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

June 25, 2024

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, Aurora. 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 MidAmerican's wind and solar projects ("New Generation") are not allocated to the Illinois retail jurisdiction.[1] The fuel types are allocated from lowest incremental production cost to highest incremental production cost (renewable, 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 2024 through 2029 are shown on the attached Exhibit A.

The market dispatch methodology is the same 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

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.

used to develop the avoided energy costs.

Exhibit A reflects the nine levels of purchases evaluated: 0 megawatts, 10 megawatts, 20 megawatts, 30 megawatts, 40 megawatts, 50 megawatts, 100 megawatts, 150 megawatts and 200 megawatts. Avoided energy costs for 0 MW through 200 MW levels were calculated as a decrement to the hourly retail load requirement.

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)
2024	[redacted]			
2025				
2026				
2027				
2028				
2029				

Purchases of firm capacity and energy during the six-year period from 2024 through 2029 are a result of a power purchase contract for the output of a 108 MW (nameplate) wind farm which expires in 2027 and three behind the MISO meter purchase contracts; a 20 MW (nameplate) wind farm which expires in 2040, a 6 MW (nameplate) methane landfill producer which expires in 2026 and a 1 MW (nameplate) waste water producer which expires in 2028.

Year	Total Company Summer Accredited (MW)	Iowa/South Dakota Summer Accredited (MW)	Total Company Annual Energy (MWh)	Iowa/South Dakota Annual Energy Share (MWh)
2024	[redacted]			
2025				
2026				
2027				
2028				
2029				

Additions and retirements that serve Iowa/South Dakota regulated load were included in the 2024-2029 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.

MidAmerican filed with the Iowa Utilities Board for approval of the proposed 2,092 MW Wind PRIME project in January 2022 (RPU-2022-0001) and was approved on December 14, 2023.

Year	Coal Unit Capacity Additions (MW)	Natural Gas Fired Unit Capacity Additions (MW)	Wind/Solar Project Capacity Additions (Wind PRIME) (MW)	Natural Gas Fired Unit Capacity Retirements (MW)
2024	-	-	625.7	-
2025	-	-	642.1	-
2026	-	-	540.4	-
2027	-	-	283.8	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-

<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, MISO resource adequacy requirements, and Federal Energy Regulatory Commission ("FERC") orders including those relative to transmission ownership and economic costs. MISO continues to utilize CONE as an auction parameter with its recent proposed reforms that could include a reliability-based demand curve and direct loss of load capacity accreditation and planning reserve margin requirements. MISO's CONE values for Planning Year 2024/2025 are up significantly on a year ago, primarily due to significant increases in base capital project costs and weighted average cost of capital.

MidAmerican used the economic carrying charges for a new combustion turbine to calculate its long-term avoidable capacity cost. Using this methodology, the annual cost in 2024 is $103.62/kW. The installed cost of the combustion turbine unit with a net summer capacity of 204 MW (237 MW nominal capacity rating) is $1,128/kW based on the summer capacity rating and expressed in 2024 dollars. The determination by MISO in its annual calculation of the Cost of New Entry (CONE) filed with the 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 7.05%, an after-tax discount rate of 6.51%, a 15-year tax life, tax-depreciation basis of 100%, book life of 30 years and fixed operation and maintenance costs of $10.15/kW-year expressed in 2024 dollars. The present value of annual expenses for the new combustion turbine is estimated to be $1,829/kW installed in 2024.

---

2 The capacity price for a combustion turbine is based on MISO's CONE for the Local Resource Zone 3 (LRZ 3) in the October 5, 2023 letter to the FERC, Filing of MISO regarding LRZ CONE Calculation; FERC Docket No. ER24—37-000. The project cost for LRZ 3 is $914.50 per kW in 2024 dollars. That project cost was converted to a summer-based cost based on the summer rating of an advanced combustion turbine.

Economic carrying charges for the new combustion turbine are calculated by the formula:

$$ECC_t = k\ x\ (r - i)\ x\ \frac{(1 + r)^{(n-1)}}{(1 + r)^n - (1 + i)^n}\ x\ (1 + i)^{(t-1)}$$

Where:
ECC_t = Economic carrying charge in year "t"
k = Present value rate of revenue requirement
n = Expected life of investment
i = Inflation rate
r = Discount rate

Near-term capacity prices are based on the offer cap of 10% of CONE for the MISO Planning Resource Auction, followed by a three-year bridging period (years 2025 through 2027), and then based upon the economic carrying charge of a new simple cycle combustion turbine as calculated by MidAmerican. 10% of CONE for Zone 3 is equal to $11.76/kW-year for June 2024 through May 2025 (the 2024/25 “Planning Year”). A price of $12.02/kW-year for the 2025/2026 Planning Year was calculated by escalating the 2024/2025 MISO clearing price by 2.25%. MidAmerican’s economic carrying charge-based pricing begins with a price of $114.32/kW-year for the 2028/29 Planning Year and a price of $116.89/kW-year for the 2029/30 Planning Year (2.25% escalation). The three-year bridging period results in a price of $46.12/kW-year for the 2026/27 Planning Year, a price of $80.22/kW-year for the 2027/28 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-year)
2024	$11.76
2025	$11.91
2026	$31.92
2027	$66.01
2028	$113.26
2029	$115.81