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

## June 30, 2016

Every two years, MidAmerican Energy Company (MidAmerican) is required to file the following information with the South Dakota Public Utilities Commission regarding the calculation of MidAmerican's avoided cost.

**18 CFR 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 were calculated using MidAmerican's generating costs from MidAmerican generating units dispatched against a market price simulating the Midcontinent Independent System Operator, Inc. (MISO) market, using a production costing model, PROMOD IV. The MidAmerican generating units selected to run in the particular hour are summarized by fuel type. The energy production and costs reflect the allocation of actual costs of MidAmerican's generation assets that are used to serve MidAmerican's Iowa/South Dakota customers. Energy and costs from WSEC 4, GDMEC and the Wind projects (New Generation) are not allocated to the Illinois retail jurisdiction.[1]

While the market dispatch methodology is identical to the methodology used in the prior avoided cost rate filing, the data used in the present filing includes the allocation of the New Generation production costs to only the Iowa and South Dakota retail jurisdictions. The data used in the market dispatch allocates the remainder of the generation to all three jurisdictions. The New Generation and generation allocated to Iowa and South Dakota are used to develop the avoided energy costs.

In MidAmerican's 2014 filing, the data used in market dispatch methodology was based on allocating all generation costs to MidAmerican's entire service territory. In 2016, the Illinois jurisdiction began procuring an incremental portion of its energy production from the Illinois Power Agency. To account for this change, the new avoided energy costs include production costs to serve the Iowa and South Dakota retail load based on the Iowa and South Dakota jurisdictional allocated production costs. The Illinois jurisdictional costs

1. *See* Docket Nos. SPU-05-9, SPU-05-12, citing RPU-01-9, RPU-02-10, RPU-03-1, and RPU-04-3. *See also* RPU-05-4; RPU-07-2; RPU-08-2; RPU-08-4; RPU-2009-0003; RPU-2013-0003; RPU-2014-0002; and RPU-2015-0002.

for energy production costs and the costs from procuring energy from the Illinois Power Agency were excluded from the Iowa and South Dakota production data. Therefore, the energy production data used in this avoided energy cost filing reflects the actual energy production allocated to serve the Iowa and South Dakota retail jurisdiction and excludes the Illinois allocated energy production costs.

For the Iowa and South Dakota jurisdictions, the fuel types from all MidAmerican generation (discussed in Paragraph 2 above) is allocated from lowest incremental production cost to highest incremental production cost (wind, nuclear, coal and natural gas) to meet MidAmerican's Iowa and South Dakota retail energy requirement in each hour. In the event the hourly generation does not meet the retail energy requirement, a net market purchase is calculated and priced. The resulting average annual production costs of the hourly fuel type cost expected to meet the retail energy need is the basis for the avoided energy cost rates. Tables of the resulting avoided energy costs by block for the 0 megawatt level through the 200 megawatt level for 2016 through 2021 are shown on the attached Exhibit A.

Exhibit A reflects the five levels of purchases evaluated; 0 megawatts, 50 megawatts, 100 megawatts, 150 megawatts and 200 megawatts. Avoided energy costs for 50 MW through 200 MW levels were calculated as a decrement to the hourly retail load requirement. Avoided energy costs for levels of purchases below 50 MW were calculated using linear interpolation between the 0 MW and 50 MW values.

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 Total Company Peak (MW) | Firm Summer Iowa/South Dakota Peak (MW) | System Net Total Company Requirements (MWh) | Iowa/South Dakota Net System Requirements (MWh) |
|---|---|---|---|---|
| 2016 | 4,939 | 4,475 | 25,349,700 | 23,224,500 |
| 2017 | 5,081 | 4,614 | 26,320,600 | 24,186,600 |
| 2018 | 5,133 | 4,663 | 26,840,500 | 24,699,600 |
| 2019 | 5,203 | 4,730 | 27,261,300 | 25,110,300 |
| 2020 | 5,257 | 4,781 | 27,693,100 | 25,533,400 |
| 2021 | 5,308 | 4,829 | 27,913,200 | 25,741,800 |

Purchases of firm capacity and energy during the six-year period from 2016 through 2021 are a result of a power purchase contract for the output of a 112.5 MW (nameplate) wind farm expiring November 2019 and two behind the MISO meter purchase contracts; a 20 MW (nameplate) wind farm and a 6 MW (nameplate) methane landfill producer.

| Year | Summer Accredited (MW) | Total Company Annual Energy (MWh) | Iowa/South Dakota Annual Energy Share (MWh) |
|---|---|---|---|
| 2016 | 20 | 292,100 | 279,800 |
| 2017 | 20 | 297,300 | 284,900 |
| 2018 | 20 | 296,800 | 284,400 |
| 2019 | 9 | 281,800 | 269,400 |
| 2020 | 9 | 114,700 | 102,300 |
| 2021 | 9 | 114,100 | 101,700 |

MidAmerican is currently constructing and expects to put into service in 2016, 550 MW of wind generation at two wind sites; Ida Grove 300 MW in-service December 2016 and O'Brien 250 MW in-service December 2016. All MW listed in this paragraph for wind sites are nameplate capacity. MidAmerican retired 390 MW of coal-fired generating capability in April 2016 (Neal 1 and Neal 2). These additions and retirements were included in the 2016-2021 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 (Wind X) (MW) | Coal Unit Capacity Retirements (Neal 1 and 2) (MW) |
|---|---|---|---|---|
| **2016** | - | - | 550 | 390 |
| **2017** | - | - | - | - |
| **2018** | - | - | - | - |
| **2019** | - | - | - | - |
| **2020** | - | - | - | - |
| **2021** | - | - | - | - |
| **2022** | - | - | - | - |
| **2023** | - | - | - | - |
| **2024** | - | - | - | - |
| **2025** | - | - | - | - |

- There are no new units planned other than the Wind Projects.

- The amounts shown under the Wind Project Capacity Additions represent installed nameplate capacity values.
- MidAmerican filed with the Iowa Utilities Board for approval of the proposed 2000 MW Wind XI project in April 2016 (RPU-2016-0001), for which the nameplate capacity is not reflected in this table.

**<u>18 CFR 292.302 (b)(3)</u>. 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 2016 is $85.54/kW. The installed cost of the combustion turbine unit with a net summer capacity of 172 MW (210 MW nominal capacity rating) is $910/kW based on the summer capacity rating and expressed in 2016 dollars. The determination by MISO in its annual calculation of the Cost of New Entry (CONE) filed with FERC is the basis for the avoided cost calculation.[2]

The calculation of economic carrying charges and annual revenue requirements is based upon a weighted-average capital cost of 7.13%, an after tax discount rate of 6.27%, a 15 year tax life, tax-depreciation basis of 100%, book life of 30 years and fixed operation and maintenance costs of $8.95/kW/year in 2015 escalating at 2.25% per year. The present value of annual expenses for the new combustion turbine is estimated to be $1,549/kW installed in 2016.

Near-term capacity prices are based on opportunity pricing from the MISO capacity auction, followed by a two year bridging period, and then based upon the economic carrying charge of a new simple cycle combustion turbine. The MISO capacity auction cleared at $72/MW-day for Zone 3, or $26.28/kW-year for the June 2016 through May 2017 annual auction (the 2016/17 "Planning Year"). The economic carrying charge-based pricing begins with a price of $92.30/kW-year for the 2019/20 Planning Year, and price of $94.38/kW-year for the 2020/21 Planning Year (2.25% escalation). The two year bridging period results in a price of $48.68/kW-year for the 2017/18 Planning Year, and a price of

2. The capacity price for a combustion turbine is based on MISO's CONE for the Local Resource Zone 3 (LRZ 3) in the September 16, 2015 letter to FERC, Filing of MISO regarding LRZ CONE Calculation; FERC Docket No. ER15-2660. The capacity price for LRZ 3 is $710 in 2015 dollars. That capacity price was converted to a summer-based capacity price.

$70.49/kW-year for the 2018/19 Planning Year. The table below converts these values to calendar year prices. In MidAmerican's last filing of avoided costs, the near-term opportunity cost pricing used MISO's Initial Reference Level as determined by the Independent Market Monitor. The change for this filing is the result of a FERC order on December 31, 2015, where FERC directed MISO to revise its tariff to no longer utilize PJM auction prices as the key component to MISO's determination of the Initial Reference Level.[3]

The avoidable new generation capacity costs are as follows.

| Year | Avoidable New Generating Capacity Costs ($/kW/yr.) |
|---|---|
| 2016 | 26.87 |
| 2017 | 35.96 |
| 2018 | 57.77 |
| 2019 | 91.44 |
| 2020 | 92.50 |
| 2021 | 95.60 |

[3] In recent prior filings of avoided capacity costs, MidAmerican applied opportunity cost pricing based upon PJM capacity auction pricing, which was consistent with the MISO Market Monitor's Initial Reference Level determination for the MISO capacity auction. On December 31, 2015, an order was issued in FERC Docket Nos. EL15-70, EL15-71, EL15-72, and EL15-82, which required MISO to set its Initial Reference Level to $0/MW-day. Market monitoring provisions set the conduct thresholds at 10% of the Cost of New Entry (CONE) for Zone 3, or $25.52-MW-day ($9.31/kW-year). *See* Slide 7: MISO 2016/2017 Planning Resource Auction Results