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

June 30, 2014

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 2014 through 2019 are shown on Exhibit A, attached hereto and made a part hereof.

Five levels of purchases were evaluated: 0 megawatts, 50 megawatts, 100 megawatts, 150 megawatts and 200 megawatts. The avoided energy costs for zero megawatts are the hourly marginal costs calculated by PROMOD IV. Avoided energy costs for 50 MW through 200 MW were calculated as the difference in energy costs between the specified level of purchase and no purchase. 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 2019.

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)
2014	4,575	3,737	24,303,100
2015	4,704	3,838	25,131,600
2016	4,754	3,877	25,534,300
2017	4,798	3,912	25,771,300
2018	4,852	3,954	26,001,300
2019	4,906	3,996	26,226,700

Purchases of firm capacity and energy during the six-year period from 2014 through 2019 are a result of a power purchase contract from the output of a 112.5 MW (nameplate rating) wind farm and are as follows:

Year	July Accredited (MW)	Annual Energy (MWh)
2014	11	240,400
2015	11	240,700
2016	11	242,600
2017	11	240,700
2018	11	240,600
2019	11	180,600

MidAmerican has and is currently constructing and expected to put into service in 2014 (549 MW nameplate capability) and an additional 502 MW in December of 2015. Five new wind sites are being developed; Vienna II 45 MW in-service December 2013; Wellsburg 140 MW with a projected in-service date of August 2014; Macksburg 113 MW with a projected in-service date of October 2014; Lundgren 251 MW with a projected in-service date of November 2014; and Highland 502 MW with a projected in-service date of December 2015.. In addition, MidAmerican expects to retire 520 MW of coal generating capability in April 2015 (WSEC 1, WSEC 2, Neal 1 and Neal 2). These additions and retirements were included in the 2014-2019 avoided energy cost forecast.

18 CFR 292.302 (b)(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years.

Year	Coal Unit Capacity Additions (MW)	Natural Gas Fired Unit Capacity Additions (MW)	Wind Project Capacity Additions (MW)	Coal Unit Capacity Retirements (MW)
2014	4.5	-	-	3.5
2015	21.4	-	-	520.1
2016	-	-	-	-
2017	-	-	-	-
2018	-	14.5	-	-
2019	-	14.5	115.3	-
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-

- MW Capacity Ratings are MISO ICAP Ratings. Capacity is reflected in the calendar year of the first summer after the change occurs and reflects the value of firm transmission service MEC is expected to receive.
- Projection 2014-2023 MEC Financial Plan Approved November 2013.
- There are no new units planned other than the Wind Projects in 2014 and 2015.
- 2019 Wind Capacity assumes a MISO Applied Capacity Rating of 13.3%.
- The additions shown in 2014-2019 represent turbine upgrades to existing generating units, net of environmental compliance excluding the new wind facilities.

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 forecast of load growth, demand side management programs, renewable capacity availability, a review of new regional capacity additions and Federal Energy Regulatory Commission (FERC) orders including those relative to transmission ownership and economic costs.

MidAmerican has used the economic carrying charges on a new combustion turbine to calculate its long-term avoidable capacity cost. Using this methodology, the annual cost in 2014 is $85.83/kW. The installed cost of the combustion turbine unit with a summer capacity of 178 MW (210 MW nominal capacity rating) is $867/kW based on the summer capacity rating and expressed in 2014 dollars. The determination by the Midcontinent

Independent System Operator, Inc. (MISO) in its annual calculation of the Cost of New Entry (CONE) filed with the Federal Energy Regulatory Commission (FERC) is the basis for the avoided cost calculation.[1]

The calculation of economic carrying charges and annual revenue requirements is based upon a weighted-average capital cost of 7.5%, an after tax discount rate of 6.47%, a 15 year tax life, tax-depreciation basis of 100%, book life of 30 years, and fixed operation and maintenance cost of $8.58/kW/year in 2014 escalating at 2.0% per year. The present value of revenue requirements for the new combustion turbine is estimated to be $1,479.74/kW installed in 2014.

The capacity prices in 2014 and 2015 are based on opportunity market prices within MISO. The Independent Market Monitor (IMM) for MISO calculated those prices for the MISO 2014-2015 Planning Resource Auction based on PJM Interconnection, L.L.C.'s Reliability Pricing Model (RPM), a capacity-market model designed to create long-term pricing signals based on making capacity commitments three years ahead. The 2014-2015 Base Residual Auction (BRA) cleared 147,974.4 MW of capacity at the RTO Resource Clearing Price of $125.99/MW-day. Based on a MW-weighted average of the BRA ($125.99/MW-day) and three incremental auctions of $0.03/MW-day, $25.00/MW-day and $25.51/MW-day, an opportunity cost of $25.06/MW-day and an adjustment downward to reflect a delivery cost from MISO to PJM, MidAmerican has assigned a market value of capacity of $52.15/kW in 2014. Using the 2014-2015 IMM methodology, the rate for 2015 was determined to be $56.58/kW.

The avoidable new generation capacity costs are as follows.

Year	Avoidable New Generating Capacity Costs ($/kW/yr.)
2014	$ 52.15
2015	$ 56.58
2016	$ 89.30
2017	$ 91.09
2018	$ 92.91
2019	$ 94.77

[1] The capacity price for a combustion turbine is based on MISO's CONE for the Local Resource Zone 3 (LRZ 3) in the September 3, 2013 letter to the FERC regarding "Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation; FERC Docket No. ER13-2310-000." The capacity price for LRZ 3 is $704.50 in 2014 dollars. That capacity price was converted to a summer-based capacity price.