MidAmerican Energy Company
Informational Compliance Filing
With the South Dakota Public Utilities Board as required by
18 CFR 292.302

June 25, 2010

18 CRF 292.302 (b) (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demands of 1,000 megawatts or more. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next five years.

Avoided energy costs for various levels of purchase from qualifying facilities based on MidAmerican's generating costs were estimated using a chronological Monte Carlo simulation production costing model, PROMOD IV. Tables of the resulting avoided energy costs by block for the 0 megawatt level through the 200 megawatt level for 2010 through 2015 are shown on Exhibit A, attached hereto and made a part hereof. The avoided energy costs for zero megawatts are the hourly marginal costs calculated by PROMOD IV.

Five levels of purchases were evaluated: 0 megawatts, 50 megawatts, 100 megawatts, 150 megawatts and 200 megawatts. Avoided energy costs for other levels of purchases were calculated using linear interpolation between those values.

MidAmerican's costs were based on current and committed generating units and forecasts of fuel and variable operation and maintenance costs through 2015. Avoided energy costs were calculated as the difference in energy costs between the specified level of purchase and no purchase.

The avoided energy cost calculations were made for the summer and winter seasons for each year. The summer season is June through September, with all other months in each year in the winter season. The on-peak periods are weekdays from hour ending 7:00 A.M. to 10:00 P.M. All other hours are off-peak.

The forecast firm peak demand and system net requirements for regulated native load customers used in the calculation of avoided energy costs are shown in the following table.

Year	Firm Summer Peak (MW)	Firm Winter Peak (MW)	System Net Requirements (MWh)
2010	4,156	2,996	22,270,800
2011	4,215	3,036	22,877,700
2012	4,260	3,070	23,251,200
2013	4,286	3,088	23,588,000
2014	4,328	3,117	23,905,400
2015	4,373	3,147	24,200,500

Purchases of firm capacity and energy during the six-year period from 2010 through 2015 are a result of a power purchase contract from the output of a 112.5 MW wind farm and are as follows:

Year	July Accredited (MW)	Annual Energy (MWh)
2010	10	266,370
2011	10	267,660
2012	10	271,200
2013	10	269,580
2014	10	267,050
2015	10	265,940

MidAmerican is not forecasting any new unit capacity additions nor any unit generation retirements in the 2010-2015 energy projection timeframe. MidAmerican continues to actively pursue additional wind projects and depending upon market conditions could add as much as 1,001 MW by 2012 or no additional wind generation, although no new wind projects, other than those presently in-service, were included in the 2010-2015 avoided energy cost forecast.

18 CFR 292.302 (b)(3) The estimated capacity costs at completion of the planned capacity additions and planning capacity from purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

MidAmerican continually reviews its capacity needs. This review includes the projecting of forecast load growth, forecast demand side management programs, renewable capacity availability, new regional capacity additions and FERC orders relative to RTO formation, transmission ownership and economic costs.

MidAmerican has used the economic carrying charges on a new combustion turbine to calculate the avoidable capacity cost. Using this methodology, the annual cost in 2010 is $73.06/kW. The installed cost of this unit is estimated to be $786.52/ kW in 2010 dollars. This cost is based on a combination of cost data from the EPRI TAG (Technical Assessment Guide) and assessment of the current combustion turbine market and construction costs.

The following parameters were used to calculate the economic carrying charges and annual revenue requirements for a new 160 MW combustion turbine (summer rating): a weighted-average capital cost of 9.50%; after tax discount rate of 8.05%; 15 year tax life; tax-depreciation basis of 100%; book life of 40 years; and fixed operation and maintenance cost of $7.87/kW/year in 2010 escalating at 2.25% per year. The present value of revenue requirements for the new combustion turbine is estimated to be $1,212.00/kW installed.

Due to additional capacity currently available in the region, the market value of capacity in MidAmerican's service area is approximately $15.00/kW for the entire summer season, which is lower than the equivalent cost of a new combustion turbine. It is expected that the market value of capacity will continue at this or slightly higher levels over the next several years. MidAmerican estimates that the market value of capacity in the 2012-2015 timeframe will be approximately 20% of the annual economic carrying charges for a new combustion turbine unit. As load growth in the region increases and the construction of additional generating capacity is required, the avoidable capacity cost is estimated to approach the cost of a new combustion turbine peaking unit by 2020.

The avoidable new generation capacity costs are as follows.

Year	Avoidable New Generating Capacity Costs ($/kW/yr.)
2010	$ 15.00
2011	$ 15.00
2012	$ 15.28
2013	$ 15.62
2014	$ 15.97
2015	$ 16.33