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

June 30, 2020

<u>18 CFR 292.302(b)(1)</u>. 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 costs of MidAmerican's generation assets that are used to serve MidAmerican's Iowa/South Dakota customers. Energy and costs from Walter Scott Energy Center Unit 4, Greater Des Moines Energy Center and the Wind projects (herein after collectively referred to as "New Generation") are not allocated to the Illinois retail jurisdiction. The fuel types are 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 2020 through 2025 are shown on the attached Exhibit A.

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.

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)
2020	4,781	4,339	27,299,900	24,777,400
2021	4,840	4,393	27,559,400	25,012,900
2022	4,903	4,450	27,823,400	25,252,600
2023	4,965	4,506	28,092,100	25,496,400
2024	5,025	4,561	28,365,000	25,744,100
2025	5,084	4,614	28,644,700	25,997,900

Purchases of firm capacity and energy during the six-year period from 2020 through 2025 are a result of a power purchase contract for the output of a 112.5 MW (nameplate) wind farm 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)
2020	21.9	308,900	298,100
2021	21.9	308,500	297,700
2022	21.9	308,600	297,900
2023	21.9	308,700	298,000
2024	21.9	309,300	298,500
2025	21.9	308,800	298,000

Additions and retirements were phased in to the 2020-2025 avoided energy cost forecast based upon planned in-service and retirement dates which included 706 MW of new wind generation, acquisition of an existing 80 MW wind farm, planned solar of 10 MW, and retirement of an existing 110 MW natural gas-fired generator. New wind resource sites included Palo Alto II (Wind XII) 90 MW in-service November 2020, Southern Hills (Wind XII) 131 MW in-service November 2020, Diamond Trail (Wind XII) 169 MW in-service October 2020, Southern Hills II 120 MW in-service December 2020, Diamond Trail II 84 MW in-service November 2020 and Contrail 112 MW in-service December 2020. The existing wind site acquisition in April 2020 is the 80 MW Pocahontas Prairie project, and the solar projects include 3 MW completed in November 2020 and a planned 7 MW to be completed in November 2021. The 110 MW gas-fired Riverside 5 generating facility is planned for retirement in May of 2021.

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/Solar Project Capacity Additions (Wind XII & Others) (MW)	Natural Gas Fired Unit Capacity Retirements (MW)
2020	-	-	796.0	-
2021	-	-	-	110.0
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-

MidAmerican filed with the Iowa Utilities Board for approval of the proposed 591 MW Wind XII project in May 2018 (RPU-2018-0003) and was approved by the Board in December 2018.

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 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 2020 is $79.06/kW. The installed cost of the combustion turbine unit with a net summer capacity of 204 MW (237 MW nominal capacity rating) is $881/kW based on the summer capacity rating and expressed in 2020 dollars. The determination by the MISO in its annual calculation of the Cost of New Entry (CONE) filed with the 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 7.00%, an after tax discount rate of 6.43%, a 15 year tax life, tax-depreciation basis of 100%, book life of 30 years and fixed operation and maintenance costs of $7.00/kW/year in 2019 escalating at 2.25% per year. The present value of annual expenses for the new combustion turbine is estimated to be $1,408/kW installed in 2020.

Near-term capacity prices are based on opportunity pricing from the MISO capacity auction, followed by a three year bridging period, and then based upon the economic carrying charge of a new simple cycle combustion turbine. Near term opportunity pricing is the higher of the MISO capacity auction clearing price of $5.00/MW-day for Zone 3, or $1.83/kW-year, or 10% of the MISO CONE of $91.330/kW-year; both for the June 2020 through May 2021 annual auction (the 2020/21 "Planning Year"). A price of $9.34 for the 2021/2022 Planning Year was calculated by escalating the 2020/2021 MISO CONE of $9.13/kW-year by 2.25%. The economic carrying charge-based pricing begins with a price of $87.23/kW-year for the 2024/25 Planning Year and price of $89.19/kW-year for the 2025/26 Planning Year (2.25% escalation). The three year bridging period results in a price of $35.30/kW-year for the 2022/23 Planning Year, a price of $61.27/kW-year for the 2023/24 Planning Year and a price of $87.23/kW-year for the 2024/25 Planning Year. The table below converts these values to calendar year prices.

The avoidable new generation capacity costs are as follows.

Year	Avoidable New Generating Capacity Costs ($/kW/yr.)
2020	$ 9.13
2021	$ 9.25
2022	$ 24.48
2023	$ 50.45
2024	$ 86.42
2025	$ 88.37

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 10, 2019 letter to the FERC, Filing of MISO regarding LRZ CONE Calculation; FERC Docket No. ER19-2781-000. The capacity price for LRZ 3 is $730.50 in 2020 dollars. That capacity price was converted to a summer-based capacity price.