates for each of MidAmerican's proposed rates. It maps out for each rate how the different components of cost of service are used to build the rate.

Q. Do you have a schedule that shows MidAmerican's proposed rates?

Schedule E provides a complete set of proposed rates for MidAmerican in this filing. The rates in Schedule E include test year levels of EAC and TCR.

Electric Weather Normalization

Q. What is the purpose of the electric weather normalization pro forma and why is it an important issue in this case?

A. MidAmerican estimates that about 30% of electricity sold to residential customers is used for cooling and heating and is therefore weather dependent. As a result, the level of annual revenue that is collected from volumetric charges associated with this electricity usage is dependent on how hot or mild the summer season is, and how cold or mild the winter season is. Hot summers and cold winters will result in MidAmerican collecting a higher level of revenue than it normally otherwise would, and mild summers and winters will result in MidAmerican collecting a lower level of revenue. The purpose of the weather normalization pro forma adjustment is to determine a level of retail sales and revenues under existing rates that could be reasonably expected given normal weather conditions, thus eliminating the effect on test year retail sales and revenues of having unusually mild or extreme weather during the test year.

Q. What classes is MidAmerican proposing to include in the weather normalization pro forma adjustment?

A. MidAmerican is proposing weather normalization pro forma adjustments for the following residential rate classes:

- Rate RBD
- Rate RED
- Rate RSD
- Rate RWD

Q. What is the value of the proposed weather normalization pro forma adjustment?

A. The weather normalization pro forma adjustment reduces total test year revenue by $120,606. The weather normalization pro forma adjustment for both revenue and kWh sales by class is provided in Schedule F.

Q. What weather data is MidAmerican using as the basis for the pro forma adjustment?

A. MidAmerican is basing its weather normalization adjustment for electric sales on daily weather data from the NOAA Sioux City, Iowa weather station. This is the most appropriate weather station, as MidAmerican's South Dakota service territory is all located in southeastern South Dakota, primarily in close proximity to Sioux City. Daily heating degree days with a 55 degree base are used to model the heating component of weather-sensitive sales, and daily cooling degree days with a 65 degree base are used to model the cooling component of weather-sensitive sales. Normal weather is defined to be the official 30-year NOAA daily normal (1981-2010) for Sioux City.

Q. Please describe the methodology MidAmerican is using to determine the sales component of the weather normalization pro forma.

A. MidAmerican's weather normalization methodology for normalizing annual electric sales by customer class is provided in Schedule G.

Q. Please describe the methodology MidAmerican is using to determine the revenue component of the weather normalization pro forma.

A. MidAmerican's methodology for determining the revenue component of the weather normalization pro forma adjustment is also provided in Schedule G.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.