FILED WITH
Executive Secretary
February 01, 2013
IOWA UTILITIES BOARD

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	)	
	)	**DOCKET NO. EEP-2012-0002**
MIDAMERICAN ENERGY COMPANY	)	
	)	

DIRECT TESTIMONY
OF
JENNIFER L. LONG

Q. Please state your name and business address.

A. Jennifer L. Long. 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 Engineer II-Electric System Planning.

Q. Please describe your educational and business experience.

A. I graduated from Iowa State University in 2009 with a Bachelor of Science degree, majoring in Electrical Engineering. I begin my employment with MidAmerican in 2010 as an Engineer in the Electric System Planning Department. I am a member of the Institute of Electrical and Electronics Engineers.

Q. What are your principal responsibilities at MidAmerican?

A. My present duties include the development of short and long range plans for electric transmission line and transmission substation expansion projects and electric distribution line and distribution substation expansion projects in the Council Bluffs, Knoxville and Oskaloosa areas. I support the development of the 10-year electrical engineering capital

forecast for the Council Bluffs, Knoxville and Oskaloosa areas, including the development of planning and capital budget studies demonstrating need and establishing the priority of Council Bluffs, Knoxville and Oskaloosa capital projects. I conduct computer-based system power flow, voltage flicker, reliability and economic analysis studies.

Q. Have you testified before Iowa Utilities Board or other regulatory bodies previously?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor part of the information MidAmerican is required to file under 199 IAC Section 35.9(7), Avoided Electric Capacity and Energy Costs.

Q. Are you sponsoring any exhibits in the filing?

A. Yes. I am sponsoring Exhibit___(JLL-1), which includes the following schedules regarding MidAmerican's avoided cost calculations:

- Schedule 1: Avoided Cost Calculation - Transmission
- Schedule 2: Avoided Cost Calculation - Distribution

Q. What filing requirements contained in 199 Iowa Administrative Code 35.9(7) does your testimony address?

A. My testimony describes the methodology, calculation and results for determining avoided transmission and distribution (T&D) costs.

Q. Do the current Iowa administrative rules concerning energy efficiency plan filings include a requirement to supply avoided T&D costs?

A. No, it is my understanding that the rules do not require the filing of avoided T&D costs. However, the rules do allow for filing an "alternative method." Section 35.9(7) includes a statement that "[a] party may submit, and the board shall consider, alternative avoided capacity and energy costs derived by an alternative method. A party submitting alternative avoided costs shall also submit an explanation of the alternative method." The avoided T&D costs submitted in my testimony and outlined in Exhibit___(JLL-1), Schedule 1 and Schedule 2, should be considered an alternative method of computing avoided capacity and energy costs. These avoided T&D costs are to be added to the avoided capacity costs that are included in the testimony of MidAmerican witness O. Dale Stevens and presented in Exhibit___(ODS-1), Schedule 10. The resultant totals are shown in Exhibit___(ODS-1), Schedule 11.

Q. Why has MidAmerican prepared avoided T&D costs?

A. MidAmerican has prepared avoided T&D costs because additional capacity demand on the T&D system may cause a need for system improvements. A reduction in the growth of system demand may delay the need for system improvements and therefore may have the benefit of avoiding these future transmission and distribution related costs.

Q. What characteristics should a methodology to calculate avoided T&D costs have?

A. Given the complexity of identifying precise impacts of T&D load reductions, a fundamental aspect of an avoided cost methodology is that it should estimate the average avoided cost per kW associated with load reductions. A methodology for estimating avoided cost should have the following features:

- Estimate actual average system avoided T&D cost, and
- Be transparent and reproducible.

Q. Please explain the methodology that MidAmerican used to calculate avoided T&D costs and identify the results of the calculation.

A. The determination of T&D avoided costs for the MidAmerican system is broken down into calculations for the transmission component and the distribution component of the energy delivery system. The average cost to serve existing load is calculated for both the transmission and distribution systems by dividing each system's net cost by each system's peak capability. MidAmerican's Federal Energy Regulatory Commission (FERC) Form 1 data is used to calculate the net costs of the transmission and distribution systems by taking MidAmerican's original cost of plant less accumulated depreciation for each respective system. Yearly, MidAmerican load data and generation capability data is used to approximate the capacity of each system. The end result of the calculation is a $/kW cost for each system.

MidAmerican T&D avoided costs are calculated using depreciated original cost figures listed in FERC Form 1. These figures are used to calculate the net cost per kW of capacity on the transmission and distribution systems respectively. This cost is then spread across the average book-life of the transmission system (43 years) or distribution system (35 years), using the economic recovery method. This process results in a calculation of MidAmerican's yearly T&D avoided cost. Using MidAmerican economic data and data from FERC Form 1, as shown in Exhibit___(JLL-1), Schedule 1 for transmission or Schedule 2 for distribution, the year-one economic recovery rates were calculated to be 4.72 percent and 5.16 percent respectively.

Original cost depreciated of the MidAmerican transmission system is calculated from data located in FERC Form 1, submitted annually by MidAmerican to FERC.

The 2011 year-end balance of the total original cost for the MidAmerican transmission system is $750,515,936, which includes both depreciable and amortizable assets. Therefore, to obtain the system net cost, the transmission system accumulated depreciation, $272,083,822 at year-end, and the accumulated amortization, $0 at year-end, must both be deducted from the original cost. Subtracting accumulated depreciation and amortization from original cost results in a net cost of $478,432,114 for the MidAmerican transmission system.

Since the purpose of the transmission system is to provide a path for power flow from the generators to the distribution system, the capacity of the transmission system is assumed to be equal to the total generation that MidAmerican has available to serve its peak load. The 2011 report listed MidAmerican as having 5,319 MW of available generation capacity in July 2011. MidAmerican has 5,319 MW of generation capacity available to serve MidAmerican load. To obtain a net cost per kW, the net cost of the transmission system is divided by the total available generation, which results in a net cost of $89.95 per kW. The 43 years of annual revenue requirements for the $89.95 per kW cost are then calculated in Exhibit___(JLL-1), Schedule 1 and result in a present value of the annual costs of $241.23. Multiplying this figure by the transmission economic recovery rate, 4.72%, results in a transmission year-one avoided cost of $11.40/kW.

The approach described to calculate the transmission avoided cost per kW is used for the distribution system as well. Original cost of the distribution system listed in 2011 FERC Form 1 is $2,432,835,111. However, this figure must be modified to calculate an avoided cost for the distribution system. The costs for “Services,” “Meters” and “Street

Lighting and Signal Systems" listed in FERC Form 1 should not be included in the figure used for calculating an avoided cost, since these costs will not change as load is reduced. They are required to serve customers with or without an energy efficiency load reduction; therefore, they are subtracted from the original cost figure. Removing the original costs of services, meters, and street lighting and signal systems, results in an adjusted distribution system cost of $2,161,275,554.

The total accumulated depreciation of the distribution system listed in the 2011 FERC Form 1 is $1,065,994,522. The accumulated depreciations of the three removed items must also be subtracted from the total accumulated depreciation. This results in an adjusted accumulated depreciation of $959,471,883. Subtracting adjusted accumulated depreciation from adjusted total distribution system cost results in a net cost of $1,201,803,671.

To find a cost per kW the net cost figure must be divided by the capacity of the distribution system. The capacity of the MidAmerican distribution system is estimated to be the system noncoincident peak load. Distribution system installations and improvements are installed to serve forecasted load by area; therefore, the noncoincident forecasted system peak load is used as an estimate of the distribution system capacity. The 2011 forecasted noncoincident peak load by area was 4,634 MW. This number includes distribution system losses occurring from the distribution substation to the customer; however, it does not include high-voltage distribution system losses. Since distribution system capacity is installed to meet the system demand plus losses, this figure must be adjusted to include high-voltage distribution system losses. Doing so results in a 2011 noncoincident peak load, including total distribution system losses, of

4,682 MW. Dividing the net cost of the distribution system by this figure results in a cost per kW of $256.69. The 35 years of annual revenue requirements for the $256.69 per kW cost are then calculated in Exhibit___(JLL-1), Schedule 2 and result in a present value of the annual costs of $628.73. Multiplying this figure by the distribution economic recovery factor, 5.16 percent, results in a distribution year-one avoided cost of $32.42/kW.

Since MidAmerican is required to maintain a 12 percent reserve generation margin for 2011-2016, a 12.2 percent reserve margin for 2017, a 12.3 percent reserve margin for 2018, a 12.5% reserve margin for 2019 and 12.6% reserve margin for 2020 and beyond, transmission capacity also is required to cover the reserve margin. Therefore, the T&D avoided cost is increased by the reserve margin factor as shown in Exhibit___(JLL-1), Schedule 1. Distribution avoided cost should not be increased by the reserve margin factor – since the distribution system is not constructed based upon generation reserve requirements. Also, neither transmission nor distribution avoided costs should be increased by an externality factor.

The avoided costs, however, are increased by a loss factor in order to calculate the benefits of energy efficiency measures. Since energy efficiency measures save energy at the customer meter, their impact on system capacity also includes losses incurred to serve loads at the meter. The transmission and distribution systems have loss factors of 1.989 percent and 6.017 percent respectively. It is appropriate to increase the transmission avoided cost estimate by the sum of the two loss factors (8.01 percent) because avoided losses on either system will free capacity on the transmission system. The distribution avoided cost estimate is only increased by the distribution system loss factor (6.017

percent) because avoided losses on the transmission system will not affect the distribution system, only avoided distribution system losses will free capacity on the distribution system. The increase in avoided T&D costs has been completed in Exhibit___(JLL-1), Schedule 1 and Schedule 2.

The calculations shown used figures from 2011. The T&D avoided costs obtained from the calculations should be escalated to 2014 in order to represent MidAmerican avoided costs associated with energy efficiency programs beginning in 2014. An escalation rate of 2.5 percent was calculated by comparing the average system net investment versus the average peak load growth over the past 13 years.

Escalating the avoided cost estimates four years by 2.5 percent results in a 2014 avoided cost for transmission of $14.85 and for distribution $37.01, yielding a total of $51.86. This value is shown in the "year 4" rows of Exhibit___(JLL-1), Schedule 1 and Schedule 2. This figure estimates total T&D avoided cost to MidAmerican associated with load reductions from energy efficiency programs.

Q: What are the major benefits of this methodology?

A. The primary benefit of this methodology is that the result will closely follow MidAmerican's actual average cost per kW of capacity on the transmission and distribution systems. In the future, the system net cost will change to reflect retirements, new installations and improvements made to the T&D system. System upgrades in T&D capacity will be followed closely by future kW demand increases and generation capability increases. Another benefit of this methodology is the ability to easily reproduce the calculation in the future because of the use of FERC Form 1 data. A third benefit with this methodology is that using original costs depreciated is consistent with

ratemaking concepts.

Q. The calculations for determining energy efficiency program cost-effectiveness require avoided costs for a 20-year period. Do you have avoided T&D costs calculated for years 2010 through and including 2028?

A. Yes, Exhibit___(JLL-1), Schedule 1, rows 5 through 43 on page 2, show the transmission avoided costs for years 2015 through 2053. Exhibit___(JLL-1), Schedule 2, rows 5 through 35 on page 2, show the distribution avoided costs for years 2015 – 2045.

Q. Do you have any concerns about the application of the avoided T&D costs to determine the cost/benefits of energy efficiency programs?

A. Yes. Some load management programs may not provide savings on the distribution system because, while they provide savings during coincident system peak, the programs may not operate during local peaks on the distribution system. For example, a residential distribution feeder or substation may peak on a hot evening, while a residential air conditioner control program would only be called into operation between 2 and 7 p.m. In extreme cases, some load management programs can even have negative impacts on the distribution and/or transmission system, to the extent that customers increase loads in hours directly preceding or following curtailment events. For this reason, MidAmerican estimates no savings from avoided distribution capacity costs when evaluating load management programs.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

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AFFIDAVIT
OF
JENNIFER L. LONG

STATE OF IOWA)
) ss.
COUNTY OF SCOTT)

I, Jennifer L. Long, being first duly sworn on oath, depose and state that I am the same Jennifer L. Long, identified in the Direct Testimony; that I have caused the Direct Testimony, to be prepared and am familiar with the contents thereof; and that the Direct Testimony, is true and correct to the best of my knowledge and belief as of the date of this Affidavit.

/s/ Jennifer L. Long
Jennifer L. Long

SUBSCRIBED AND SWORN TO before me this 1st day of, February, 2013.

/s/ Debbie A. Sanders
Notary Public in and for the State of Iowa
My commission expires on January 3, 2015