STATE OF IOWA
DEPARTMENT OF COMMERVE
IOWA UTILITIES BOARD

IN RE: **APPLICATION OF MIDAMERICAN ENERGY COMPANY FOR DETERMINING OF RATEMAKING PRINCIPLES**	**DOCKET NO. RPU-2018-0003**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

SIERRA CLUB

PUBLIC VERSION

Resource Insight, Inc.

AUGUST 3, 2018

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Incorporated, 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight since 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical plants entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included many reviews of the economics of power plants, utility planning, marginal costs, and related issues.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the scope of your testimony?

A: I address one of the questions that the Board has instructed MidAmerican Energy Company (MidAmerican or MEC) to address in any request for advanced ratemaking principles, regarding whether MidAmerican's existing generation continue to be used and useful:

> Wind generation will reduce the production needed from generating units that are already included in MidAmerican's rates. Will all of the existing generation currently in MidAmerican's rates continue to be used and useful?[1]

In particular, I examine whether the market value of MidAmerican's existing coal-fired units exceed the costs of continuing to run them, in the

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[1] *In Re: MidAmerican Energy*, Request for Approval of Ratemaking Principles, Order Requiring Additional Information, Docket No. RPU-2014-0002 (Nov. 14, 2014).

present environment of low gas costs and the widespread installation of low-cost (and declining-cost) wind and solar resources.

My testimony relies on numerous MidAmerican documents and discovery responses, including the testimony of MidAmerican witnesses Adam L. Wright, Neil D. Hammer and Thomas B. Specketer.

Q: Why focus your testimony on the Company's coal units?

A: Keeping the existing coal units in service is expensive, compared to the costs of the gas-fired units. Economic operation of coal units is heavily dependent on having a large number of hours in which market prices are higher than the costs of fuel and other operating costs for starting the units and generating electricity. Since each coal unit is much less nimble than most gas-fired or hydro plants, those profitable hours also need to be predictable days in advance and must occur in clusters long enough to pay for the costs of cycling the unit up and down. The addition of large amounts of wind regionally has reduced the profitability of coal plants more than most other types of generation.

Q: What information did MidAmerican provide in its Application in response to the Board's instruction to explain whether its existing generation remains used and useful?

A: MidAmerican Witness Hammer included the following in his testimony, at 16:

> Q. Wind generation will reduce the percentage of energy production needed from other MidAmerican resources. Will MidAmerican's existing generation continue to be used and useful?
>
> A. Yes. As shown in the load and capability forecast, MidAmerican's existing generation remains a key part of meeting MidAmerican's resource adequacy needs so that grid reliability is maintained.

Q: Does Mr. Hammer's response demonstrate that the existing capacity is used and useful?

A: No. As I discuss in greater detail below, MidAmerican's response does not begin to answer the question requested by the Board.

Q: Which coal capacity does MidAmerican own?

A: MidAmerican owns parts of six coal units, as summarized in Table 1.

Table 1: MidAmerican Coal Plants

Plant	Unit	Year Installed[a]	Summer Capacity (MW)[b]	MEC Share Percent[c]	MEC Share MW[d]	MEC 2017 Net GWh Generation[e]
Louisa	1	1983	743.9	88.0%	655	3,521
Ottumwa	1	1981	718.2	52.0%	380	4,019
George Neal North	3	1975	510.0	72.0%	369	2,156
George Neal South	4	1979	644.0	40.6%	269	2,442
Walter Scott Jr.	3	1978	703.7	79.1%	513	4,691
Walter Scott Jr.	4	2007	813.6	59.7%	534	3,872

Data sources:
[a] 2017 FERC Form 1, p. 402
[b] 2017ER EIA 860
[c] 2017ER EIA 860, Owner file
[d] Hammer Testimony, Table 2, at 11; net of purchases and sales of Scott capacity
[e] EIA 923, Generator file

Interstate Power and Light (IP&L) operates Ottumwa; the other coal units are operated by MidAmerican. Other than the shares owned by MidAmerican, IP&L (4% of Louisa, 28% of Neal 3, 25.7% of Neal 4 and 48% of Ottumwa) and NorthWestern Corporation (8.68% of Neal 4), the remaining portions of the units are owned by various municipal and cooperative utilities, which do not file the same amount of public cost data as do the investor-owned utilities.

Q: Does it appear that continued operation of all the MidAmerican coal entitlements would be advantageous for ratepayers?

A: No. The costs of fuel, operating and maintenance (O&M), overheads, and ongoing capital additions for most of the units, and particularly Ottumwa and

Neal 3, appear to exceed the market value of their output. Once MidAmerican has committed to operate a unit for a year (or other lengthy period), it makes sense to run the unit in each hour in which the market energy price exceeds the unit's fuel and variable O&M. Looking at only these short-run marginal costs, the coal plants are all economic to run in some hours, as I detail in Section IV. But the decision to keep a unit online for one or more years constitutes a commitment to pay the fixed O&M, overheads, and capital additions needed to keep it running.

Replacement resources, especially wind, are less expensive than continuing to run the coal plants.

Q: How are the MidAmerican units dispatched?

A: The MidAmerican units sell all their output to the MISO market and purchase all energy required for load from MISO. (DR OCA-15b) Thus, the value of the power plants and the costs of serving customers are distinct.

Q: How does MidAmerican take economics into account in deciding whether to retire its fossil plants?

A: MidAmerican says that it takes economics into account when it actually addresses the retirement decision:

> With any asset, MidAmerican considers whether it is economical to continue the operation of the asset and the value the asset has for customers. This includes a consideration of forecasted revenue, fuel prices, operation and maintenance costs, load growth and associated energy and summer peaking, and costs of alternative options. (EI-11)

Despite this assertion, MidAmerican does not appear to have conducted any analysis of the economics of continued operation of its coal units. Specifically, MidAmerican says that it has not forecast any plant retirements (DR 2-SC-2, DR 1-SC-10, DR 2-SC-6b). Further, when asked to provide estimated retirements dates and any completed cost analysis of continued plant operation, MidAmerican objected claiming the request "irrelevant and unlikely to lead to the discovery of relevant evidence." (DR 2-SC-6c, DR 2-SC-8).

Q: If the units are uneconomic, why are they still running?

A: There are three ways in which MidAmerican may have kept the plants running at relatively high capacity factors. First, rather than bidding its coal units into the market as resources to be dispatched economically, MidAmerican may have designated various of its coal units as "self-scheduled" or "must-run" units, ensuring that MISO will dispatch them, regardless of cost or price. MidAmerican says that its PROMOD projections assumed that "[redacted]"[2] (DR OCA-15b) The projected capacity factors for these units (and the historical capacity factors for these and other units) may be inflated by operation in hours in which the units are operating uneconomically.[3]

Second, when MidAmerican bids the units into the MISO energy market, it may bid them in at prices below their short-run marginal costs of

[2] It is not clear whether the [redacted] designation in PROMOD, or in actual MISO commitment and scheduling, requires that the unit operate at its minimum stable load, or some higher output level.

[3] When asked for "a detailed explanation of the reasoning" for why "certain generating units would be placed in a particular status during identified portions of the year" and a quantification of "the resulting economic penalty to MidAmerican's retail customers," MidAmerican replied that [redacted] (IBEC-24) If [redacted] is beneficial, [redacted] must come at a cost.

fuel and variable O&M. MidAmerican has not provided its bid prices (DR 2-SC-1)

Third, the coal units incur costs, including fixed O&M and capital additions, that would not be included in the hourly energy market bids, but need to be covered by the profit in the market. If MidAmerican ignores the fixed annual O&M and investment costs, it would find many hours in which the units are worth running, considering only the hourly fuel and variable O&M. A generator can make money in many hours but still lose money over the year.

The first two mechanisms represent situations in which MidAmerican could force the coal units to run when they are not economic sources of energy for the region. Merchant generation owners usually do not engage in that behavior, since they would lose money on every MWh sold. Vertically-integrated utilities, on the other hand, can often count on recovering those losses from their retail (and in some cases, regulated wholesale) customers. I do not fully understand MidAmerican's incentives to run the coal plants uneconomically, but the Company may be motivated by an interest in avoiding scrutiny of the coal plants' economics until more of their costs have been depreciated.

The third mechanism results from the difference between short-run (hourly or daily) costs and annual costs. Even a unit that can dispatch at costs below the market price in every hour (e.g., a hydro or nuclear plant), covering its variable costs by a wide margin, may not cover its fixed O&M, capital additions, and other forward-going costs. Many merchant power plants (including some nuclear plants, which have short-run costs below market energy prices in almost all hours) have retired due to the inability to cover their forward-going costs.[4] Over time, the most expensive plants should be replaced by less-expensive resources. MidAmerican has been adding the less-expensive wind resources, and has retired some 540 MW of coal capacity at five units at Riverside, Neal and Scott in 2013 through 2016. As MidAmerican adds another 2,200 MW of capacity in Wind XI and Wind XII, and as other renewable projects are built in the region, it should be retiring additional expensive coal units.

Since MidAmerican is not subject to market discipline, as it would be if it were a merchant generator, that role falls to the Commission.

Q: Does MidAmerican explain why it designated those units as [redacted]?

A: MidAmerican says that “[redacted].” (IBEC-24) In other words, the units [redacted]. Since both PROMOD and MISO attempt to minimize net costs, it is not clear why MidAmerican would need to [redacted] to minimize costs. MidAmerican suggests that it does not know why Ottumwa is [redacted] (IBEC-24)

[4] In recent news, Interstate Power and Light has bought out of its contract to purchase energy from the Duane Arnold nuclear plant. Faced with the unfavorable economics of operating that unit in the MISO energy market, NextEra has announced that it will retire the plant in 2020, provide 340 MW from repowered wind facilities, and invest another $400 million in new Iowa renewables by 2020 (https://www.prnewswire.com/news-releases/nextera-energy-resources-and-alliant-energy-agree-to-shorten-the-term-of-the-duane-arnold-energy-center-power-purchase-agreement-alliant-energy-customers-to-save-hundreds-of-millions-of-dollars-300687767.html).

A. MidAmerican Generation Objectives

Q: What are MidAmerican's goals for its generation system?

A: As articulated by MidAmerican witnesses Hammer (at 2 and 22) and Wright (at 38), MidAmerican's planning criteria can be stated as:

- Reducing expected costs to ratepayers.
- Reducing exposure to fossil fuel price variability and geo-political uncertainty, increasing resource availability and stability.
- Current and future environmental compatibility and sustainability.
- Promoting system reliability.
- Advancing economic development.
- Promoting flexibility and optionality.
- Increasing diversity of power supply.
- Supporting Iowa's energy policy of being a renewable energy leader.

Q: Is maintaining the entire MidAmerican coal fleet likely to reduce expected costs to ratepayers?

A: No. I address this question in Section IV.

Q: Is maintaining the entire MidAmerican coal fleet likely to reduce exposure to fossil fuel price variability and geo-political uncertainty, or to increase resource availability and stability?

A: No. In Mr. Hammer's assessment, "Coal is…currently hampered by emissions." (Hammer Direct at 36) "Fossil-fueled resources emit carbon dioxide, so policies that would encourage the reduction of carbon emissions improve the economics" of wind and other renewables (ibid at 25).

A large MidAmerican coal unit also has a greater vulnerability as a "target for a terrorist attack. Smaller, dispersed generation resources, such as wind, solar, and combustion turbine peaking units, are less likely to be targets than larger resources that would have a greater impact and have a higher public profile." (Hammer Direct at 32)

Q: Is the MidAmerican coal fleet consistent with current and future environmental compatibility and sustainability?

A: No.

> Coal-fueled units receive the lowest ranking, even assuming the use of modern emissions controls. Coal mining operations, byproduct disposal, and pollutant emissions (i.e., carbon dioxide, sulfur dioxide, oxides of nitrogen, and mercury) limit coal-fueled technologies with respect to the environmental criterion. (Hammer Direct at 26)

In addition, Mr. Hammer is clearly describing coal plants when he expresses concerns about "Uncertainty, such as that surrounding carbon regulation or regulation of the interstate transport of emissions" (Hammer Direct at 32).

Q: Are the coal units a good option for promoting system reliability?

A: No. The existence of the coal units does contribute to some aspects of reliability, but as Mr. Hammer points out "[t]he variability of load and generation requires generation to adjust so that the area control error is maintained within acceptable bounds." (Hammer Direct at 27) As I discuss in Section IV.C, the coal units are not able to respond quickly to changes in load and generation.

Q: Do MidAmerican's coal units promote economic development?

A: No. While the coal plants provide some level of direct and indirect local employment and property taxes, they are not good vehicles for economic development. Four of the coal units appear to increase rates, which will tend to reduce economic activity in MidAmerican's service territory. The coal units also do not provide the broader economic stimulus that renewable resources encourage:

> [R]enewable generation provides the ability to attract sustainability-focused businesses to locate and expand in Iowa. Development of Iowa wind projects has also drawn wind equipment manufacturing to Iowa and facilities in Iowa operated by customers like Apple (facility announced), Facebook, Google, and Microsoft, with all the attendant economic development benefits (e.g., jobs, property taxes, local expenditures). (Hammer Direct at 30–31; see also Fehr Direct at 16–17 and Wright at 11–12)
>
> The potential for work force, ongoing operations and maintenance staff, new customer facilities in the state, and property tax revenues and royalties within the state is greater for generation resources like wind. (Hammer at 30–31)

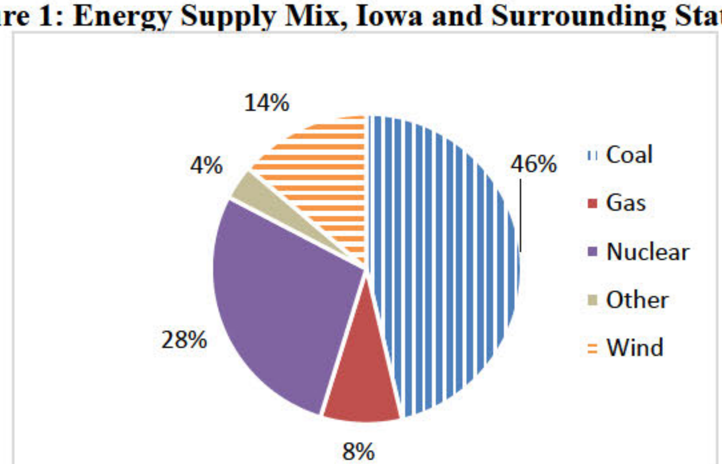
Q: Do MidAmerican's coal units provide the flexibility and optionality that MidAmerican identifies as a goal of its planning process?

A: No. The coal units have limited operational flexibility, as I describe in Section IV.C. Mr. Hammer (Direct at 33) describes ways that a coal-fired facility could be flexibly repurposed "such as fuel switching (e.g., coal to gas, coal to biomass), conversion to other technologies (e.g., conversion of a coal resource to a combined-cycle resource, …)." Note that the potential flexibility of the coal units resides in the feasibility of converting them to other fuels. While those conversions might be attractive for smaller coal units, the MidAmerican units are so large that gas conversion would leave MidAmerican with oversized, operationally inflexible and inefficient gas units.

Q: Do the uneconomic coal units increase the diversity of MidAmerican's power supply?

A: Not really. In 2017, coal was the dominant energy source in the region that Mr. Hammer identified as relevant to supply diversity in his Table 4. That table provided the capacity of generation sources, which overstates the contribution of some fuel types (such as gas) and understates others (such as nuclear. Figure 1 shows the share of electric energy generation by fuel for the eight-state region Mr. Hammer highlighted. For simplicity, I combined six of Mr. Hammer's categories into "other," which is still a small fraction of energy supply.

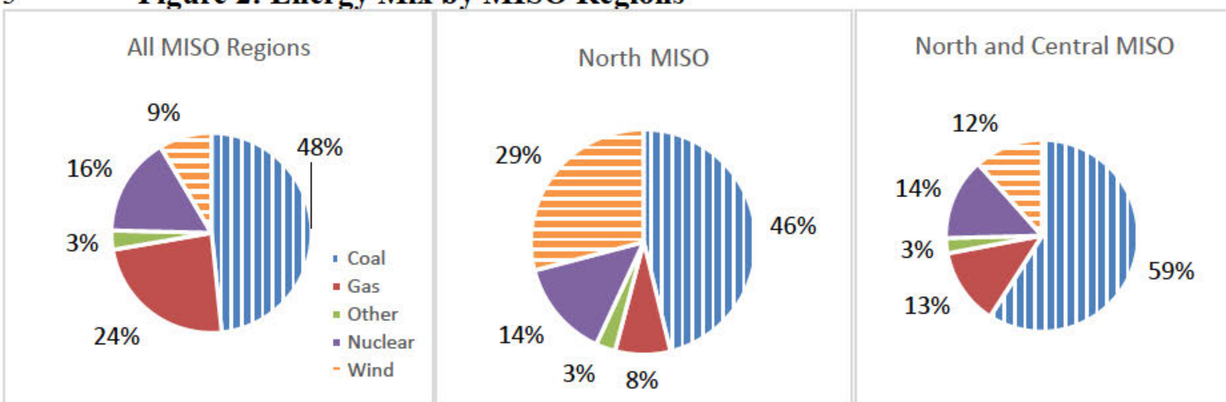
Figure 1: Energy Supply Mix, Iowa and Surrounding States, 2017



Coal and nuclear provided a larger share of energy than capacity, while gas provided a smaller share of energy than capacity. Coal produced nearly half the total energy, and more than three times as much energy as wind, so maintaining coal capacity decreases diversity.

Figure 2 shows the energy splits for all of MISO, the MISO North region (which includes Iowa), and the combined MISO North and East regions. I included the latter because Iowa is more closely linked (at least in the capacity markets) to most of the Eastern zones than to Minnesota, which dominates the North region.

Figure 2: Energy Mix by MISO Regions



In all three MISO groupings, coal is the dominant fuel. Retaining coal units will not increase diversity.

Q: Do the coal plants support Iowa's energy policy of being a renewable energy leader?

A: No. MidAmerican is attempting to serve its customers with 100% renewable energy.

> Wind XII would be the culmination of the renewable vision identified in Wind XI. If the Board approves Wind XII, MidAmerican will be the first investor-owned utility in the country that can claim it is providing its customers with 100% renewable energy on an annual basis. This would be an incredible, one-of-a-kind accomplishment of which the Board, policymakers, and customers should be extremely proud.
>
> Wind XII is important for other reasons. MidAmerican continues to see an energy industry undergoing a significant transformation, as customers continue to demand that more of their energy come from renewable sources. MidAmerican assumed a leadership role in this transformation with the development of approximately 6,050 MW of wind generation when Wind XI is completed. MidAmerican recently requested in Docket No. SPU-2018-0004 that the Board verify that renewable generation supplied 50.8% of MidAmerican's Iowa retail customers' energy needs in 2017. Continued construction of Wind XI and the potential for Wind XII is expected to move that figure over the 100% mark in 2021. This will, for a period of time, make MidAmerican's 100% renewable vision

> a reality. As the testimony of MidAmerican witness Hammer identifies, MidAmerican's 100% renewable vision, including Wind XII, not only benefits the environment and Iowa's economy, but also provides a long-term supply of energy that has low marginal costs and meets a number of customer needs. (Wright Direct at 9)

> [T]he utility industry is emphasizing non-carbon-emitting resources as the preferred types of generation projects for the future. (Wright Direct at 11)

Achievement of this goal would leave the coal plants operating primarily for balancing wind generation and making sales into the MISO market. As I discuss in Section IV.C, the coal plants are poorly suited for load-following.

MidAmerican further discusses Iowa's renewable policies in Mr. Wright's Direct, at 12–13. Keeping uneconomic coal plants on line will not promote those policies.

B. Recommendations

Q: How should the Commission deal with MidAmerican's coal plants?

A: I recommend that the Commission:

- Require MidAmerican to justify any future designation of must-run or self-scheduled status for the Ottumwa, Louisa and Neal coal units.
- Put MidAmerican on notice that any future capital additions to Ottumwa, Louisa and Neal, other than to address immediate health and safety concerns, are subject to retrospective prudence review.
- Require MidAmerican to file for approval of annual capital expenditures for Ottumwa, Louisa and Neal, to ensure that MidAmerican is only investing in resources that remain economically used and useful for customers. The Commission may want to impose the same requirement on IP&L for those units, for consistency.

- Require MidAmerican to file a comprehensive analysis of the cost-effectiveness of each of its remaining coal units and a least-cost plan for replacing the uneconomic plants with purchases from existing resources and a portfolio of additional renewables, demand response, and storage.
- Determine whether any Commission rules or practices need to be amended to provide MidAmerican with reasonable assurance of recovery of the prudently incurred but undepreciated investments in uneconomic plants that are retired.

III. Performance and Costs of MidAmerican Coal Units

Q: What performance and cost components of the coal units have you reviewed?

A: I have compiled performance data on unit capacity factor, forced outage rate, availability and heat rate. I have also assembled cost data for fuel, variable O&M, fixed O&M, overheads, and capital additions.

A. Performance Measures

Q: Which performance measures have you compiled for the MidAmerican coal units?

A: Table 2 shows data on each coal unit’s 2017 capacity factor, 2017 heat rate, and four measures of forced-outage rates:

- The rates that MidAmerican assumed in the PROMOD runs.
- The actual average outage rate for 2013 to 2017.
- The rate that MidAmerican reports as being “recommended.”
- The average rate that MISO reports for coal units of the size of each of the MidAmerican units.

For most of the MidAmerican units, the PROMOD outage rates are [redacted] than historical rates, the average of comparable MISO units, and even MidAmerican's internal recommendations. The outage rates and hence the capacity factors in the PROMOD runs thus appear to be [redacted]

Table 2: Coal Plant Technical Performance – contains information marked CONFIDENTIAL

Plant	Unit	Operator	2017 Capacity Factor[a]	2017 Heat Rate[b] (Btu/kWh)	Forced Outage and Deration Rate (%)			
					PROMOD[c]	2013–17[d]	Recommended[d]	MISO[d]
Louisa	1	MEC	53.9%	10,960	[redacted]	[redacted]	[redacted]	7.9%
Ottumwa	1	IPL	65.2%	10,253	[redacted]	[redacted]	[redacted]	7.9%
Neal North	3	MEC	47.6%	10,384	[redacted]	[redacted]	[redacted]	7.0%
Neal South	4	MEC	43.1%	10,302	[redacted]	[redacted]	[redacted]	7.9%
Walter Scott	3	MEC	77.6%	10,662	[redacted]	[redacted]	[redacted]	7.9%
Walter Scott	4	MEC	55.4%	9,777	[redacted]	[redacted]	[redacted]	7.9%

[a] *DR OCA 14; results from EIA 860 and 923 are similar.*

[b] *2017 EIA Form 923.*

[c] *Sum of "EFOR" and "Equivalent Derate" in summary of PROMOD inputs, Coal Generating Unit Parameters, 2017 to 2031.*

[d] Attachment 1-SC4 Table 3b

[e] *"Planning Year 2018–2019 Loss of Load Expectation Study Report," Loss of Load Expectation Working Group, October 19, 2017, Table 4-1.*

After the Board granted Sierra Club's Motion to Compel, MidAmerican provided the historical plant outage rates by unit. Table 3 provides those data, which demonstrate the annual variability in plant performance. In four out of the five years, at least one unit experienced an outage rate in excess of [redacted]%. An average of [redacted] units each year had a forced outage rate exceeding [redacted]%.

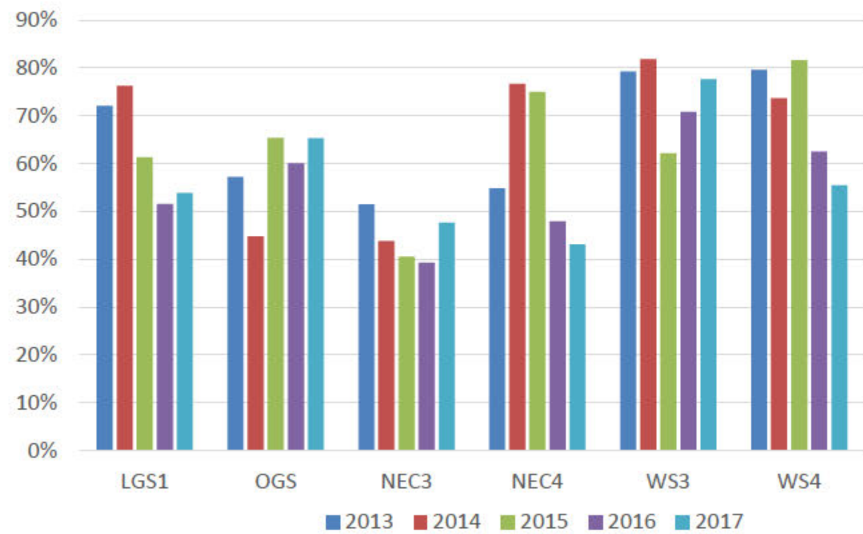
Table 3: [redacted]

Plant	Unit	2013	2014	2015	2016	2017	Average (2013–2017)
Louisa		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal North	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal South	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q: How has coal utilization changed over the past five years?

A: Yes. Figure 3 depicts annual capacity factors by unit for the last five years, from the FERC Form 1 reports.

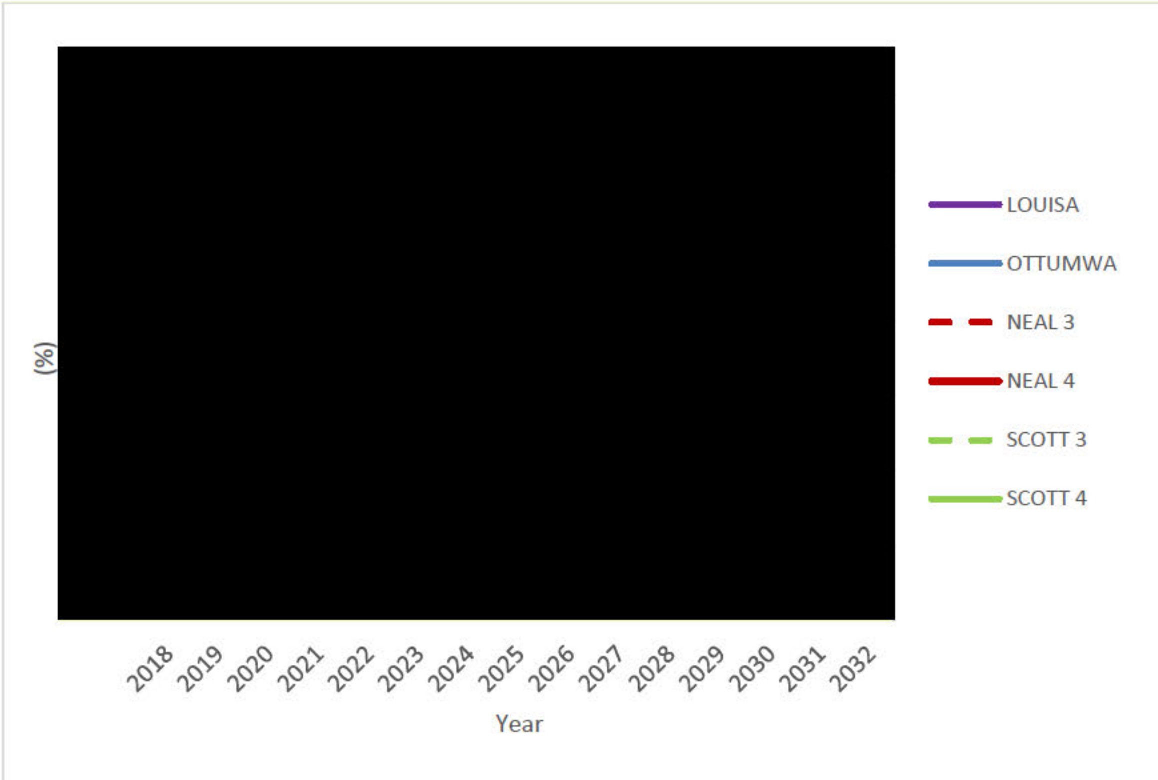
Figure 3: Capacity Factors by Unit (2013–2017)



In 2013, the fleet wide coal unit capacity factor was 66.9%; that had dropped to 57.7% by 2017. Overall, MidAmerican is generating less energy from its coal fleet. Capacity factors have fallen below fifty percent for Neal 3 and 4, while they hover near fifty percent for Louisa. MidAmerican's projections for coal plant utilization [redacted]

Figure 4 [Confidential] shows MidAmerican's annual capacity factor projections. While MidAmerican expects the Walter Scott units to [redacted] resources, partially due to their [redacted] and Ottumwa to operate at a capacity factor [redacted] (due to its [redacted]), it expects Neal 3 and 4 and Louisa to operate [redacted] and in some years well [redacted]

Figure 4: MidAmerican Forecast of Coal Unit Capacity Factors - CONFIDENTIAL



Note that the projected capacity factors for Walter Scott and Ottumwa are [redacted].

Q: What are the implications of the [redacted] projected capacity factors for the coal units?

A: As MidAmerican points out, coal plants are only cost-effective if they can operate profitably in most hours:

> Coal-fired units have a higher initial capital cost than most other conventional units, with the exception of nuclear resources. Therefore, to be economical, these units must operate at a relatively higher capacity factor, typically greater than 60%. (Hammer Direct at 38)

Indeed, Neal 1 and 2 ran at capacity factors from 30% to 43% in 2013 and were retired in 2016. Neal and Louisa have been running at less than Mr. Hammer's 60% capacity factor floor and [redacted]

[redacted]

B. Fuel and O&M

Q: What information do you have on the fuel and O&M costs of MidAmerican's coal units?

A: I have the following data on O&M:

- the fuel and O&M cost data that MidAmerican, IP&L and NorthWestern file in the FERC Form 1 reports for each unit,
- projected variable O&M by unit, which MidAmerican provided on July 17, 2018, PROMOD inputs in spreadsheet format, CONFIDENTIAL supplemental response to DR 2-SC-4 and 2-SC-5, [redacted],[5] attached as CONFIDENTIAL Ex. PLC-5A, and
- fuel costs by unit in [redacted].

Table 4 provides data on the fuel and total nonfuel O&M costs for each of the MidAmerican coal units, in dollars per megawatt-hour, from MidAmerican FERC Form 1 reports for those years, pages 402 and 403.

[5] Hereinafter referenced as "CONFIDENTIAL PROMOD inputs."

Table 4: Fuel and Non-Fuel O&M Costs by Unit ($/MWh)

Unit		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Louisa	**Total**	**20.00**	**23.90**	**22.80**	**24.00**	**23.00**	**29.80**
	Fuel	15.61	16.76	18.63	19.30	18.13	19.61
	O&M	4.39	7.14	4.17	4.70	4.87	10.19
Ottumwa	**Total**	**30.80**	**28.40**	**30.00**	**26.80**	**27.60**	**25.50**
	Fuel	23.78	22.38	21.26	20.01	19.70	19.23
	O&M	7.02	6.02	8.74	6.79	7.90	6.30
Neal 3	**Total**	**20.20**	**24.60**	**33.80**	**27.10**	**26.00**	**26.30**
	Fuel	15.60	18.78	19.64	19.50	18.05	18.25
	O&M	4.60	5.82	14.16	7.60	7.95	8.05
Neal 4	**Total**	**18.70**	**29.00**	**23.20**	**22.40**	**23.70**	**26.00**
	Fuel	14.79	17.85	18.47	17.97	17.27	19.17
	O&M	3.91	11.15	4.73	4.43	6.43	6.83
Scott 3	**Total**	**15.60**	**18.60**	**19.40**	**25.70**	**16.70**	**17.40**
	Fuel	11.46	14.08	14.77	13.51	12.53	13.58
	O&M	4.14	4.52	4.63	12.19	4.17	3.82
Scott 4	**Total**	**18.30**	**19.40**	**24.50**	**18.20**	**18.40**	**21.90**
	Fuel	12.38	14.14	15.05	13.89	13.44	13.82
	O&M	5.92	5.26	9.45	4.31	4.96	8.08

Table 5 summarizes MidAmerican's projection of variable O&M by unit for 2017. (CONFIDENTIAL Ex. PLC-5A). These variable O&M costs would be part of the total O&M reported in Table 4.

Table 5: [redacted]

Louisa		[redacted]
Ottumwa		
Neal 3		
Neal 4		
Scott 3		
Scott 4		

Q: Is there any indication that these prices will decline in the near future?

A: No. MidAmerican projects that its [redacted]. (CONFIDENTIAL Ex. PLC-5A, and [redacted], CONFIDENTIAL Ex. PLC-5B)

Q: Have you found generic estimates of O&M costs for coal plants comparable to MidAmerican?

A: The U.S. EPA estimated variable and fixed O&M for coal plants in a May 2018 report.[6] The variable O&M cost estimates are differentiated based on the SO_2, NOx and mercury control. All the MidAmerican units have dry flue-gas desulfurization for SO_2 and activated carbon injection for mercury control; Scott 4 has selective catalytic reduction (SCR), both Neal units have selective non-catalytic reduction (SNCR), and the other three units have neither of those controls.[7] The fixed O&M cost estimates are differentiated based on the same pollution controls and unit age (under 40 years, 40 to 50 years, and older).

Table 6 summarizes the results of applying the EPA categories to the MidAmerican coal units and applying 2% annual inflation from the 2016 dollars.

Table 6: EPA Non-Fuel O&M Estimates (2018$)

			Variable		Fixed O&M ($/kW-yr)			
		Year	O&M	Age at		Increase		Average
Plant	**Unit**	**Installed**	**$/MWh**	**1/2019**	**2019**	**in**	**to**	**2019-28**
Louisa		1983	$5.17	35	$39.62	2024	$43.85	$41.74
Ottumwa		1981	$5.17	37	$39.62	2022	$43.85	$42.58
Neal	3	1975	$6.14	43	$44.14	2026	$53.75	$47.03
Neal	4	1979	$6.14	39	$39.91	2020	$44.14	$43.72
Scott	3	1978	$5.17	40	$43.85	2029	$53.46	$43.85
Scott	4	2007	$6.17	11	$39.91	2048	$44.66	$39.91

[6] Documentation for EPA Base Case v.6 Using the Integrated Planning Model, EPA, May 2018, Tables 4-8 and 4-9. www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_4.pdf.

[7] 2017 Form EIA-860 Data - Schedule 6B, 'Emission Standards and Control Strategies'.

Q: How do the EPA estimates for O&M compare to the historical data for the MidAmerican units?

A: The 2017 O&M reported for the units was generally considerably lower than the EPA estimates. The discrepancy may arise in part from EPA including in its O&M estimates costs that the utilities report in the overhead categories I discuss in Section III.D. It is also possible that MidAmerican and IP&L have done a better job controlling costs at their units, which is laudable. Unfortunately, it may also indicate that further cost reductions will be difficult.

C. Capital Additions

Q: What information do you have regarding the ongoing capital costs for the MidAmerican coal plants?

A: I have compiled the historical additions to capital plant in service for the MidAmerican plants from the MidAmerican Form 1 reports for 2012–2017. MidAmerican provided historical data on expenditures for capital additions by unit in DR 2-SC-3h-m, four days before this testimony was due. MidAmerican has not provided any forecasts of capital additions, but I found some projections from IP&L for their jointly-owned units.

Q: What have been the historical capital additions for the MidAmerican units?

A: Table 7 lists the net annual capital additions by plant, computed from the change in capital cost reported in the annual FERC Form 1 reports.[8] These values represent the capital additions at the plant in the particular year, minus

[8] I eliminated the line for "Asset Retirement Costs," which are accounting allowances for future removal costs.

the retirements of equipment at that plant. The interim accounting retirements do not generally reduce revenue requirements, since an equal amount of accumulated depreciation is removed, leaving net plant in service unchanged, so the net additions understate the costs imposed on ratepayers. Where the capital cost declined from year to year, I left the cell blank.

Table 7: MidAmerican Net Capital Additions ($M)

	2013	2014	2015	2016	2017
Louisa	$7.3	$0.9	$3.7	$3.6	$40.0
Ottumwa	7.6	247.4	14.8	–	19.2
Neal 3	11.8	196.5	11.4	9.6	–
Neal 4	132.2	4.3	1.3	1.5	0.2
Walter Scott 3	3.6	3.2	27.8	8.5	–
Walter Scott 4	4.5	5.7	2.3	–	8.7

In Table 8, I convert those capital additions to $/kW by dividing by MidAmerican's ownership share of the unit, as well as the average capital additions over the last five years. Since these values are net of retirements, they understate the actual costs to ratepayers.

Table 8: MidAmerican Net Capital Additions ($/kW)

	2013	2014	2015	2016	2017	Average	Except Outliers
Louisa	$11.2	$1.4	$5.7	$5.5	$61.1	$17.0	
Ottumwa	$19.9	$651.1	$38.8		$50.5	$152.1	$36.4
Neal 3	$32.1	$532.5	$31.0	$25.9		$124.3	$29.7
Neal 4	$491.4	$16.0	$5.0	$5.5	$0.8	$103.7	$6.8
Scott 3	$6.4	$5.6	$49.3	$15.1		$16.8	
Scott 4	$9.3	$11.8	$4.8		$17.9	$7.9	

Some of these additions (e.g., Ottumwa and Neal 3 in 2014, Neal 4 in 2013) represent major environmental retrofits, which may not recur at the same level for many years, but most of the costs appear to be for smaller routine replacements and upgrades. I therefore also computed the average without those outliers.

Table 9 presents the same data, in dollars per kilowatt.

Table 9: MidAmerican Net Capital Additions ($/MWh)

	2013	2014	2015	2016	2017	Average	Except Outliers
Louisa	$1.8	$0.2	$1.1	$1.2	$13.0	$3.4	
Ottumwa	$4.7	$188.0	$8.0		$9.6	$52.6	$7.4
Neal 3	$7.5	$144.9	$8.7	$7.7		$42.2	$7.9
Neal 4	$121.8	$2.7	$0.9	$1.3	$0.2	$25.4	$1.3
Scott 3	$1.0	$0.8	$9.4	$2.5		$3.4	
Scott 4	$1.4	$1.9	$0.7		$3.7	$1.9	

Q: In addition to the public data you summarize in Table 7 through Table 9, what confidential data did MidAmerican provide on its coal-unit capital additions?

A: On July 30, 2018, MidAmerican finally provided confidential environmental and non-environmental capital additions for 2013 to 2017 for each of its coal units in response to DR 2-SC-3h-m. Comparison of the annual values to the data in the FERC Form 1 suggests that the data in DR 2-SC-3h-m are for annual expenditures (when MidAmerican spent money), not for the plant investment entering service in each year (when projects are completed and the costs are moved from "Construction Work in Progress" to "Plant in Service"). Table 10 summarizes those data.

Table 10: [redacted]

	2013	2014	2015	2016	2017
Environmental					
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Environmental					
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total					
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 11 shows the total capital additions, restated in dollars per kilowatt. Again, I also compute averages without the environmental costs in the high years.

Table 11: [redacted]

	2013	2014	2015	2016	2017	Average	Except Outliers
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Scott 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

These capital additions are [redacted] the net capital additions I compute from the FERC Form data in Table 8, other than the years in which the FERC Forms show [redacted].

Q: Did MidAmerican provide any forecasts of capital additions for its coal units?

A: No, but in RPU-2017-0002, IP&L provided non-confidential forecasts for capital additions for its shares of Louisa, Ottumwa, and Neal, attached as Exhibit PLC-2, IP&L Response to DR 1-SC-7, RPU-2017-0002. Table 12 shows those estimates, restated to dollars per kilowatt for IP&L's share of the units.[9]

Table 12: IP&L Forecasts of Coal Capital Additions ($/kW)

	2017	2018	2019	2020	Average
Louisa	$82.5	$15.9	$13.4	$13.4	$31.3
Ottumwa	$121.8	$85.6	$27.6	$48.4	$70.8
Neal	$27.3	$32.0	$21.8	$21.7	$47.9
Source: IP&L Response to DR 1-SC-7, RPU-2017-0002					

The average capital additions that IP&L forecasts are broadly similar to the historical averages in Table 8 and Table 11.

Q: Have you found any generic projections of coal-plant capital additions to supplement the data you found for the MidAmerican units?

A: Yes. In preparing the 2018 Annual Energy Outlook, which included an economic analysis of continued plant operation, the Energy Information Administration (EIA) estimated the average annual capital additions for coal plants, among other technologies.

> The average annual capital additions for existing plants are…$18 per kW for coal plants…(in 2017 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age, an additional $7 per kW capital charge for fossil plants…to

[9] Those shares are 30 MW for Louisa, 345 MW for Ottumwa, and 308 MW for Neal (assuming that the IP&L data include the 143 MW of Neal #3 owned by IP&L affiliate IES Utilities).

> reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.[10]

This analysis suggests that the MidAmerican coal units would have capital additions of $25/kW-year, except for Walter Scott 4, which would spend $18/kW-year. The IP&L forecast of Louisa's capital additions is close to the generic estimates, while those for Ottumwa and Neal are significantly higher than the generic estimates. The historical capital additions for Walter Scott are lower than the generic values.

D. Overheads

Q: What other costs are associated with continuing operation of the marginal coal units?

A: In addition to the O&M costs reported in the FERC Form 1 (e.g., page 402) for each plant, running the coal units incurs other costs that are recorded in other accounts, including:

- Labor-related overheads, such as social security, unemployment taxes, pensions, and benefits (e.g., health and life insurance, education assistance).
- Property insurance.
- Property taxes.
- Administrative costs, such as legal, human resources, supervision, regulatory and public affairs.
- Office expenses related to administration.

[10] Assumptions to the Annual Energy Outlook 2018, EIA, April 2018, Electricity Market Module, page 13: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

- Maintenance of the step-up transformers and other dedicated transmission equipment.

Q: How large are these indirect costs?

A: One way to address that question is to examine the extent to which the lead owner of each plant marks up its O&M costs to include these other costs. Four MidAmerican coal units are jointly owned with IP&L, which is the lead owner of Ottumwa and also owns portions of Louisa, Neal 3 and Neal 4, and NorthWestern, which owns part of Neal 4. In general, the lead owner of a jointly owned plant carries most of the non-generation accounts on its own books and charges the point owners for their share of direct operating costs and of the indirect costs. From the 2014 to 2017 FERC Form 1 data for the various owners, the non-fuel O&M per kWh charged to the joint owner exceeds that reported by the lead owner by 40% to 58%, as shown in Table 13.

Table 13: Implied Overheads, Non-Fuel O&M

		$/kWh				Markup		
		MidAm	IPL	NW		MidAm	IPL	NW
2017	Louisa	0.0102	0.0123				1.21	
2017	Ottumwa	0.0063	0.0041			1.52		
2017	Neal 3	0.0081	0.0128				1.58	
2017	Neal 4	0.0068	0.0107	0.0112			1.56	1.64
2016	Louisa	0.0049	0.0075				1.54	
2016	Ottumwa	0.0079	0.0045			1.76		
2016	Neal 3	0.0079	0.0125				1.58	
2016	Neal 4	0.0064	0.0102	0.0102			1.59	1.58
2015	Louisa	0.0047	0.0067				1.41	
2015	Ottumwa	0.0068	0.0041			1.66		
2015	Neal 3	0.0076	0.0124				1.62	
2015	Neal 4	0.0045	0.0066	0.0054			1.47	1.21
2014	Louisa	0.0041	0.0060				1.44	
2014	Ottumwa	0.0087	0.0064			1.36		
2014	Neal 3	0.0142	0.0172				1.21	
2014	Neal 4	0.0047	0.0066	0.0068			1.38	1.43
Average	Louisa						1.40	
Average	Ottumwa					1.58		
Average	Neal 3						1.50	
Average	Neal 4						1.50	1.47

The prices reported by MidAmerican for Ottumwa already include the overheads added by IP&L. The markups are very similar among the three utilities and the four units.

In addition, as shown in Table 14, the Neal joint owners also pay about 8% more than MidAmerican does for their fuel, suggesting that there are overheads excluded from MidAmerican's reported Neal fuel costs, as well. The Louisa fuel costs reported for the two owners are very similar, and the differences may reflect minor accounting and timing differences.

Table 14: Implied Overheads, Fuel

		$/kWh				**Markup**		
		MidAm	**IPL**	**NW**		**MidAm**	**IPL**	**NW**
2017	Louisa	0.0196	0.0196				1.00	
2017	Ottumwa	0.0192	0.0194			0.99		
2017	Neal #3	0.0182	0.0199				1.09	
2017	Neal #4	0.0192	0.0209	0.0217			1.09	1.13
2016	Louisa	0.0181	0.0187				1.03	
2016	Ottumwa	0.0197	0.0196			1.01		
2016	Neal #3	0.0180	0.0198				1.10	
2016	Neal #4	0.0173	0.0184	0.0184			1.07	1.07
2015	Louisa	0.0193	0.0194				1.01	
2015	Ottumwa	0.0200	0.0200			1.00		
2015	Neal #3	0.0195	0.0204				1.05	
2015	Neal #4	0.0180	0.0189	0.0193			1.05	1.07
2014	Louisa	0.0186	0.0183				0.98	
2014	Ottumwa	0.0213	0.0209			1.02		
2014	Neal #3	0.0196	0.0203				1.04	
2014	Neal #4	0.0185	0.0197	0.0200			1.07	1.08
Average	Louisa						1.01	
Average	Ottumwa					1.00		
Average	Neal #3						1.07	
Average	Neal #4						1.07	1.09

From these comparisons, it appears that the indirect O&M costs not reflected in the unit-specific data are on the order of 50% of direct non-fuel O&M, plus about 7% of fuel costs for Neal.

Since I do not have any direct data for the overheads on Walter Scott, I will assume that those overheads are 50% of non-fuel O&M, and 0% of fuel.

E. Cost Summary

Q: How do the cost components (fuel, O&M, overheads and capital expenditures) add up to a cost per megawatt-hour for continued operation?

A: Table 15 shows the total costs of keeping each coal unit running, from 2013 to 2017, using the public data that I develop above.

Table 15: Costs of Running MidAmerican Coal Units ($/MWh)

		OH Adder	2013	2014	2015	2016	2017
Louisa	Fuel		$16.76	$18.63	$19.30	$18.13	$19.61
	O&M	50%	$7.14	$4.17	$4.70	$4.87	$10.19
	Capital Additions		$1.77	$0.21	$1.06	$1.21	$12.91
	Overheads		$3.57	$2.09	$2.35	$2.44	$5.10
	Total Cost		$29.24	$25.09	$27.41	$26.65	$47.80
Ottumwa	Fuel		$22.38	$21.26	$20.01	$19.70	$19.23
	O&M		$6.02	$8.74	$6.79	$7.90	$6.30
	Capital Additions		$4.68	$188.02	$8.04		$9.57
	Overheads						-
	Total Cost		$33.08	$218.02	$34.84	$27.60	$35.10
Neal #3	Fuel	7%	$18.78	$19.64	$19.50	$18.05	$18.25
	O&M	50%	$5.82	$14.16	$7.60	$7.95	$8.05
	Capital Additions		$121.83	$2.71	$0.86	$1.31	$0.22
	Overheads		$6.82	$3.66	$3.47	$4.42	$4.76
	Total Cost		$157.66	$29.56	$26.73	$29.44	$30.98
Neal #4	Fuel	7%	$17.85	$18.47	$17.97	$17.27	$19.17
	O&M	50%	$11.15	$4.73	$4.43	$6.43	$6.83
	Capital Additions		$102.49	$2.38	$0.76	$1.31	$0.21
	Overheads		$6.82	$3.66	$3.47	$4.42	$4.76
	Total Cost		$138.32	$29.24	$26.63	$29.43	$30.97
Walter Scott 3	Fuel		$14.08	$14.77	$13.51	$12.53	$13.58
	O&M	50%	$4.52	$4.63	$12.19	$4.17	$3.82
	Capital Additions		$0.95	$0.82	$9.40	$2.51	-
	Overheads		$2.26	$2.32	$6.10	$2.09	$1.91
	Total Cost		$21.81	$22.54	$41.20	$21.30	$19.31
Walter Scott 4	Fuel		$14.14	$15.05	$13.89	$13.44	$13.82
	O&M	50%	$5.26	$9.45	$4.31	$4.96	$8.08
	Capital Additions		$1.36	$1.88	$0.68		$3.75
	Overheads		$2.63	$4.73	$2.16	$2.48	$4.04
	Total Cost		$23.39	$31.10	$21.03	$20.88	$29.69

Excluding years with extraordinary capital additions, the all-in cost of keeping Scott 3 operating has been around $20/MWh, while Scott 4 has cost $20/MWh–$30/MWh in various years. Neal 4 has cost $25/MWh to $30/MWh, Neal 3 has cost $30/MWh to $40/MWh, Ottumwa has cost about $30/MWh to $35/MWh and Louisa cost $25/MWh to $30/MWh, spiking to $50/MWh in 2017.

The capital additions, and hence the total costs, would generally be [redacted] with the actual annual expenditures.

IV. Market Energy Prices for MidAmerican's Coal Units

A. MISO Energy Prices

Q: What MISO market energy prices have the MidAmerican coal units faced?

A: Table 16 provides summary price statistics for the market price (the day-ahead LMP) at the energy node for each MidAmerican unit in 2017. The market prices vary among the four plants, but not within the two-unit plants.

Table 16: Hourly Energy Prices ($/MWh) by Unit (2017)

	Ottumwa	Louisa	Neal 3	Neal 4	Scott 3	Scott 4
Mean	$22.2	$25.1	$23.1	$23.1	$23.9	$23.9
Minimum	-333.0	-55.4	-11.0	-11.0	-19.8	-19.8
25th Percentile	18.0	19.7	17.2	17.2	17.5	17.5
50th Percentile	20.7	22.3	20.8	20.8	20.9	21.0
75th Percentile	25.3	26.9	25.5	25.5	25.9	25.9
Maximum	407.4	370.4	356.6	356.4	366.7	366.7

Q: How do these energy prices compare to the short-run costs of producing energy prices from these units?

A: Table 17 summarizes that comparison. I started by estimating the short-run cost for each unit as the sum of 2017 fuel costs from Table 4 and MidAmerican's forecast of variable O&M from Table 5. I then counted the number of hours in which the market energy price exceeded the short-run cost. These values varied from less than [redacted] of the hours for Neal 4 to almost [redacted] of the hours for Walter Scott 3. I also computed the average LMP in the hours when it exceeded the short-run cost. The LMP in those profitable hours varies inversely with the number of profitable hours.[11]

[11] In this section, I consider whether the units are profitable to run in a particular hour, once MidAmerican has committed to capital additions and fixed O&M. Elsewhere, I consider the annual profitability of the units, including the capital additions and fixed O&M. I do not reflect the sunk capital costs of the units in any of my analyses.

Table 17: [redacted]

	Louisa	Ottumwa	Neal 3	Neal 4	Scott 3	Scott 4
Fuel + VOM ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
When LMP exceeds Fuel + VOM						
Number of Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
% of hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average LMP ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Energy Margin = LMP – (Fuel + VOM)						
$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$/kW-year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

In the last section of Table 17, I computed the average energy margin for each unit in the profitable hours, in dollars per megawatt-hour (the difference between average LMP and the variable running cost) and in $/kW-year (the $/MWh margin times the number of profitable hours).

Q: How does the percentage of profitable hours compare to the units' capacity factors?

A: Other than Ottumwa, the units generated less energy than they would have if they ran at full power in every profitable hour, and not in any unprofitable hour, as shown in Table 18.

Table 18: Comparison of Profitable Hours to Capacity Factors, 2017 CONFIDENTIAL

	Louisa	Ottumwa	Neal 3	Neal 4	Scott 3	Scott 4
Profitable Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Factor	53.9%	65.2%	47.6%	43.1%	77.6%	55.4%
Difference	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

If the coal units were always available and able to ramp up immediately to full power in the profitable hours and shut down immediately when LMP fell, the capacity factor should be very close to the profitable hours. In reality, the capacity factor for each unit is reduced by forced and maintenance outages. In addition, the coal units cannot cycle up and down fast enough to run in all the profitable hours without running in unprofitable hours. Table 18 shows that most of the units had capacity factors lower than the percentage of hours in which operation would be profitable, as a result of outages and ramping limitations. The exception is Ottumwa, which appears to be dispatched when it is not profitable.

B. MidAmerican Reports of Historical Energy Revenue

Q: Did MidAmerican provide the energy revenues its coal units have received?

A: Yes. Table 19 shows the energy revenue by unit, using the annual revenues from DR 2-SC-3 h-m (marked confidential), which MidAmerican finally provided on July 30, and the energy output from MidAmerican's share of the unit, from the FERC Forms.[12]

Table 19: [redacted]

	2014	2015	2016	2017	Average
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal #3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal #4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott #3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott #4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The revenues received per MWh for each unit tend to be lower than the market price in the hours when the unit was economic to operate, since MidAmerican cannot dispatch the units only in the hours in which they are profitable.

[12] Since MidAmerican sells 50 MW of Scott 3 and purchases 50 MW of Scott 4, the energy and revenue data for these units do not quite line up. The revenue for each of these units would be roughly the average shown for the two units for the hour.

Q: How do the revenues you have computed compare to the costs of running the units?

A: Table 20 reports each unit's annual operating profit for each year 2014 through 2017, using the cost data in Table 15, except the capital additions for Table 10, and the revenues from Table 19.[13]

Table 20: [redacted]

	2014	2015	2016	2017	Average
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Scott 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Ottumwa and Neal 3 [redacted] every year, while Louisa, Neal 4 and Scott 3 have [redacted] on average, and Scott 4 was [redacted] on average.

Q: How much [redacted] would MidAmerican customers [redacted] annually in order to keep the coal plants operating, at the profit levels in Table 22?

A: MidAmerican customers would pay [redacted] annually at the 2017 unit output levels.

C. Cycling Ability of MidAmerican Coal Units

Q: To what extent can the MidAmerican coal units vary their output in response to changes in load or market energy prices?

A: In general, large coal units are very slow to respond to changing conditions. Very little public information is available on these technical parameters, but

[13] These values reflect only energy revenues. Capacity revenues are discussed in Section [redacted]. While the units would also receive some ancillary revenues, most of those costs are charged to Iowa load, so the ancillary revenues are not a benefit to Iowa customers overall.

according to EIA's Form 860, MidAmerican's coal units all require "more than 12 hours" from cold shutdown to full load, while most of its other fossil units require 10 minutes to one hour to reach full load.[14]

Table 21 elaborates on the limited load-following abilities of each of the MidAmerican coal units, from CONFIDENTIAL PROMOD inputs.[15] The various units require [redacted] to [redacted] hours to reach minimum load from a cold start, and [redacted] to [redacted] hours from a hot start. Once a unit is running, it must stay in operation for [redacted] to [redacted] hours; once it is shut down, it cannot come back up for [redacted] to [redacted] hours.[16] Ramping up from minimum load to maximum load requires [redacted] to [redacted] hours, and getting back down to minimum load requires [redacted] to [redacted] hours.

Table 21: [redacted]

	Louisa	Ottumwa	Neal 3	Neal 4	Scott 3	Scott 4
Start time (hours), after shutdown of						
[redacted] hours (cold)			[redacted]	[redacted]	[redacted]	[redacted]
[redacted] hours (intermediate)			[redacted]	[redacted]	[redacted]	[redacted]
<[redacted] hours (hot)			[redacted]	[redacted]	[redacted]	[redacted]
Ramp rate (MW/minute)						
Up	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Down	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min Up Time (hours)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min Down Time (hours)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min load as % max load	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ramp time (hours)						
Min to max	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Max to min	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[14] The exceptions are the Riverside 5 steam plant and the Greater Des Moines combined-cycle plant. Most combined-cycle plants can reach a substantial share of the capacity of the combustion turbines in less than an hour, although the heat-recovery steam generator may take longer to reach full capacity.

[15] The response omitted start-time data for Louisa and Ottumwa.

[16] The minimum down times are so long for some units that they do not appear to be able to make hot starts, unless perhaps by burning additional fuel to keep the boilers warm during the required down time.

according to EIA's Form 860, MidAmerican's coal units all require "more than 12 hours" from cold shutdown to full load, while most of its other fossil units require 10 minutes to one hour to reach full load.[14]

Table 21 elaborates on the limited load-following abilities of each of the MidAmerican coal units, from CONFIDENTIAL PROMOD inputs (Ex. PLC-5A).[15] The various units require [redacted] to [redacted] hours to reach minimum load from a cold start, and [redacted] to [redacted] hours from a hot start. Once a unit is running, it must stay in operation for [redacted] to [redacted] hours; once it is shut down, it cannot come back up for [redacted] to [redacted] hours.[16] Ramping up from minimum load to maximum load requires [redacted] to [redacted] hours, and getting back down to minimum load requires [redacted] to [redacted] hours.

Table 21: [redacted]

	Louisa	Ottumwa	Neal 3	Neal 4	Scott 3	Scott 4
Start time (hours), after shutdown of						
[redacted] hours (cold)			[redacted]	[redacted]	[redacted]	[redacted]
[redacted] hours (intermediate)			[redacted]	[redacted]	[redacted]	[redacted]
<[redacted] hours (hot)			[redacted]	[redacted]	[redacted]	[redacted]
Ramp rate (MW/minute)						
Up	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Down	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min Up Time (hours)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min Down Time (hours)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Min load as % max load	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ramp time (hours)						
Min to max	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Max to min	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[14] The exceptions are the Riverside 5 steam plant and the Greater Des Moines combined-cycle plant. Most combined-cycle plants can reach a substantial share of the capacity of the combustion turbines in less than an hour, although the heat-recovery steam generator may take longer to reach full capacity.

[15] The response omitted start-time data for Louisa and Ottumwa.

[16] The minimum down times are so long for some units that they do not appear to be able to make hot starts, unless perhaps by burning additional fuel to keep the boilers warm during the required down time.

The operating limitations of these units do not allow them to follow rapid or large swings in net load. They are poorly suited to operate in the wind-rich system that MidAmerican envisions and that is emerging as utilities and other generators add wind capacity (and increasingly, solar capacity) in the Midwest and Plains.

> [W]e do not see customer preferences for renewable energy changing in the future. Given this, as load grows, MidAmerican will continue to pursue environmentally sustainable, cost-effective options to continue to fulfill its 100% renewable vision. (Wright Direct at 10)

Q: How do the market energy prices compare to the costs of keeping the coal units in operation?

A: Table 22 compares the publicly-reported total cost of each unit per kWh in 2017 (from Table 15) to the average LMP in the hours in which the unit would have been profitable (from Table 17).

Table 22: Comparison of LMP to Ongoing Costs (2017) - CONFIDENTIAL

	Louisa	Ottumwa	Neal 3	Neal 4	Scott 3	Scott 4
Total Cost ($/MWh)	$47.80	$34.55	$31.60	$30.97	$19.31	$29.70
When LMP exceeds Fuel + VOM						
Average LMP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Profit/Loss $/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$/kW-year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

It appears that [redacted] Walter Scott 3 [redacted], with Neal 4 incurring [redacted], Louisa incurring [redacted] and the other three units [redacted]/kW-year. The results of similar comparisons will vary from year to year. These results do not reflect the confidential data on capital expenditures, which would [redacted].

V. MidAmerican's Capacity Situation

A. Capacity Surplus

Q: Does MidAmerican need the capacity from the all of its coal plants?

A: No. MidAmerican's load and capacity forecast in Mr. Hammer's Table 3 shows a surplus (above required reserves) of 674 MW in 2020, and more than 400 MW through 2025. Those values do not include the 92 MW of capacity from Wind XII, which Mr. Hammer chooses to exclude until 2032, even though he acknowledges that "it is likely that Wind XII's 591 MW of new wind capability will provide 92 MW of accredited capacity by its completion in 2020." (Hammer Direct at 13). Including the capacity value of Wind XII, the surpluses would be as shown in Table 23.

Table 23: MidAmerican Capacity Surplus with Wind XII

Planning Year	UCAP Surplus (MW)
2019-20	585
2020-21	673
2021-22	718
2022-23	672
2023-24	615
2024-25	558
2025-26	502
2026-27	446
2027-28	387
2028-29	335
2029-30	282
2030-31	232
2031-32	179
2032-33	-274

Development of additional wind capacity (as MidAmerican plans), solar capacity (either at utility scale or behind the meter) and/or storage would increase these surpluses over time.

Q: How do these surpluses compare to the accredited unforced capacity values of the MidAmerican coal entitlements?

A: MidAmerican provides the MISO-accredited UCAP capacity for each unit in Confidential Attachment 1-SC4 Table 3b. Unfortunately, the various capacity measures in that document do not consistently match the capacity values in Mr. Hammer's Table 2, so I applied the unit-specific ratio of UCAP to installed capacity (ICAP) from Attachment 1-SC4 Table 3b to the unit ICAP from Mr. Hammer's Table 2.

The capacity surplus would exceed MidAmerican's share of Louisa until 2023, Scott 4 until 2025, Scott 3 to 2026, Ottumwa until 2028, Neal 3 until 2029, and Neal 4 until 2030. MidAmerican could retire a unit and still meet its MISO capacity obligation for as much as a decade, without adding any capacity; additional wind and/or solar (either on the utility side or behind the meter) would further delay the need for other resources.

B. Capacity Prices

Q: Is the excess capacity very valuable in the MISO market?

A: No. Table 24 shows the clearing prices in Zone 3 (which includes the MidAmerican and IP&L territories and almost all of Iowa) for each of the Planning Reserve Auctions (PRAs) that MISO has conducted.[17]

[17] From "2018/2019 Planning Resource Auction Results," MISO, April 13, 2018, p. 8.

Table 24: MISO Zone 3 Capacity Prices

Planning Year	Per unit of UCAP		$/kWh at capacity factor of		
	$/MW-day	$/kW-year	40%	50%	60%
2014/15	$16.75	$6.11	$1.74	$1.40	$1.16
2015/16	$3.48	$1.27	$0.36	$0.29	$0.24
2016/17	$72.00	$26.28	$7.50	$6.00	$5.00
2017/18	$1.50	$0.55	$0.16	$0.13	$0.10
2018/19	$10.00	$3.65	$1.04	$0.83	$0.69
Average	$20.75	$7.57	$2.16	$1.73	$1.44

Zone 3 has always cleared at the same price as Zones 2, 5, 6, and 7, and usually with other zones, as well. In three of the five PRAs (those with Zone 3 prices over $4/MW-day), Zone 1, Iowa's northerly neighbors, cleared at much lower prices than Zone 3. If transmission capacity out of Zone 1 increases (to allow wind exports, or better integrate the MISO system), the capacity surplus in Zone 1 is likely to reduce prices in Zone 3.

There is no clear trend in the capacity prices over the five capacity auctions, despite the large amount of coal capacity retired in this period.

Q: How do these capacity prices compare to the operating losses that you computed for the MidAmerican coal units in Table 22?

A: The capacity price in 2017 was not enough to bring any [redacted]. If the costs and other revenues in 2018 are similar to those in 2017, [redacted] with 2018 capacity prices. The capacity price would need to be well above the historical average to [redacted]

Q: If MidAmerican needed to purchase additional capacity to meet its MISO obligations, would that be expensive?

A: Not at the historical average market capacity prices. As shown in Table 24, the cost of capacity to replace generation with the range of capacity factors that the MidAmerican coal units are likely to achieve is only about one or two dollars per MWh. If the coal energy is replaced by lower-cost wind, which has some capacity value, the cost of supplementary capacity purchases would be even lower.

VI. Trends in Coal-Plant Economics and Retirements

A. Historical Retirement Patterns

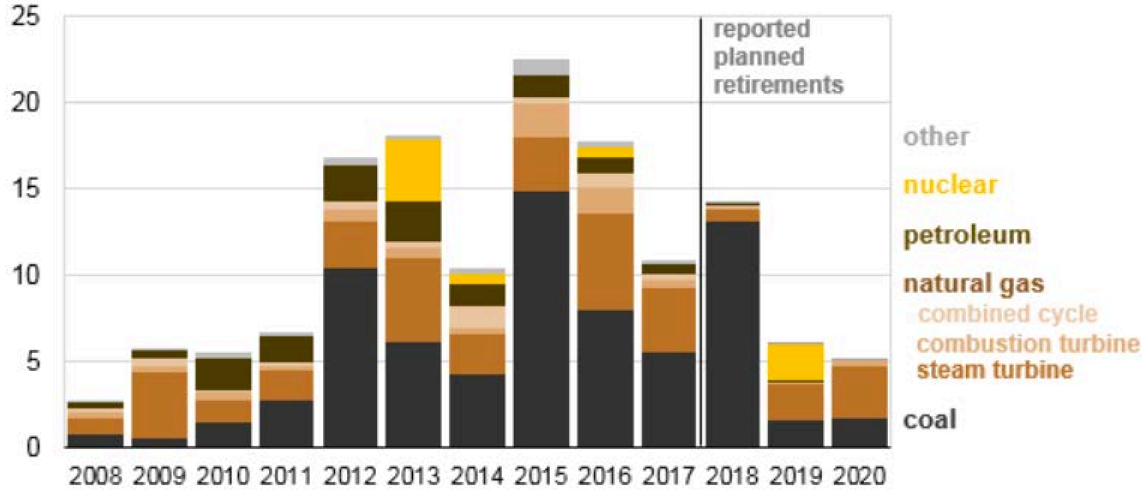
Q: How much coal-fired capacity has retired nationally over the past decade?

A: Over the past decade, United States generation owners have retired 117 GW of utility-scale generating capacity. Coal retirements have accounted for 47% of the total.[18] In the Eastern Interconnection (which includes MISO and hence MidAmerican), nearly 20% of coal generation has retired, generally replaced by natural gas generation and renewables.

Figure 5 plots retirements by year and fuel type. Notice both the overall increase in fossil fuel retirements and the increasing share of retirements coming from coal generation.

[18] EIA, Today in Energy, Almost All Power Plants that Retired in the Past Decade were Powered by Fossil Fuels (Jan. 9, 2018), www.eia.gov/todayinenergy/detail.php?id=34452.

Figure 5: U.S. Electric Generation Retirements (GW)



Reproduced from *Today in Energy*, EIA, January 9, 2018

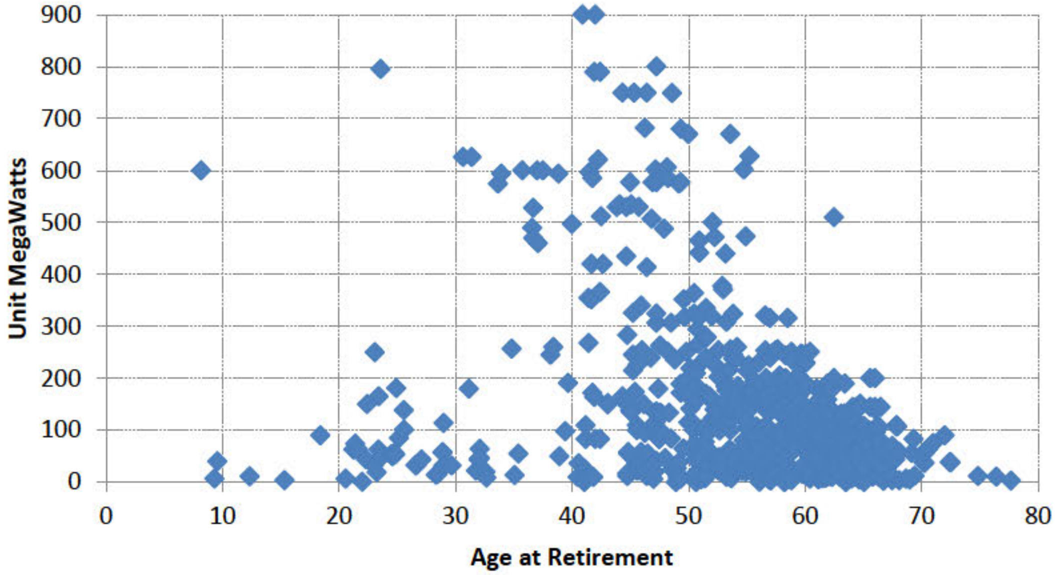
Q: At what age have coal plants tended to retire?

A: Most of the coal plants retired in the twenty-first century were between 20 and 65 years old when they shut down. Figure 6 shows the age at retirement of each retired coal unit owned by a utility or an independent power producer (IPP) and the unit's summer capacity.[19] I have also included units with announced retirement dates and those that have been permanently taken out of service, with no expectation of renewed operation, or converted to another fuel (mostly natural gas or biomass). These EIA data include past retirements since 2002 and announced retirements through 2027.[20]

[19] Data are from EIA Form 860 database.

[20] The data may exclude some units that have been retired and demolished, as opposed to being retired in place.

Figure 6: Coal-Plant Age at Retirement



Source: Data are from EIA Form 860 database

Q: What inferences can be drawn from the data underlying Figure 6, regarding the historical distribution of coal-plant lifetimes?

A: Using the raw data underlying Figure 6, I calculated survivorship by age. Overall, the dataset includes 327,252 MW of capacity at 1,305 units. As lifespan increases, more plants retire, reducing the share of plants that survive past that age, which is the survivorship rate. The survivorship curve is computed in three steps:

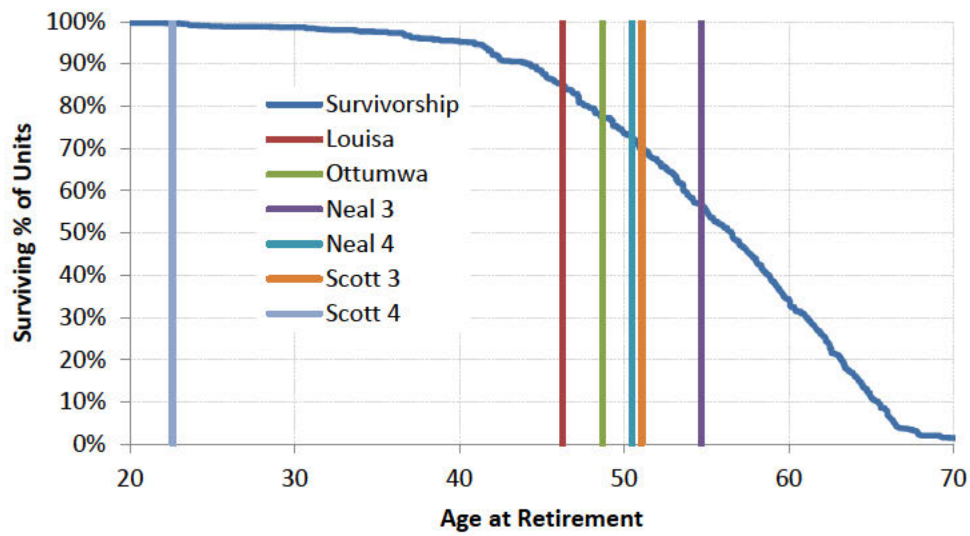
1. Sorting the utility and IPP units for which data are available by lifespan, that is, current age if the unit is still operational, or the age at retirement for retired units. The data set includes all the coal plants in EIA's Form 860 database for 2003, and counts as retirements the units that EIA lists in 2017 as retired, scheduled for retirement, out of service (with no expectations of a return to service) or switched to other fuel (mostly natural gas and biomass).[21]

[21] Including the out-of-service units and fuel switches does not noticeably affect the shape of the curve.

2. Dividing the capacity of the units retiring in a given year by the capacity that could have reached that age (i.e., units older than that age), to determine the mortality rate at that age.
3. Starting with 100% survivorship at age 1, multiplying the survivorship at each age (one minus mortality rate) by the cumulative survivorship in the age interval.

Figure 7 shows the survivorship curve, along with the age of each MidAmerican unit at the end of 2029.

Figure 7: Historical Coal Plant Survivorship, MidAmerican Plants in 2029



A quarter of all coal generation has retired before reaching the age of 50 years, half before 57 years, and three-quarters before 63 years. These results apply to the entire data set, which includes several years prior to the decline in gas prices and the cost of new renewables. As I explain below, retirements have been accelerating in recent years. And as I describe in Section VI.B, a large fraction of the national coal-plant fleet appears to be uneconomic.

If the historical survivorship curve continue to apply, the probability of all the units surviving the 2020s would be less than 19%.

Q: When does MidAmerican expect to retire its coal units?

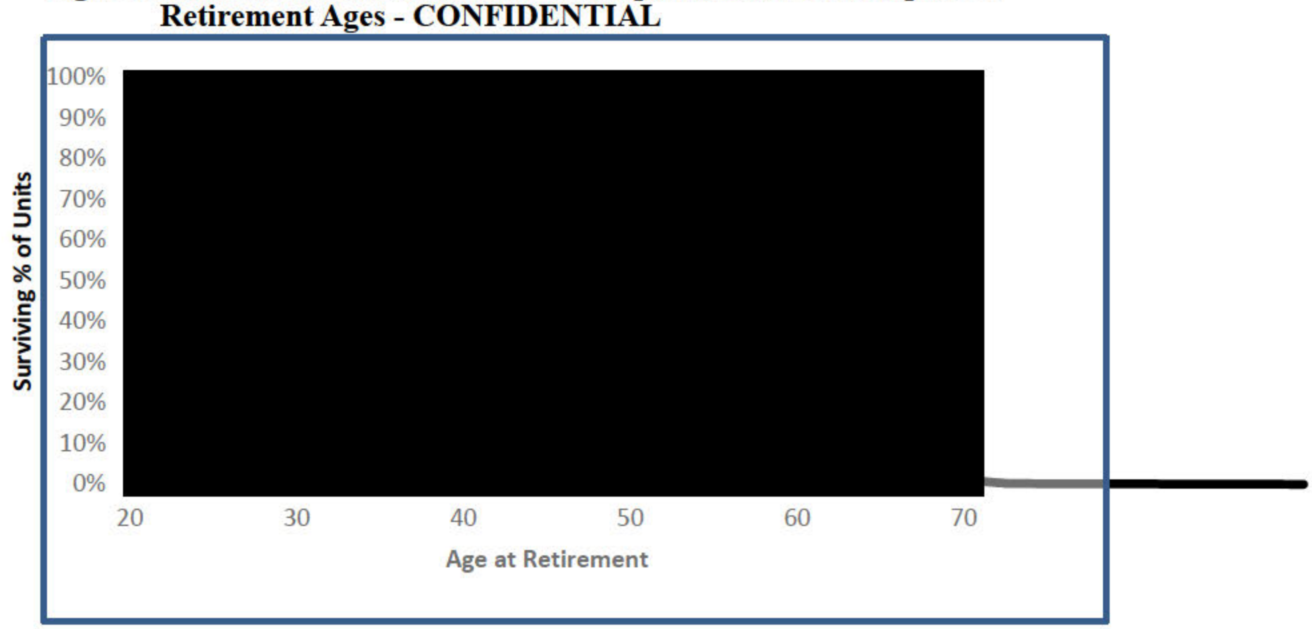
A: That is not clear. According to MidAmerican's response to DR 2-SC-6, no plant retirements have been forecasted. Yet the workpapers for Mr. Hammer's Table 3 load and capability forecast (CONFIDENTIAL Attachment 1-SC-4, Table 3b, Summary sheet) identify plant retirement dates, as shown in Table 25.[22]

Table 25: [redacted]

Unit	Projected Retirement	Age at Retirement
Louisa	[redacted]	[redacted]
Ottumwa		
Neil 3		
Neil 4		
WSEC 3		
WSEC 4		

Those dates are shown in Figure 8, along with the survivorship curve.

Figure 8: Historical Coal Plant Survivorship, MidAmerican Reported Retirement Ages - CONFIDENTIAL



[redacted]

[22] In the PROMOD runs, MidAmerican assumes that the coal units will all operate through the end of the analysis in [redacted].

Given the historical experience, the probability of all the coal units surviving to the dates shown in Table 25 would be about 0.3%.

Q: Is there reason to believe that coal plants are being retired even earlier than the long-term survivorship analysis would indicate?

A: Yes, the overall lifespan of plants is decreasing across the US and the size of units retiring has been increasing.

Over the past few years, younger and younger coal plants are being retired in the US. An analysis by Lawrence Berkeley National Laboratory indicated that the median retirement age for coal units projected to shut down between 2017–2023 would be 40–50 years old, rather than the 50–60 years for units retired between 2010 and 2016.[23]

M.J. Bradley & Associates also found that retirements are affecting larger and younger units over time:

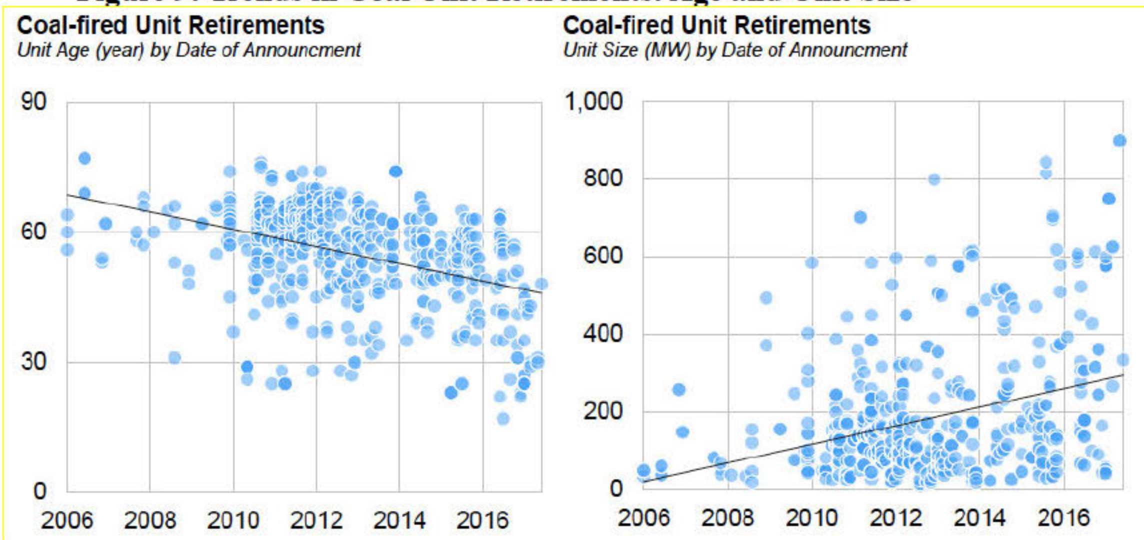
> On average, units that announced plans to retire between 2010 and 2015 were 57 years old and only 166 MW. By contrast, units that have announced plans to retire since 2016 are only 42 years old and 336 MW on average.[24]

Figure 9 reproduces M.J. Bradley's analysis of the time trends in size and age of coal retirements.

[23] Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, "Power Plant Retirements: Trends and Possible Drivers," Fig. 3 (Nov. 2017), https://emp.lbl.gov/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.

[24] "Coal-Fired Electricity Generation in the United States and Future Outlook," MJB&A Issue Brief, August 28, 2017.

Figure 9: Trends in Coal Unit Retirements: Age and Unit Size



B. Other Studies of Coal-Plant Economics

Q: Have other recent studies reviewed the prospects for economic coal plant operation?

A: Yes. Bloomberg New Energy Finance (BNEF) and the Brattle Group have conducted separate analyses of coal-plant cost-effectiveness in 2018.

1. The BNEF Study

Q: What did the BNEF study examine?

A: The Bloomberg study, attached as Exhibit PLC-3, covered the six-year period of 2012 through 2017, for 903 units totaling 280 MW of nameplate capacity, excluding combined heat and power units.[25] The authors compared energy, capacity and byproduct revenues by unit to the fuel, variable O&M and emissions charges, to compute what they call the "short-run margin." Adding fixed O&M to the costs produces the "long-run margin." The study reports

[25] Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide, William Nelson and Sophia Liu, March 26, 2018.

environmental capital additions, but does not include any capacity additions in the profitability analysis.

Q: What did the BNEF study conclude?

A: The study's conclusions included the following:

> By our estimates, 48% of the coal fleet (135 of 280 GW) posted negative margins from 2012-17…
>
> We find ourselves awestruck by the resilience of U.S. coal. Plants persist even when they cost more to run than replace. As we hunt for coal closures, beware of the sometimes tenuous link between 'economics' and 'retirement decisions'. The link is especially weak in regulated regions, where high-cost coal runs regularly out of merit. …
>
> The majority of 'uneconomic' units (130GW of 135GW) are regulated. They are kept online by virtue of cost-plus pacts that partially insulate owners from shifting economics. … (p. 1)
>
> Coal plants were originally designed to run baseload – to sell large volumes of electricity with healthy short-run operating margins (i.e. dark spreads). This was necessary to cover relatively high fixed costs. Since the shale boom, collapsing dark spreads and dwindling capacity factors have cut deeply into coal's energy revenues – so much so that plants sometimes fail to cover fixed operating costs. Ongoing operating losses can drive plants to retire.
>
> Simply boosting output is not an option. Plants have reduced their capacity factors precisely because in many hours, fuel prices are higher than power prices. Running more would mean running at a loss. (p. 8)

Q: What does BNEF conclude about MidAmerican's plants?

A: Figure 10 reproduces the Iowa portion of BNEF's national map of coal-plant operating margins (before capital additions) for 2012–2017. The purple circles represent profitable plants, while grey circles were near breakeven, and the red circles lost money. Darker colors indicate stronger results in $/MW-day. The size of the circle is proportional to the capacity of the unit.

Figure 10: BNEF Map of Iowa Coal Plants[26]

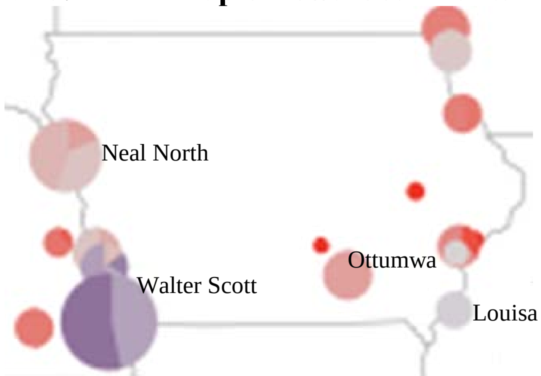


Table 26 provides BNEF's results for each of the MidAmerican units, for each year and cumulative for the period. The revenues for Walter Scott 3 and 4 substantially exceeded their fuel and O&M. The other units all lost money in five of the six years and overall.

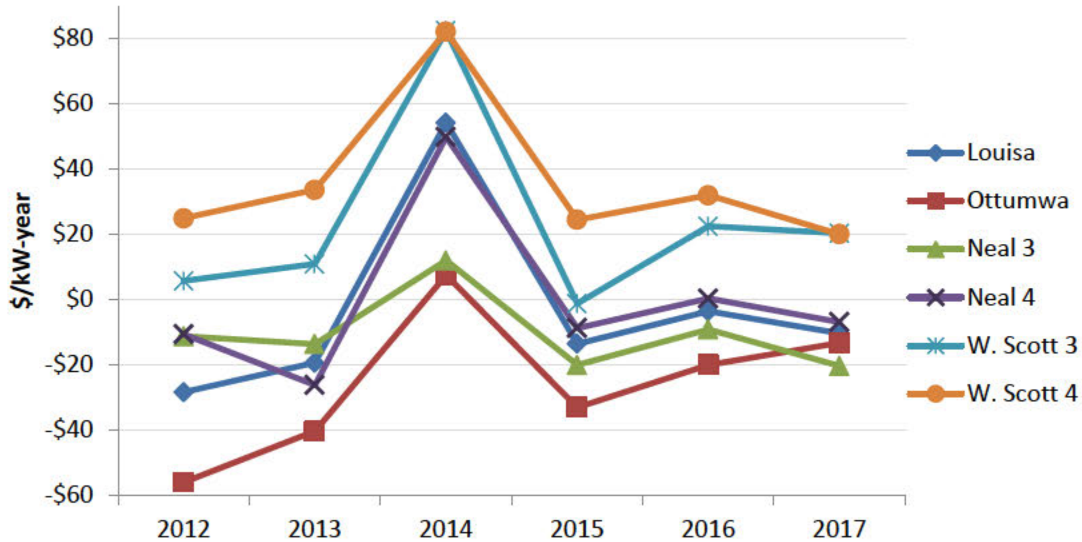
Table 26: BNEF Estimates of MidAmerican Unit Operating Profit ($kW)

	2012	2013	2014	2015	2016	2017	Total
Louisa	-$28.3	-$19.3	$54.2	-$13.5	-$3.5	-$10.3	-$20.7
Ottumwa	-$55.9	-$40.2	$7.5	-$32.9	-$19.9	-$13.2	-$154.7
Neal 3	-$11.2	-$13.6	$12.0	-$20.0	-$9.1	-$20.3	-$62.1
Neal 4	-$10.5	-$26.1	$49.9	-$8.7	$0.4	-$6.9	-$1.9
W. Scott 3	$5.8	$10.9	$82.4	-$1.2	$22.5	$20.3	$140.7
W. Scott 4	$25.0	$33.7	$82.1	$24.5	$32.0	$20.1	$217.4

Figure 11 presents the annual data from Table 26 in graphical format.

[26] Neal North includes the now-retired units 1 and 2. Neal 4 appears to be obscured by the Neal North circle.

Figure 11: Annual Unit Operating Profit, per BNEF



Since these are the annual profits without capital additions or overheads, these results understate the losses that MidAmerican's customers have experienced from Louisa, Ottumwa, and Neal. Including capital additions and overheads, the losses on those units would be even larger.

2. *The Brattle Study*

Q: What were the results of the Brattle study?

A: The Brattle Group study, attached as Exhibit PLC-4, used ABB's Velocity Suite data (the default data for PROMOD) to estimate the 2017 net margin for each domestic coal plant (as well as each nuclear plant).[27] Brattle does not identify the results for specific units, but does provide aggregate results, as summarized in Table 27.

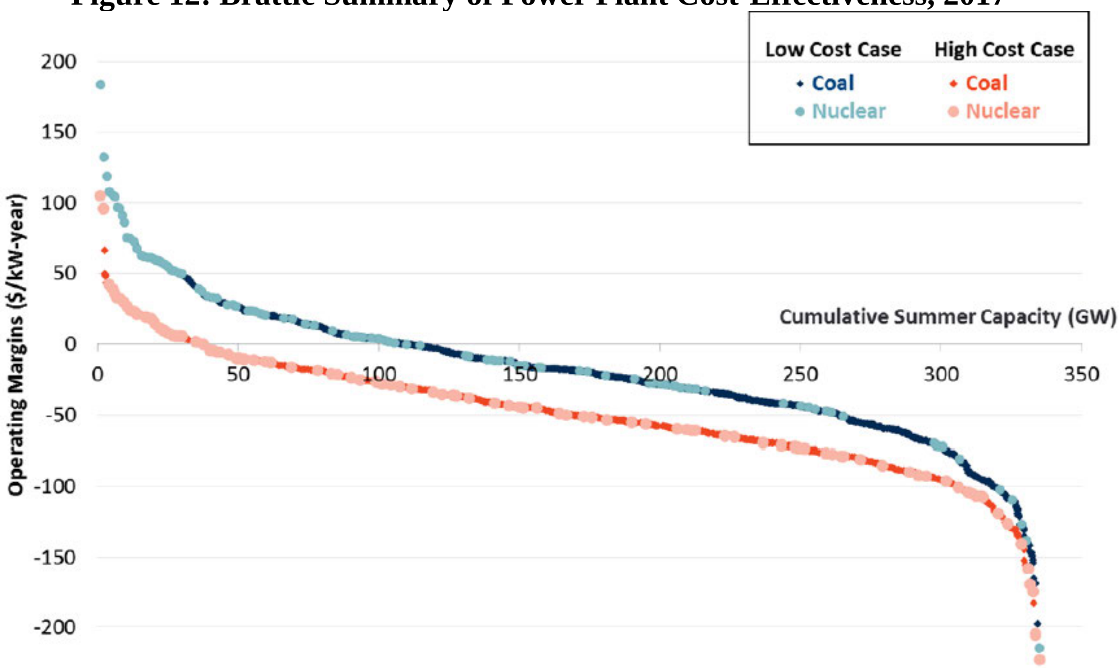
[27] The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum, Metin Celebi, et al, July 2018. Brattle reports that it excluded another 11.7 GW of coal units (averaging 37 MW per unit) were listed as having no generation and in most cases no cost data.

Table 27: Brattle Results for Coal Plant Economics, 2017

		Capacity with Revenue Shortfall			
		Gigawatts		Percentage of Total	
	Total Capacity (GW)	Low-Cost Case	High-Cost Case	Low-Cost Case	High-Cost Case
RTO	160.1	120.1	154.2	75%	96%
Non-RTO	75.7	65.3	69.5	86%	92%
Total	235.8	185.4	223.7	79%	95%

Brattle also plotted the distribution of plant profitability, as shown in Figure 12.

Figure 12: Brattle Summary of Power Plant Cost-Effectiveness, 2017



The dark data points, representing the coal plants, are sometimes obscured by the large light data points that Brattle used for the nuclear units.

Q: How do the costs of the coal units in the Brattle analysis compare to the costs of the MidAmerican coal units?

A: The average costs of the coal units in the Brattle analysis are listed in Table 28. Brattle used the unit-specific fuel and VOM costs from the ABB database, the generic FOM values from EPA that I discuss in Section III.B and the capital additions (CapEx) costs from EIA that I discuss in Section III.C.

Table 28: Brattle Average Coal Forward Costs ($/MWh)

	Low-Cost Case	High-Cost Case
Fuel Costs	$22.30	$22.30
VOM	$1.56	$4.91
FOM	$7.14	$8.51
Ongoing CapEx	$4.97	$4.97
Total	$35.97	$40.69

Compared to the MidAmerican costs summarized in Table 15, the low-costs Brattle average fuel costs and generic fixed O&M values are somewhat high, while the capital additions are reasonable (especially for Louisa, Ottumwa and Neal). On the other hand, the MidAmerican units face lower energy and capacity prices than most coal units. The MidAmerican units could be more economic than the average unit, but still unprofitable.

Q: Does this conclude your testimony?

A: Yes.

STATE OF MASSACHUSETTS)
) ss: Middlesex
COUNTY OF)

I, Paul L. Chernick, being first duly sworn on oath, state that I am the same Paul Chernick identified in the testimony being filed with this affidavit, that I have caused the testimony and exhibits to be prepared and am familiar with its contents, and that the testimony and exhibits is true and correct to the best of my knowledge and belief as of the date of this affidavit."

Paul L. Chernick

Subscribed and sworn to before me this 3rd day of August, 2018.

Notary Public