BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE AND CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR AN 88 MW SIMPLE CYCLE COMBUSTION TURBINE	))))))	**Case Nos. PU-19-306 and PU-19-307**

DIRECT TESTIMONY

OF

JAMES A HEIDELL

ON BEHALF OF

THE NORTH DAKOTA PUBLIC SERVICE COMMISSION ADVOCACY STAFF

February 19, 2020

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Prefiled Direct Testimony of James A. Heidell
Public Service Commission Advocacy Staff
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I. INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is James A. Heidell. I am a Director at PA Consulting Group, Inc. (PA). My business address is 1700 Lincoln Street, Suite 3550, Denver, CO 80203.

Q. On whose behalf are you filing this testimony?

A. I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public Service Commission (the Commission or NDPSC).

Q. Please summarize your education, professional experience, and qualifications?

A. I have worked in the energy industry for the past 35 years, primarily specializing in electricity and utilities. I have worked on issues related to resource planning, rates, analysis of electricity markets, and analysis of the economics of financial transactions for utilities and wholesale generation owners. My academic background includes a BSE in civil engineering from Tufts University, a MS in engineering economics from Stanford University, and an MBA in finance from the University of Washington. I am a Chartered Financial Analyst. My CV is provided in Exhibit JAH-1.

Q. Have you testified previously before the Commission or any other regulatory agency in this or any other proceeding?

A. Yes. I testified on behalf of Montana-Dakota Utilities in the matter of Montana-Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in the following dockets:

- Northern States Power Company's request for an Advanced Determination of Prudence for Dakota Range, Case Number PI-17-372;

- Northern States Power Company's request for an Advanced Determination of Prudence for 1,559 MW of Wind, Case Number PI-17-120;
- Otter Tail Power Company's Request for an ADP for the Astoria CT and Merricourt Wind Project, Case Nos. PU-17-140, PU17-141, and PU-17-143;
- Advance Prudence – Biomass Application for deferred accounting Northern States Power Company, Case Nos. PU-17-270, PU-17-271, and PU-17-322
- Northern States Power Company Resource Treatment Framework, Case Nos. PU-12-813 et al.; and
- Northern States Power Company request for an Advance Determination of Prudence for Dakota Range III, Case No. PU-18-430.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with my assessment of Montana-Dakota Utilities' (MDU or the Company) request for an Advance Determination of Prudence (ADP) and a Certificate of Public Convenience and Necessity (CPCN) to construct, own and operate Heskett 4 (the Project), an 88 MW frame type simple cycle combustion turbine (CT). MDU's modeling and analysis has identified Heskett 4 as a least cost resource used to meet customer peak demand requirements following the proposed retirement of the Heskett 1, Heskett 2, and Lewis & Clark 1 coal-fired generating units (the Three Coal Units).

Q. Would you please summarize the organization of your testimony?

A. Yes. I start with presenting my recommendations and findings, and then I discuss in detail the analysis I conducted to support my recommendations and findings. I then address additional factors considered. Finally, I propose conditions should the Commission approve the ADP. My testimony addresses the following issues:

- Whether the assumption including the load forecast, fuel prices, generation cost assumptions, and market electricity prices underlying the modeling of the coal plant retirements and the need for Heskett 4 are reasonable?
- Is MDU's retirement analysis / revenue requirement analysis that concludes that there would be ratepayer savings associated with the early retirement of the Three Coal Units and replacing them with Heskett 4 and other new resources reasonable?
- Assuming a need for a new capacity resource, is the construction of a frame combustion turbine the preferred resource?
- Assuming a need for a new CT, is the construction of Heskett 4 the preferred option?

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit JH-1: CV of James Heidell
- Exhibit JH-2: Multi Year Revenue Requirement Estimate

II. SUMMARY OF RECOMMENDATIONS

Q. What is your recommendation with regards to the Commission's approval of the Company's ADP and CPCN for Heskett 4?

A. I recommend that the Commission approve the ADP & CPCN for Heskett 4 subject to conditions on the maximum cost approved.

Q. If the Commission approves the Company's ADP and CPCN, what are your recommendations with regards to cost recovery?

A. The ADP should exclude any costs to upgrade the transmission system. One part of the Company's argument for construction of Heskett 4 is the assumption that the project will be able to retain the transmission rights from the retirement of Heskett 1 and 2 and hence the Project will not have the transmission upgrade costs of other projects.[1] Should MDU incur any transmission upgrade costs as a result of the installation of Heskett 4, the prudency of those costs should be determined in a future proceeding.

There should also be a limit on the total approved cost of $68.7M, excluding AFUDC. As I discuss in my testimony, while the Company conducted an RFP for energy and capacity resources in 2018, it did not conduct an RFP for capacity resources in order to demonstrate that the self-build option is the lower cost option. As such, I recommend the ADP be limited to a total cost of $68.7M. Should MDU incur additional total costs as a result of the installation of Heskett 4, prudency of those costs should be determined in a future proceeding.

III. SUMMARY OF FINDINGS

Q. Would you please provide a summary of the findings in your testimony that support your recommendations regarding the Commission's treatment of the ADP and CPCN?

1 Application page 5

A. After reviewing the Company's Application and supporting analyses including the Company's 2019 Integrated Resource Plan (IRP) filed with the Commission on July 1, 2019 (Case No. PU-19- 221), I found:

- The assumptions and inputs used in the Company's analyses regarding the operational cost of the coal plants were reasonable;
- The Company's revenue requirement analysis that concluded that there would be ratepayer savings associated with the early retirement of the Three Coal Units and replacing them with Heskett 4 and other new resources was generally reasonable, subject to certain issues I describe later in my testimony;
- Assuming a need for a new capacity resource, the construction / acquisition of a CT through ownership or a PPA is likely the preferred resource; and
- Assuming a need for a new CT, the construction of Heskett 4 is likely a lower cost option based upon the cost estimates put forth by the Company.

Q. Would you please provide a summary of the findings that support your recommendations regarding the economics of the early retirement of the coal plants?

A. I separately analyzed the retirement of the two Heskett units and Lewis & Clark Unit 1 and concluded the following.

- The ongoing non-fuel costs of operations exceeds the cost of replacing the coal plant capacity with the revenue requirement associated with constructing a low cost combustion turbine; and
- There are expected cost savings associated with replacing the energy generated by the coal plants with either market purchases or renewable resources.

IV. OVERVIEW OF MONTANA DAKOTA'S PROPOSAL TO CONSTRUCT A SIMPLE CYCLE COMBUSTION TURBINE

Q. Would you please provide an overview of the Company's Application for the ADP and CPCN?

A. MDU has requested an ADP and a CPCN to construct Heskett 4, an 88 MW CT near Mandan, North Dakota. The proposed unit would be located adjacent to the existing Heskett 3 CT and take advantage of the existing transmission and natural gas pipeline capacity available at the site. MDU has calculated the total cost of constructing Heskett 4 is \$68.7M and \$73M including AFUDC. The North Dakota share is approximately \$58.1M. The estimated cost is approximately 45% less than what Burns & McDonnell estimated for greenfield construction of a comparable turbine.[2]

Q. Is the Company's construction cost estimate for Heskett 4 based upon detailed design and firm bids for equipment?

A. No, the construction cost is an initial estimate based upon information provided by Burns & McDonnell and the Company's experience with Heskett 3.

Q. What is the proposed in-service date for Heskett 4?

A. The proposed in-service date is March 2023 with the start of construction in March 2022. The start of construction is linked to the end of the current Heskett coal contracts; the in-service date is subsequent to the retirement of the two Heskett coal units in order to utilize existing transmission rights and avoid transmission upgrades as well as for the air permit to take advantage of the emission reductions associated with the coal plant retirements.

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2 2019 IRP Technology Assessment, Montana-Dakota Utilities Co., p 52. Cost of \$124M without AFUDC and \$132M with AFUDC.

Q. Is MDU requesting approval to retire Lewis & Clark Unit 1, and Heskett Units 1 and 2 in this proceeding?

A. No, MDU has asked for deferred accounting treatment to recover the costs of Lewis & Clark 1, Heskett 1, and Heskett 2 (the Three Coal Units) in a separate docket. However, the Company's analysis for Heskett 4 is predicated on the need to meet peak demand requirements driven by the early retirement of the Three Coal Units. While the Company conducted the retirement analysis as part of its 2019 IRP, it is my understanding that the Commission neither formally reviewed, nor approved the retirement analysis. It is my recommendation that because the early coal plant retirements create the need for new capacity, the coal plant retirements must be evaluated in this proceeding as the foundation for approval of the requested ADP and CPCN.

V. COAL PLANT RETIREMENT ANALYSIS

Q. Please provide an overview of MDU's coal plant retirement analysis?

A. In the Company's 2019 IRP, the retirement of the Three Coal Units was analyzed using the EGEAS resource planning model. The Company modeled retirement of the Three Coal Units in 2021, 2024, and 2029. The Company also tested alternative new resources under scenarios predicated on the retirement of the Three Coal Units in 2021 and constructing Heskett 4 in 2022. Additional scenarios were modeled including scenarios to evaluate the impacts of potential high and low natural gas prices and high and low wholesale electricity prices. Based upon these analyses, the Company concluded that the early retirement of the Three Coal Units was the most cost-effective option.

Q. What are some of the consequences of early retirement of the Three Coal Units?

A. The key consequences include:

- The need for replacement capacity for the 144 MW of retired coal capacity and the associated request for an ADP and CPCN for Heskett 4, the matter in this proceeding;
- A request for recovery of undepreciated plant balances, decommissioning costs, and other retirement costs associated with the retired coal units, a matter in a parallel proceeding (Docket No. PU-19-317); and
- The potential need for a replacement energy resource as opposed to relying upon MISO market purchases; a matter that has not yet been addressed in a filed docket.

In addition to the potential cost savings for MDU's customers, there are other implications including impacts on jobs and generation resource diversity.

Q. How do these implications impact your recommendation regarding the ADP and CPCN?

A. My recommendations not only considers whether Heskett 4 is the lowest cost option for new capacity, but also whether the early retirement of the Three Coal Units - which create the need for replacement capacity and energy - is the lowest cost solution, including the cost recovery associated with the early retirements.

Q. Conceptually, how did you think about the economics of the early retirement analysis and replacement of resources?

A. Because the Company is seeking recovery of the $70.0 million of undepreciated asset balance, decommissioning costs and employee retention costs of the Three Coal Units, the customers are expected to pay those costs regardless of whether the assets are retired early. Of course, early retirement can accelerate the payment of those costs. While there may be a timing difference, I frame the analysis as whether there are customer savings associated with both a) procuring new generation capacity including fixed operating costs, variable operating costs, return of capital, and return on capital and b) procuring additional energy or continuing to pay the fixed and variable operating costs of the coal units and supply energy from those units assuming that any new coal contract will also have minimum volume requirements . While the Company's application and analysis is structured around the retirement of the Three Coal Units, I considered the economics of the retirement of the two Heskett units separately from Lewis & Clark Unit 1.

Q. How did you evaluate the reasonableness of MDU's retirement analysis that creates the need for replacement capacity?

A. My evaluation is primarily based upon a review of the EGEAS modeling prepared by the Company in its 2019 IRP, supplemental data requests, and the associated revenue requirement analysis.

Q. How did you evaluate the Company's EGEAS modeling?

A. My evaluation considered the following issues:

- Whether the modeling approach used by the Company was reasonable;
- Whether the key inputs used in the modeling were reasonable; and
- Whether the scenarios considered by the Company were reasonably comprehensive.

Q. Was the modeling approach used by the Company reasonable?

A. Yes. The Electric Generation Expansion Analysis System (EGEAS) is a resource expansion modeling tool developed by the Electric Power Research Institute. It uses a load duration curve modeling approach that simplifies the task of modeling alternative portfolios. There are limitations with a load duration curve model including the modeling of generation curtailment and capturing the capacity factor of peaking units. As with any resource expansion model, the reasonableness of the results is dependent on the reasonableness of the inputs.

Q. What EGEAS inputs did you review as part of your retirement analysis evaluation?

A. I reviewed the load forecast, fuel cost assumptions, mix of generation options, generation operating cost assumptions, and wholesale electricity price assumptions.

Q. What is the source of the load forecast?

A. The energy sales and peak demand forecasts were developed by MDU and are inputs into the retirement analysis and those are both components of the 2019 IRP.

Q. Did you review the methodology for the load forecast?

A. Yes, the Company uses an econometric forecasting approach for both energy and peak demand. The energy forecasts were developed for five different sectors; residential, small commercial & industrial, large commercial & industrial, lighting, and miscellaneous. The sector level energy forecasts are developed separately for North Dakota, South Dakota, and Montana. The large commercial and industrial forecast incorporates customer specific sales forecasts for some of the largest load customers. Both the econometric approach and use of customer specific forecasts for large loads is frequently used in utility sales forecasting. The econometric demand forecast is based upon the total annual sales forecast and incorporates cooling degree days and peak temperature.

Q. What is the Company's forecast for energy and peak demand growth rates?

A. A summary of the Company's forecast is shown below in ***Table 1***. The table reports the system sales forecast rather than the North Dakota sales forecast since MDU plans for, and operates, power production and delivery as an integrated system. The decline in street lighting sales, although a small percentage of sales, is attributed to conversion of streetlighting to LEDs. The following table shows summer peak demand since both the Company and MISO are summer peaking and the MISO resource requirements are based upon the summer peak demand.

Table 1: Sales and Peak Demand Growth Rates

Time Period	Residential	Small C&I	Large C&I	Street Lighting	Misc.	Total Sales	Summer Peak
10 Yr Historical	2.70%	4.79%	1.58%	-1.59%	2.13%	2.63%	1.85%
10 Yr Forecast (2019 - 2029)	0.44%	2.16%	2.42%	-5.49%	1.03%	1.66%	1.38%
19 Yr Forecast (2019 - 2038)	0.38%	2.01%	1.74%	-2.93%	0.94%	1.36%	1.18%

Q. Did the Company develop alternative load growth scenarios?

A. Yes, the Company developed low and high load growth scenarios. I focused on the low load growth scenario to evaluate the need for new capacity if load growth slows more than the base forecast. A summary of the growth rates associated with the low load growth scenario is shown in ***Table 2***.

Table 2: Sales and Peak Demand Growth Rates for Low Growth Case

Time Period	Low Sales Forecast	Low Demand Forecast
10 Yr Forecast (2019 - 2029)	0.50%	0.21%
19 Yr Forecast (2019 - 2038)	0.50%	0.32%

Q. Do you consider the assumed growth rates reasonable for the purposes of evaluating the need for new capacity?

A. Yes, I consider growth rates between the low and base case as reasonable for the purposes of identifying the need for new capacity. However, it should be recognized that the need for new capacity is not being justified on the basis of load growth, but by the current reserve margin and shortfall created by the proposed retirement of the Three Coal Plants.

Q. If MDU proceeds with early retirement of the Three Coal Units how much incremental capacity will it need?

A. The 2019 IRP identifies a 49.4 MW surplus of zonal resource credits (ZRCs) in 2021 prior to the planned retirement of the coal units. In 2022 the Company identifies a deficit of 92 MW of ZRCs following the proposed retirements. The deficit grows over time due to load growth assuming no new resources are added.[3]

Q. Did you evaluate the fuel cost forecasts?

A. Yes, I reviewed the base case coal cost forecast as well as the base, low, and high natural gas forecasts. MDU's coal price forecasts are developed internally at MDU based on projecting the current coal contracts pricing. MDU's base case natural gas price forecasts were developed using a combination of:

- forward index prices at Henry Hub (which is the foremost trading location throughout the United States);
- MDU's commodity portfolio which blends fixed-price and index-priced fuel purchases with existing and in-ground gas storage inventories;
- historic basis differentials between the Ventura Hub and MDU's delivered gas price for each plant; and
- the Ventura Hub forecast received by MDU's Gas Supply department.

Q. Does the natural gas forecast have a significant impact on the economics of Heskett 4?

A. No. The optimal supply plans resulting from the EGEAS analysis are essentially to replace the coal plants with a CT for capacity and to add market energy resources for

3 2019 IRP Volume 1 Table 4-1.

energy. The EGEAS forecast capacity factor for Heskett 4 over the 2022 – 2037 period varies. However, it never exceeds 1.15%, and in most years is below 1%. While the Company's revenue requirement analysis assumes a higher capacity factor, 3.6%, natural gas costs are a small part of the annual revenue requirement.

Q. Is the natural gas forecast an important consideration?

A. Yes, the natural gas price forecast will impact the economics of whether to construct a combined cycle plant for capacity and energy versus the CT for capacity and market purchases / renewable energy to replace the energy provided by the coal units. The natural gas outlook will impact the cost of replacement energy purchased from MISO. In 2018, natural gas was the system marginal fuel in MISO approximately 53% of the time.[4]

Q. Do you consider the Company's natural gas cost forecast reasonable?

A. While I believe the natural gas price forecasts are somewhat low, they are not unreasonable. I compared MDU's base, high, and low natural gas price forecasts to PA's price forecast, developed in PA's fundamental gas market modeling using the Gas Pipeline Competition Model (GPCM). The results are shown below in ***Figure 1***.

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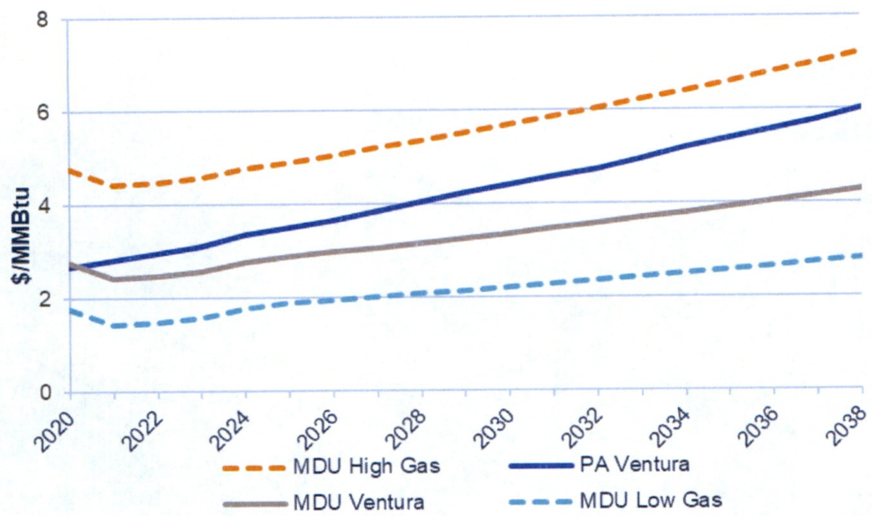
4 2018 State of the Market Report for the MISO Electricity Markets, Potomac Economics, June 2019, p.5.

Figure 1: Ventura Hub Natural Gas Pricing



Q. How does MDU's natural gas price forecast impact its retirement analysis?

A. MISO's market prices are driven by the cost of natural gas approximately 50% of the time, with coal generators driving the market prices much of the remaining 50% of the time. Because MDU's analysis projects the proposed CT, Heskett 4, to have very low utilization, the natural gas price forecast doesn't materially impact the costs of Heskett 4 generation. The Company's retirement analysis for the Three Coal Units was impacted primarily by its market price assumptions compared to the operating costs of the Three Coal Units.

Q. How does MDU incorporate wholesale prices in its resource planning analysis?

A. The Company allowed the EGEAS model to rely upon market purchases up to 200 MW in an hour. This appears sufficient to allow the model to select market purchases to replace the energy generated by the proposed retirement of the Three Coal Units. However, the combination of the forecast of wholesale electricity prices and the designation of coal units as "must run" may result in the dispatching of Company coal resources with higher variable costs than the projected market prices.

Q. How does MDU incorporate wholesale prices in its revenue requirement analysis?

A. The Company's revenue requirement analysis presented in Exhibit TRJ_1is limited to a one-year horizon (2023) and the analysis assumes the replacement energy from the coal plants is from wholesale market purchases.[5]

Q. How did MDU develop its forecast of wholesale electricity prices?

A. For the years 2020 and beyond, the Company applied a three percent annual escalation to the 2019 average monthly market price. The 2019 average market prices for March – December 2019 were calculated as a simple average of the monthly price for prior three years.[6]

Q. Do you consider MDU's wholesale price forecast to be a reasonable assumption?

A. As with the natural gas price forecast, I find the Company's market price forecast to be lower than PA's market view. (see Figure 2) However, the Company's high market prices, plus $10 is better aligned in the long term. Furthermore, I expect the Company might be able to secure additional wind resources at a lower cost than the market price and also be able to use wind as an alternative to bearing market price risk.

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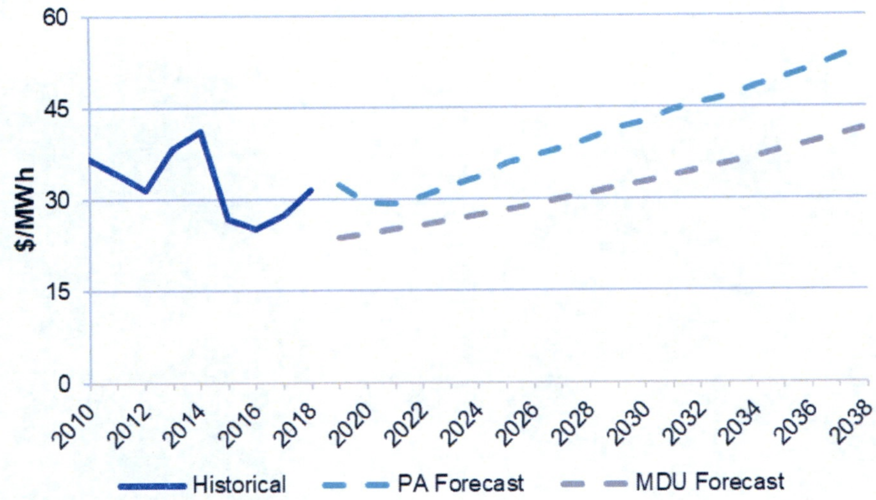
5 See Response No. 4-1 Attachment A.xlsx.
6 Company Response 2-2 2018-2027 Forecast Summary.xlsx.

Figure 2: MISO Energy Market Prices



Q. How does MDU's market price forecast price impact the retirement analysis?

A. The Company's analysis evaluated the future dispatch and associated market revenues of the Three Coal Units compared to their operating costs and did the same calculation assuming the units were retired and replaced by Heskett 4 and market energy purchases. To the extent the Company's forecast of market prices are low, the analysis will understate the value of the Three Coal Units by understating their dispatch and associated market revenues. However, I concluded that even were the Company to use PA's (higher) market price forecast, the Heskett coal units will still have higher dispatch costs than the market and thus would see very low utilization and associated market revenues, resulting in very low or potentially negative earnings when including their fixed operating costs.

Q. Did you review the operating cost assumptions?

A. Yes, I reviewed both the generic assumptions for the new units as well as the assumptions for the coal plants targeted for early retirement. The coal plant operating cost assumptions are critical to the retirement analysis. In addition, the assumptions for the generic new units along with fuel prices are critical in the analysis both with regards to whether early retirement of the coal units is cost effective and what resources should replace the coal units.

Q. What are MDU's assumptions with regard to the coal plant operating costs?

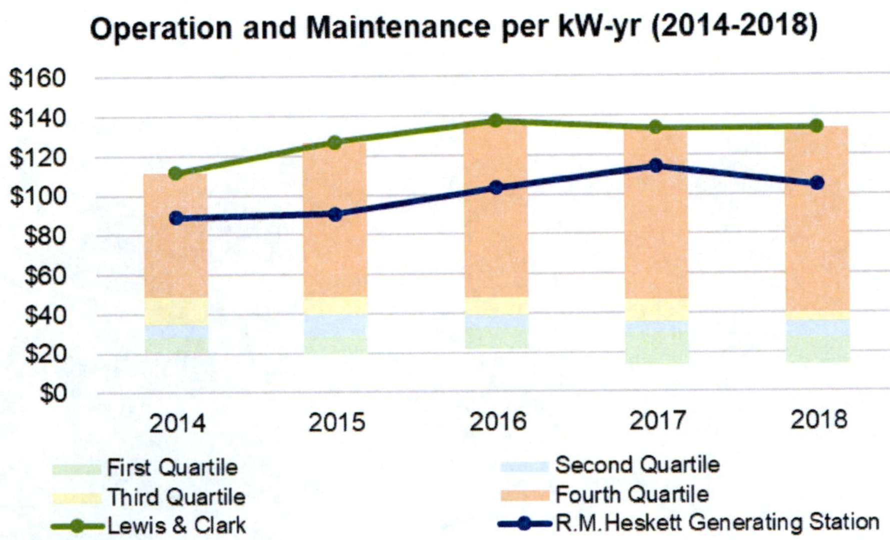
A. MDU assumes that the Heskett Units 1 & 2 will have non-fuel operating expenses in the 9 to 11 million dollar range annually through 2025; MDU assumes the Lewis and Clark Unit 1 will have operating expenses in the 6 to 7 million dollar range through 2025. MDU's projections are based on escalating 2018 actual expenses, using 3.0 percent escalation for labor expenses and 2.6 percent escalation for non-labor expenses. The Company also made additional adjustments for an expected major overhaul outage on the Heskett units.

Q. Did you review the historical operating costs?

A. Yes. In addition to data provided by the Company in its Application, I reviewed the Three Coal Plants' historical operating expenses reported in the Company's Federal Energy Regulatory Commission (FERC) filings.

I conducted a benchmarking analysis of the Three Coal Plants' historical fixed and non-fuel variable operating costs by comparing them to those of a group of similar coal plants. For the benchmarking analysis, I chose a peer group of coal plants operating in the MISO market with similar age and size characteristics. I found that the Three Coal Plants' historical operating costs were the highest of their peer group. ***Figure*** provides the results of the benchmarking analysis.

Figure 3: Operation and Maintenance by Peer Group Quartile



Source: S&P Global Market Intelligence

Q. Do you conclude that the coal plant operating costs are reasonable?

A. Based upon my review of historical costs and benchmarks, I conclude the historical operating costs for the Three Coal Plants are the highest of their peer group, and the operating cost projections used in the retirement analysis were based on these historical operating costs. However, I also conclude that due to the Three Coal Plants' dispatch costs, which are largely composed of fuel costs, they would be unlikely to earn enough revenue in the MISO markets to offset their fixed operating costs even if their fixed operating costs were significantly lower.

Q. Would you please provide a summary of the modeling scenarios developed by the Company?

A. Yes, the Company ran scenarios with base / high / low gas price forecasts, base / low growth / high growth load forecasts, base / low / base +5$ / base + 10$ energy prices and a high CT cost scenario to identify the least cost expansion plan. Most of the runs had the same system expansion solution:

- Adding Heskett 4, 54 MW of wind, and 10 MW of purchased power in 2022;
- Adding 100 MW of solar in 2025; and
- Adding a 110 MW combined cycle plant in 2025.

The high CT cost scenario increased the cost of the CTs by 20%.

The Company then ran two alternative scenarios using the base case expansion plan to test the economics of retiring the three coal plants by the end of 2021, end of 2025, and 2029.

Q. Would you expect the Three Coal Units to economically dispatch post the current proposed retirement date of 2022?

A. No, they would not be likely be economically dispatched based upon the Company's assumptions related to the variable O&M plus fuel costs and the assumptions regarding MISO wholesale market prices. As shown in the ***Table 3***, the coal plants would not economically dispatch except in any periods of high prices that are not reflected in the on- and off-peak price estimates.

Table 3: Estimated 2023 Dispatch Cost[7]

Resource	Variable O&M + Fuel / MISO Price ($/MWH)	High Market Price Case	PA Market Price Forecast
Heskett 1	$89.4		
Heskett 2	$54.3		
Lewis & Clark 1	$39.1		
MISO Off-Peak	$24.7	$25.7	23.76
MISO On-Peak	$28.4	$38.4	32.93

Q. Are the modeling scenarios reasonably comprehensive?

A. The scenarios are reasonably comprehensive with regards to resource options available. As with any resource modeling, the results are driven by the assumptions. The selection of the Heskett CT versus a greenfield CT or the aeroderivative turbine options is to be expected as a result of the significantly lower cost assumed for Heskett 4. The heat rate advantage of the aeroderivatives is not sufficient to overcome the first cost premium and the very low capacity factor of the CT.

VI. EVALUATION OF THE REVENUE REQUIREMENTS OF MONTANA-DAKOTA'S RETIREMENT ANALYSIS

Q. Would you please provide a summary of your review of the retirement analysis?

A. Yes, I reviewed the revenue requirement analysis prepared by MDU in its 2019 IRP in addition to the previously mentioned review of the EGEAS modeling.

Q. How did you analyze the revenue requirement analysis?

A. In my analysis I assumed the undepreciated plant balances for the Three Coal Units would be recovered regardless of when the plants are retired. Therefore, I looked at the integrated system's fuel and O&M costs assuming the Three Coal Plants were not retired

7 Costs are based upon Montana-Dakota's response to Advocacy Staff Response 2.2 BASE_29 Output

early compared to the integrated system's full cost (including return on and of capital) of the replacement energy and capacity.

Q. What did MDU assume for replacement energy?

A. The EGEAS modeling results primarily use MISO market purchases to substitute for the electricity that would otherwise be produced from the retired coal plants. The renewable energy is assumed to cost $24.64/MWH in 2022.[8]

Q. What did MDU assume for replacement capacity cost?

A. The Company assumed the coal unit replacement capacity would come from a combination of Heskett 4 and 60 MW of market capacity purchases in 2023 at $4/kW month. The EGEAS modeling assumes additional replacement capacity in 2025 from a jointly owned combined cycle plant. However, the Company's IRP calls for a future Request for Proposal for capacity and energy resources prior to developing the combined cycle plant.

Q. Would you please summarize the Company's savings analysis?

A. The Company calculated a first year, 2023, integrated system savings of approximately $20M associated with the retirement of the Three Coal Plants, construction of Heskett 4, and the purchase of replacement energy and capacity. The North Dakota share of those savings would be approximately 75% of the system savings.[9] The Company also calculated system wide total construction cost savings (excluding AFUDC) of $55.6M associated with constructing Heskett 4 versus a comparable greenfield single cycle gas turbine (SCGT).[10]

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8 MDU Response No. 2-2 Base 21 output.
9 Exhibit No.__(TRJ-1)
10 MDU Application p 8.

Q. Do you review the Company's savings estimate?

A. Yes, I reviewed the savings estimate and concluded the savings were about half of what the Company estimated. I attribute the difference in savings estimates to: 1) assumptions about the timing or recovery of the remaining plant balances associated with the retired coal plants and 2) estimates of the power cost savings.

Q. Would you please explain the difference in savings estimates associated with the return on and off the Three Coal Plants?

A. Yes, the Company is requesting a fifteen year amortization of the remaining plant balances of the Three Coal Plants along with a return on the unamortized plant balances. Regardless of whether the Three Coal Plants are retired, MDU's request is for customers to pay off the net plant balances through either depreciation or amortization charges and provide the Company with an annual return on either the net plant balance or unamortized regulatory assets associated with the remaining plant balances. Depending on how the plant balances are recovered in the retirement or no retirement scenarios there may be differences in the timing of the recovery, but on a net present value basis the total cost should be the same. Specifically, in the analysis provided by the Company the revenue requirement associated with the coal plants staying on-line is based upon annual depreciation expense and return on rate base, and that annual amount decreases over time due to the declining rate base. I extended the Company's depreciation schedule assuming no new plant additions after 2025 so the remaining plant balance for Heskett is recovered by the end of 2030. That is eight years after the proposed 2022 retirement date. However, in the Company's retirement calculation the Company assumes a recovery of the remaining plant balance over 15 years after the proposed 2022 retirement plant.

Furthermore, the recovery in the retirement analysis assumes a constant annual payment for each of the 15 years. The net impact is that the Company's analysis creates approximately $6M of savings in 2023 in the retirement scenario simply by extending the recovery of the plant balances over a longer period of time.

Q. Would you please describe the differences in Power Cost Savings?

A. Yes, the Company provided hard coded values for fuel and purchase power savings in response to Advocacy Staff Data Request 4-1. For reasons elaborated on below, I based the fuel and purchased power savings on the Company's response to Advocacy Staff Data Request 2-2.[11] The different estimates may be based on different modeling assumptions, but in either case there are inevitable forecast errors. The difference in fuel and purchased power costs between the two data responses is approximately $2.4M in 2023.

Q. What is the net impact of the two adjustments?

A. The next impact is that the savings estimates are approximately $8.5M less than what the Company provided in Mr. Jacobson's Exhibit TRJ_1.

Q. Do you anticipate that there will be annual savings?

A. Yes, in Exhibit JAH-2 I estimate annual savings based upon removal of the impacts of the timing differences in recovery of the net plant balances and using the AGEIS modeling results provided by the Company. In addition, I tested the annual savings with different assumptions regarding MISO wholesale energy prices. The results of the analysis are summarized in ***Table 4*** with supporting detail provided in Exhibit JAH_2. Note that the results have been expressed as North Dakota's share of the system savings based upon

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11 The fuel and purchase power costs are based upon the EGEAS Base 21 (with retirement) and Base 29 (retirement in 2028) model runs.

assuming 72.5% of the savings will be allocated to North Dakota.[12] I have also removed the decommissioning costs as a cost associated with early retirement because I consider that a timing difference. Customers will have to pay decommissioning costs regardless of whether the plants are retired in 2022, 2028, or some other date.

Table 4: Annual Savings Under Alternative Scenarios

Case	Scenario	Units	2023	2024	2025	2026	2027	2028	2029
1	PA Analysis of MDU Base Case								
	North Dakota Savings	$(000)	9,071	9,276	9,738	10,596	11,243	11,658	11,760
	Average Rate Savings	Cents / kWH	0.39	0.40	0.41	0.44	0.46	0.47	0.47
2	PA Analysis of MDU High Market Price Case								
	North Dakota Savings	$(000)	7,194	7,323	7,598	8,628	9,128	9,404	9,642
	Average Rate Reduction	Cents / kWH	0.31	0.31	0.32	0.36	0.37	0.38	0.39
3	PA MISO Market Price Case								
	North Dakota Savings	$(000)	8,024	7,817	7,949	8,894	9,255	9,419	9,436
	Average Rate Reduction	Cents / kWH	0.35	0.33	0.34	0.37	0.38	0.38	0.38
4	MDU Analysis								
	North Dakota Savings	$(000)	15,048	15,220	15,542				
	Average Rate Reduction	Cents / kWH	0.65	0.65	0.66				

Q. Why did you test the savings with different MISO market price assumptions?

A. The Company's analysis assumes most of the generation from the retired coal plants is supplied from on-peak MISO market purchases. While MISO prices could be lower or higher than the Company's base case assumption, I evaluated the downside of higher prices. I considered two alternative price forecasts: the high scenario used by the Company ($10 / MWH above the base case) and a PA price forecast. These results are also summarized in Table 4 and Exhibit JAH_1.

Q. Will early retirement of the Three Coal Plants result in savings under the two higher price MISO market forecasts?

12 The 72.5% estimate is based upon averaging an approximately plant allocation factor of 70% and approximate energy allocation factor of 75%

A. Yes, in the higher MISO price forecasts there are still anticipated savings for customers.

Q. Are you proposing any changes to the Company's estimated savings?

A. Yes, I proposed that the savings on recovery of the net plant be removed from the analysis and the Commission use the range of results presented in the three PA scenarios in Table 4 as indicative of the level of savings likely to be realized by North Dakota customers.

VII. REPLACEMENT RESOURCES FOR THE RETIRED COAL PLANTS

Q. How does the Company propose to replace the capacity and energy currently supplied by the Three Coal Units?

A. The Company is seeking approval to replace 88 MW of the 146 MW of retired coal capacity with the Heskett 4 CT. However, the Company will need to replace both the remaining capacity and the energy. In the EGEAS model base case which included the retirements, the model selected a combination of wind generation, solar PV, a combined cycle combustion turbine, and market purchases to supplement the Heskett 4 resource. While there are a range of potential replacement options, this type of decision in today's resource planning environment typically is a choice between a combination of renewable energy and peaking dispatchable capacity or efficient, gas-fired combined cycle capacity.

Q. Did the Company consider a range of dispatchable resources as potential replacements for the Three Coal Units?

A. Yes, the Company's expansion plan modeling incorporated multiple types of new resources including a gas-fired combined cycle and aeroderivative combustion turbines. The Company's analysis did not select the combined cycle as the low cost option in 2023 although the model incorporates 110 MW of new CC in 2025. Again, the resource selection of Heskett 4 is not surprising given the combination of the assumptions of the low cost of Heskett 4 and the forecast of low MISO market prices.

VIII. MONTANA-DAKOTA'S DECISION TO PURSUE THE SELF-BUILD OPTION

Q. Did the Company conduct a competitive bidding process to identify the lowest cost option for acquiring new peaking capacity?

A. No, through its consultant Burns & McDonnell, the Company conducted an analysis of the anticipated cost of constructing Heskett 4 versus the expected cost of a new greenfield construction. The expected cost of new greenfield construction was developed as part of the 2019 IRP. The expected cost of constructing Heskett 4 is 68.7 Million ($878/kW summer) versus the IRP estimates for a greenfield of $124.3 Million ($1,588/kW summer).[13]

Q. What is the basis for the estimated cost savings compared to the greenfield option?

A. The Company assumes savings in project capital costs and Owner's cost. A summary of the sources of the assumed savings are shown in Table 5.[14]

13 Application p 8.
14 MDU Application Exhibit 1, page 53.

Table 5: MDU Assumed Brownfield SCGT Cost Savings[15]

Cost Item	Brownfield Savings ($M)
Project Capital Costs	$(4)
Transmission Interconnection	$(14.5)
Network Upgrades	$(11)
Gas Interconnection	$(7.4)
Other Owner's Cost	$(18.7)
Total	$(55.6)

Q. Did you evaluate the reasonableness of the greenfield costs assumed in the IRP?

A. Yes, I conducted a benchmarking analysis of the Company's greenfield cost assumptions versus those assumed in other regional utilities' IRPs. While I acknowledge that the other IRPs do not reflect the specifics of the Montana Dakota system, I note that the Company's IRP greenfield estimate is higher than the assumptions included in the other IRPs I reviewed as illustrated in Table 6. However, the larger CT's have economies of scale that MDU would not have with a sub 100 MW CT.

Table 6: Comparison of CT Prices

Company	Description	Capital Cost ($/kW)
Basin Electric	25-150 MW CT	$750-1000
Idaho Power Company	170 MW CT	$1009
PacifiCorp	233 MW CT	$704
Puget Sound Energy	237 MW CT	$686
Xcel Energy	232 MW CT	$495

15 Based upon Burns McDonnel cost estimates, MDU Application Exhibit 1 page 52.

Q. Do the other IRP estimates suggest that the Company's proposal to construct Heskett 4 is not the lower cost approach?

A. No, my conclusion is the brownfield cost advantages, including the use of existing transmission capacity and existing natural gas pipeline infrastructure, will likely result in savings over greenfield construction. However, in a competitive bidding process, the expected brownfield savings would likely be less than the $55.6M projected by the Company.

Q. Are there other combined cycle or combustion turbines in the region that the Company could potentially purchase versus pursuing new construction?

A. No, I was not able to identify any. MISO's Zone 1 does not include many resources that are not utility owned or contracted to a utility. These resources are commonly referred to as "merchant plants", and in some areas of the United States, utilities are able to purchase these resources from their non-utility owners rather than pursue new construction. However, in MISO's Zone 1 there are few other options.

Q. What are your conclusions regarding the proposed plan for construction of a CT and specifically Heskett 4?

A. My conclusion is that construction of the combustion turbine that will serve primarily as a capacity resource and an associated procurement of replacement energy, likely renewable energy, is a reasonable replacement strategy versus other replacement options for capacity and energy. Furthermore, the proposed cost for construction of Heskett 4 is likely to result in cost savings compared to a greenfield CT developed by either MDU, or through a competitive procurement process.

IX. OTHER IMPACTS

Q. How does the retirement of the Three Coal Plants impact the Company's resource mix?

A. Table 7 illustrates the expected change in energy mix in 2025 based upon the Company's modeling. The energy mix and simulations incorporate the IRP assumption of new wind and solar resources added in 2022 and 2023. However, because both simulations include the new wind and solar resources, it appears the only change between the two cases is to test the relative savings of retiring the coal plants earlier. The resource expansion modeling included the same amount of new wind and solar resources in both cases. Consequently, the model essentially replaces the lost coal plant generation with MISO market purchases. My concern is that while the analysis shows the savings of retirement versus market purchases, it is not necessarily a test of the least cost resource additions. Further, it is not clear the Company intends to rely on the MISO market for 33% of its energy purchases, although the Company notes MISO supplied 27% of its energy purchases in 2019.[16]

Table 7: 2025 Generation Mix[17]

Resource	No Coal Retirements	Retirements / Heskett 4
Coal	44%	36%
Gas	1%	1%
Renewable	30%	30%
Market	25%	33%

Q. Do you have any concerns with the proposed shift of the energy mix from coal to renewables or market purchases?

16 2019 IRP Volume 1 Figure 6-6.

17 Analysis based upon MDU Response to Advocacy Staff 2-2 and the scenarios BASE21 Output and BASE29 Output.

A. In this instance I am not concerned. The retirement of coal units, especially older and smaller coal units is part of a national trend driven by low cost energy from wind and solar as well as low cost natural gas. The proposal to construct Heskett 4 provides both capacity and a back-up thermal resource that offsets some of the potential concerns associated with maintaining system reliability with increasing amounts of non-dispatchable intermittent renewable resources.

Q. Do you have any other concerns with the Company's base case scenario?

A. Yes, while this proceeding is not about the IRP and I agree that there are rate benefits with the coal retirements, I have a concern about the quality of the analysis used in part to support the retirement analysis. It is not intuitive why the combined cycle unit is added in 2025 since it does not operate above a 1% capacity factor until 2034 when the capacity factor increases to 6.44%. Given the higher installed costs relative to combustion turbines, combined cycle units typically require higher utilization and energy revenues to justify the installed cost.

Q. Are there non-customer impacts to the closure of the coal plants?

A. Yes. The Company discussed potential impacts for more than 70 employees of the Three Coal Units. Approximately 10 employees will be retained to operate the two natural gas fired units at Heskett, and a plan is in place that will maintain staff until the plant retirements, when the Company will offer training for employees who wish to fill open positions elsewhere within the Company.[18]

In addition, there are potential impacts to the Westmoreland lignite coal mines located in North Dakota and Montana. In North Dakota, Westmoreland operates the Beulah Mine

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18 2019 IRP P 51

located just south of the town of Beulah. The Beulah Mine provides lignite coal to Heskett 1 and Heskett 2 with a minimum purchase requirement of 400,000 tons per year. The contract expires December 31, 2021.[19] The Beulah Mine produces 500,000 tons of lignite coal per year, and the retirement or non-renewal of Heskett 1 and Heskett 2 could potentially lead to the closure of the mine.

Westmoreland also operates the Savage Mine just west of Savage, Montana, which has supplied Lewis & Clark with coal since 1958. The mine also supplies a nearby sugar beet processing facility operated by Sidney Sugars. The mine produces roughly 350,000 tons of coal per year and has a contract with the Company to supply Lewis & Clark 1 with between 250,000 and 300,000 tons of coal per year that expires January 31, 2020.[20] The retirement of Lewis & Clark 1, or the non-renewal of the supply contract, would have material and adverse consequences on operations at the Savage Mine, which could lead to the closure of the mine. It has also been suggested by the Superintendent of Savage Schools that the closure of the mine could lead to the school system realizing a material deduction in associated tax revenue.

X. RECOMMENDED CONDITIONS ON APPROVAL OF THE ADP

Q. Are you recommending that the Commission impose conditions on any approval of the ADP?

A. Yes. The Company has made its case for constructing Heskett 4 versus a greenfield development based upon cost savings that include taking advantage of existing infrastructure including network transmission, transmission upgrades, and gas supply infrastructure. The Company should be held to those identified cost savings for the purpose

19 PU-19-310 Set 2 Data Responses P 8
20 PU-19-310 Set 2 Data Responses P 22, 34

of granting an ADP. Even though the company issued an RFP for capacity and energy resources in 2018, it did not request solicitations explicitly for capacity resources. As a result, there is no price discovery regarding what a third party would be willing to offer a capacity resource for under a PPA.

Q. Did the Company preclude bidders from proposing a combustion turbine?

A. No, the Company did not specifically preclude a bidder from proposing a combustion turbine. However, my conclusion is that the language of the RFP did not suggest that what was ultimately the Company's preferred option (a CT coupled with market purchases where the rate payers take the energy price risk) was a bid option. The language from the RFP includes the following:

> In this Request for Proposal ("RFP"), Montana-Dakota requests competitive proposals ("Proposals") for capacity and energy resources totaling at least 10 megawatts (MW) and no more than 250 MW beginning June 1, 2025. Persons or entities responding to this RFP are referred to as "Respondents." Proposals received will be evaluated against a combined cycle natural-gas fired generation project that the Company is studying to construct, which is scheduled to have an on-line date of June 1, 2025, or later. [Montana-Dakota Utilities Co. Request for Proposal for Capacity and Energy Supply August 1, 2018 2019 IRP Volume 4, Appendix B, page 3 of 24]

The language of the RFP refers to both energy and capacity and comparing the bid against a combined cycle resource as opposed to the Company's current request for an ADP for a capacity resource only.

Q. Why are you recommending a limit on cost recovery under the ADP when the IRP had a scenario where the Heskett CT was still the preferred option under the high cost CT scenario?

A. The Company's modeling indicated that the Heskett CT is the preferred option even if the cost increased 20%. However, the Company has not conducted cost discovery through an RFP and the 20% cost increase assumption appears to apply to all the CT cost options.

Q. Do you have a specific recommendation regarding the approved recovery of costs?

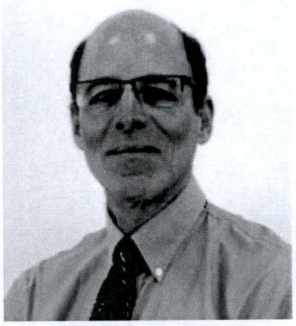
A. Yes, I recommend that any costs for gas and electrical interconnection above the $1.8M (for the entire project) identified by the Company be excluded from the ADP in order to help ensure that customers realize those anticipated savings. I also recommend limiting total recovery of $68.7M excluding AFUDC for the entire project (to be adjusted for the North Dakota allocation).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

JIM HEIDELL

DIRECTOR



Jim Heidell specializes in electric and gas utility regulation, economic analysis of damages in the utility and power sector, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. He has extensive financial and energy market modeling experience coupled with a deep understanding of regulated and competitive markets that he applies to the valuation of energy assets. Mr. Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. His regulatory experience and testimony includes rate design, cost of service, resource planning, and merger conditions. Mr. Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. Prior to working at PA Consulting he held positions as the Director of Finance and Director of Federal and State Regulation at Puget Sound Energy. Mr. Heidell is a CFA and has an MBA in finance from the University of Washington, a MS in Engineering Economics from Stanford University, and a BSE in civil engineering from Tufts University.

PRIMARY EXPERTISE

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation
- Strategic planning
- Financial modelling of complex investments
- Financial planning

QUALIFICATIONS

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University

CFA

EXPERIENCE SUMMARY

- **Utility Regulatory Support –** Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.
- **Damages Estimation for Civil Litigation Testimony** – Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages
- **Financial Analysis** – Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.
- **Renewable Energy Technologies** – Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.
- **Asset Valuation / M&A Advisor** – Provide valuation advice for acquisition electric utilities, gas distribution companies, electric generation portfolios, single power plants, transmission projects. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.

- **Gas & Electric Demand Forecasting** – Development of econometric and end-use models to forecast electric and gas consumption and peak demand.
- **Gas and Electric Utility Rate Forecasting** – Development of long- term retail rate forecasts in the U.S. and Mexican energy markets to support analysis of investment opportunities in rooftop solar, community solar, and retail energy service provider strategies and opportunities.
- **Analysis of Energy Markets** – Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

Prepared an analysis of claims of economic damage associated with the performance of an anaerobic digester designed to provide gas for an electric generation project. Analysis included evaluation of performance, revenues and costs, and cost of capital used to discount projected future earnings. Prepared expert report and testified in jury trial in federal district court.

Prepared an analysis to refute economic damages alleged by California American Water related to the cancellation of a desalination project in Monterey California. Analysis included review of financial statements, the ability of the utility to increase its earnings because of pursuing an alternative project, and the alleged lost of income.

Developed an analysis of material and labor cost increases on EPC costs for a natural gas fired power plant located in New Mexico. The analysis was used to refute a claim that cost overruns were not reasonable in a cost plus EPC contract. The analysis demonstrated how much of the total project cost increases was associated with labor and material costs beyond the control of the general contractor.

Prepared an analysis of loss of margins at two coal plants during periods when there were alleged violations of EPA opacity emission limits. The analysis demonstrated that client did not receive any economic benefit associated with the periods of alleged violations.

Prepared an analysis of the commercial distributed solar sector in the 2010 – 2011 time frame and demonstration of the unreasonableness of the plaintiff's claims for economic damages associated with the defendant's decision not to pursue participation in an equity fund.

Prepared an analysis of the U.S. wholesale electric power markets in the 2008 – 2010 time frame to demonstrate why the plaintiff's decision to terminate construction of a coal fired power plant was due to cost increases in the EPC contract and not due to the changing natural gas prices and emission laws.

Prepared an estimate of lost margins associated with the extended outage of a Canadian nuclear reactor. The analysis included an estimate of what Ontario wholesale power prices would have been but-for the outage and estimates of the total damages including repair and inspection costs.

Prepared an Expert Report regarding rate making and financial policies of the Southern Minnesota Municipal Power Agency in conjunction with a contract dispute regarding a power contract and investments in new generation resources to serve full requirements customers.

Assisted expert witness by the preparation of a report on how a third party would value the Trans-Alaska Pipeline as part of a property tax dispute with the municipality of Anchorage.

Prepared an analysis of damages associated with claims for losses associated with the interruption of business of a Texas gas-fired power plant as a result of the rupture of a natural gas pipeline use to supply the power plant.

Prepared of an analysis of the economic benefits that accrued to the defendant associated with the purported delay of implementation of measures to correct water pollution discharge violations associated with a power plant.

ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

Prepared an Independent Market Expert Report to support the debt financing of BrightSource Energy's Ivanpah solar thermal projects with purchased power agreements with California investor owned utilities.

Prepared an Independent Market Expert Report to support the debt financing of Solona, a large solar thermal project with molten salt storage, with a purchased power agreement with an Arizona Public Service.

Prepared an Independent Market Expert Report to support the expansion of a CdTe PV manufacturing facility in Colorado including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a c-Si PV manufacturing facility including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a polysilicon manufacturing facility including the analysis of the business plan and projection of long-term prices for polysilicon and the associated raw materials.

Prepared an evaluation of the global market for concentrating solar power plants as of 2012 as part of a client analysis of a potential purchase of a solar mirror manufacturing company.

Prepared an evaluation of the U.S. solar PV market to support evaluation of a Japanese firm's potential expansion in the U.S. markets.

Assisted client with a bid into a utility's renewable energy procurement program. The analysis included an assessment of competitors and analysis of pricing to support the bid of a renewable energy resource into 2011 Entergy RFP for renewable resources.

Prepared long range forecasts of multiple wind portfolios with an emphasis on the valuation of post PPA revenues and the value or renewable energy credits.

Prepared an analysis of the market for future expansion of the wind business of a major U.S. wind developer based upon an assessment of the competitiveness of wind generation with gas fired generation.

Prepared a fair market value analysis of associated with the purchase of a minority position in a wind project located in Ontario, Canada.

Prepared an Independent Market Expert Report to support the debt financing of a geothermal power project located in the Pacific Northwest.

Prepared an Independent Market Expert Report to support the debt financing of the Beacon flywheel energy storage project in New York.

Prepared an Independent Market Expert Report to support the debt financing of the AES battery energy storage project in New York. Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

UTILITY REGULATORY SUPPORT

Analysis and testimony on behalf of Constellation Energy Group related to typical merger and acquisition conditions required by regulators in utility and non-utility transactions. Testimony related to the EDF / Constellation joint venture.

Testimony related the use and design of ratchet rates on behalf of Northern Indiana Public Service Company. Testimony related to the application of ratchets to the client's unique position and appropriate recovery of costs.

Analysis of the economics of an electric utility's interruptible rates including the value of interruptions versus the payments received by customers. Developed recommendations for pricing interruptible rate programs that were consistent with the utility's avoided costs and ISO markets.

Developed electric cost-of-service studies, rate design, and testimony to support Puget Sound Energy in multiple general rate cases in Washington. The engagements included addressing issues such as special rates for strategic customers with competitive options, line extension policies, and rates to address revenue attrition.

Developed natural gas cost-of-service studies, rate design, and testimony to support Puget Sound Energy in a general rate case in Washington.

Prepared marginal cost of service studies and testimony to support Montana-Dakota utilities in multiple Montana rate cases.

Assist Montana-Dakota Utilities in development of its integrated resource plan through analysis of options using the Strategist planning model.

Supported Montana-Dakota Utilities in answering a complaint in front of the South Dakota Public Utilities Commission regarding a wind generator requesting a contract under the provisions of PURPA.

Provided expert testimony related to Montana Dakota's proposed participation in the Big Stone II power plant. Prepared and delivered testimony provided in multiple hearings in North Dakota and Minnesota.

Prepared testimony on behalf of Hydro One Networks regarding rate shock and how to address necessary rate changes associated with the restructuring of the electric utility business in Ontario.

Developed an analysis or weather risk associated with the retail power sales of IPALCO. Effort was conducted as part of a comprehensive risk assessment conducted by AES. Models of the weather / load relationship were developed and then integrated with the rate structures and cost adjustment mechanisms to assess the utility's overall exposure to weather risk.

Advised Old Dominion Electric Cooperative on options for acquiring new generation in a depressed power market and incorporation of the analysis in their long-term resource planning.

M&A and BANKRUPTCY ADVISOR

Prepared an analysis of New Mexico Gas Company to support a prospective buyer. We assisted multiple clients with due diligence related to the acquisition of gas LDCs. Assisted the client with a review of the deal model including: assumptions about rate cases, assumptions regarding ROE, sales growth by rate class, and revenue by rate class. The engagement also included an assessment of the regulatory climate and potential conditions and costs associated with obtaining regulatory approval of the transaction.

Prepared a valuation of the Mountaineer Gas Company including the analysis of regulatory issues to support the debt financing associated with the purchase of the energy company.

Assisted an infrastructure fund in valuing power contracts and reviewed the regulatory model used in conjunction with establishing the price to bid for the acquisition of Northwestern Utility.

Prepared an analysis of Duquense Light to support an infrastructure fund's bid for the utility. The analysis included projections of growth opportunities through distribution & transmission investment, analysis of the POLR load obligation, and a review of key regulatory issues.

Developed a valuation model of Mirant including analysis of debt carrying capacity to assist a strategic player in the U.S. Power Industry determine whether to make an unsolicited offer to purchase Mirant.

Assisted an international oil company in development of modelling processes and assumptions to support a corporate effort to acquire a fleet of U.S. merchant generating assets.

Support a strategic player in valuing the Lake Road Generation Plant as part of their bid to acquire the asset in a competitive auction. Effort involved projection of future gross margins of the plant, analysis of the ISO-NE Forward Capacity Market, and analysis of transmission constraints.

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG. Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

Member of team that advised Calpine as part of the company's restructuring and plan of reorganization. Assignment included analysis of the Canadian portfolio, advising on the sale of generation assets, modelling of long-term turbine maintenance costs, and the valuation of complex power contract.

Assisted the lenders on valuation and strategy related to AES' turn-back of the Granite Ridge Power Plant to the lender group.

Advised the bank and lender group on valuation and strategy related to the bankruptcy of the Kendall Power Plant.

ASSET APPRAISALS

Prepared a valuation of a large eastern coal plant as a third party appraiser required in a transaction where the lessee wanted to exercise a buy-back provision in a sale lease-back agreement.

Prepared a valuation of a California cogeneration plant for the purposes of identifying the tax loss.

Completed an appraisal to support the transfer of the Trans Bay Cable from the development arm to a separate fund managed by the infrastructure fund. The appraisal addressed the California power markets, operations of the CA ISO high voltage transmission and a forecast of revenues given the FERC and CA-ISO regulatory schemes as part of the income approach. The appraisal also incorporated a comparable sales and replacement cost analysis.

Developed an appraisal of a nuclear power plant based upon discounted cash flow, replacement costs, and comparable sales as part of an effort to determine the fair market value under a lease agreement that contained a buy-back provision.

Completed multiple appraisals of the KeySpan generation assets on Long Island that were subject to a generation repurchase agreement with LIPA. The appraisals were part of the ongoing process for KeySpan to develop a strategy to address the LIPA repurchase option.

Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

ELECTRIC GENERATION FINANCE SUPPORT

Market expert report for the Landfill Energy Systems, a national 66 MW portfolio of fourteen landfill gas power plants. The market expert report included a discussion of the key attributes of each of the power markets that the portfolio encompasses, long-term forecasts of wholesale electricity prices, and forecasts of gross margins.

Independent Market Expert Report to support the financing of the repowering and development of a fleet of combined cycle and simple cycle power plants in the ERCOT market. The independent market expert report was used to support the syndication of loans and obtaining debt ratings associated with investing over $1 billion in the Barney Davis, Nueces Bay, and Laredo Energy Center facilities.

Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the syndication and rating of over $400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over $100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

ELECTRIC MARKETS RISK MODELING

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

DSM ADVISORY SERVICES

Advised Con Edison on the status of electric decoupling and incentive mechanisms in the United States as part of the New York state initiative to reintroduce decoupling.

Advised a private equity fund on the status of demand side management in New England, likely projections of growth, and probability of successful implementation as part of an evaluation of long-term supply and demand conditions in the New England electric markets.

Worked with Montana-Dakota utilities regarding the incorporation of projections of demand side management potential into the utility's long-term resource plan.

ADDITIONAL EXPERIENCE – EXPERT TESTIMONY

Before the Superior court of the State of California, California-American Water Company vs. Marina Coast Water District; RMC Water and Environment, Case No. CGC-15-546632. Expert Report on behalf of RMC with respect to alleged damages by Cal-Am Water.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter of Northern States Power Company Advance Prudence – Dakota Range Wind Application, Case No. PU-17-372.

Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the Hawaii Public Service Commission, Direct Testimony of James A. Heidell, Docket No. 2017-0105 In The Matter of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Otter Tail Power Company Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – 1,550 MW Wind Portfolio, Case No. PU-17-120.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING, Case Nos. PU-17-270, PU-17-271, & PU-17-322.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company A Minnesota Corporation D/B/A XCEL Energy Jurisdictional Cost Allocation Matters, Case Nos. PU-12-813 et. al.

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

	A	B	C	D	E	F	G	H	I
1	**Retirement Savings with Montana-Dakota Base Case MISO Price Forecast**								
2									
3	**Retirement 2029**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
4	Off-Peak MISO	$/MWH	23.3	24.0	24.7	25.5	26.2	27.0	27.8
5	On-Peak MISO	$//MWH	26.8	27.6	28.4	29.2	30.1	31.0	31.9
6									
7	Off-Peak MISO Purchases	MWH	772,680	796,270	800,000	800,000	800,000	800,000	800,000
8	On-Peak MISO Purchases	MWH	28,710	89,340	172,170	83,830	103,150	233,680	293,290
9									
10	Heskett Fixed Cost	$(000)	11,334	11,621	11,915	12,153	12,396	12,644	12,897
11	Lewis & Clark #1 Fixed Cost	$(000)	6,835	7,011	7,191	7,335	7,482	7,631	7,784
12									
13	Fuel & VOM Costs	$(000)	43,299	43,670	43,954	69,929	72,482	71,747	72,994
14	MISO Market Purchases	$(000)	18,771	21,572	24,662	22,818	24,082	28,854	31,624
15	Incremental Capacity Purchases	$(000)							
16									
17	Total	$(000)	80,240	83,874	87,722	112,235	116,442	120,877	125,299
18									
19									
20	**Retirement 2023**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
21	Off-Peak MISO	$/MWH	23.3	24.0	24.7	25.5	26.2	27.0	27.8
22	On-Peak MISO	$//MWH	26.8	27.6	28.4	29.2	30.1	31.0	31.9
23									
24	Off-Peak MISO Purchases	MWH	800,000	800,000	800,000	800,000	800,000	800,000	800,000
25	On-Peak MISO Purchases	MWH	260,300	354,920	467,300	355,340	394,920	544,570	585,350
26									
27	Heskett IV Non Fuel Revenue Req	$(000)	10,642	10,545	10,300	10,072	9,861	9,663	9,476
28	Plant Decommissioning Revenue Requirement	$(000)	1,416	1,557	1,557	1,557	1,557	1,557	1,557
29	Employee Retention Package	$(000)	1,413	1,413	1,413	1,413	1,413	0	0
30									
31	Fuel & VOM Costs	$(000)	27,201	27,076	26,413	52,193	53,546	51,916	53,865
32	MISO Market Purchases	$(000)	25,603	28,978	33,038	30,755	32,867	38,495	40,952
33	Incremental Capacity Purchases	$(000)	2,867	2,924	2,982	3,042	3,103	3,165	3,228
34									
35	Total	$(000)	69,141	72,493	75,703	99,033	102,347	104,797	109,079
36	Total w/o Decomissioning Costs	$(000)	67,728	71,080	74,291	97,620	100,934	104,797	109,079
37									
38									
39	**Summary**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
40	Total Savings	$(000)	11,099	11,381	12,019	13,203	14,095	16,080	16,220
41	Total Savings w/o Decomissioning Costs	$(000)	12,511	12,794	13,431	14,615	15,508	16,080	16,220
42	North Dakota Share	$(000)	9,071	9,276	9,738	10,596	11,243	11,658	11,760
43									
44	North Dakota Forecast Sales	MWH	2,308,626	2,340,078	2,370,296	2,402,618	2,435,405	2,468,656	2,502,388
45	Average Rate Savings	$/kWH	0.00393	0.00396	0.00411	0.00441	0.00462	0.00472	0.00470

	A	B	C	D	E	F	G	H	I
1	**Retirement Savings with Montana-Dakota High MISO Price Forecast**								
2									
3	**Retirement 2029**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
4	Off-Peak MISO	$/MWH	33.3	34.0	34.7	35.5	36.2	37.0	37.8
5	On-Peak MISO	$//MWH	36.8	37.6	38.4	39.2	40.1	41.0	41.9
6									
7	Off-Peak MISO Purchases	MWH	772,680	796,270	800,000	800,000	800,000	800,000	800,000
8	On-Peak MISO Purchases	MWH	28,710	89,340	172,170	83,830	103,150	233,680	293,290
9									
10	Heskett Fixed Cost	$(000)	11,334	11,621	11,915	12,153	12,396	12,644	12,897
11	Lewis & Clark #1 Fixed Cost	$(000)	6,835	7,011	7,191	7,335	7,482	7,631	7,784
12									
13	Fuel & VOM Costs	$(000)	43,299	43,670	43,954	69,929	72,482	71,747	72,994
14	MISO Market Purchases	$(000)	26,785	30,428	34,384	31,657	33,113	39,191	42,557
15	Incremental Capacity Purchases	$(000)							
16									
17	Total	$(000)	88,254	92,730	97,444	121,074	125,474	131,213	136,232
18									
19									
20	**Retirement 2023**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
21	Off-Peak MISO	$/MWH	33.3	34.0	34.7	35.5	36.2	37.0	37.8
22	On-Peak MISO	$//MWH	36.8	37.6	38.4	39.2	40.1	41.0	41.9
23									
24	Off-Peak MISO Purchases	MWH	800,000	800,000	800,000	800,000	800,000	800,000	800,000
25	On-Peak MISO Purchases	MWH	260,300	354,920	467,300	355,340	394,920	544,570	585,350
26									
27	Heskett IV Non Fuel Revenue Req	$(000)	10,642	10,545	10,300	10,072	9,861	9,663	9,476
28	Plant Decommissioning Revenue Requirement	$(000)	1,416	1,557	1,557	1,557	1,557	1,557	1,557
29	Employee Retention Package	$(000)	1,413	1,413	1,413	1,413	1,413	0	0
30									
31	Fuel & VOM Costs	$(000)	27,201	27,076	26,413	52,193	53,546	51,916	53,865
32	MISO Market Purchases	$(000)	36,206	40,527	45,711	42,308	44,816	51,941	54,806
33	Incremental Capacity Purchases	$(000)	2,867	2,924	2,982	3,042	3,103	3,165	3,228
34									
35	Total	$(000)	79,744	84,042	88,376	110,586	114,296	118,242	122,933
36	Total w/o Decomissioning Costs	$(000)	78,331	82,630	86,964	109,173	112,883	118,242	122,933
37									
38									
39	**Summary**	**Units**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
40	Total Savings	$(000)	8,510	8,688	9,067	10,488	11,178	12,971	13,299
41	Total Savings w/o Decomissioning Costs	$(000)	9,922	10,101	10,480	11,900	12,590	12,971	13,299
42	North Dakota Share	$(000)	7,194	7,323	7,598	8,628	9,128	9,404	9,642
43									
44	North Dakota Forecast Sales	MWH	2,308,626	2,340,078	2,370,296	2,402,618	2,435,405	2,468,656	2,502,388
45	Average Rate Savings	$/kWH	0.00312	0.00313	0.00321	0.00359	0.00375	0.00381	0.00385

Exhibit JAH-2

Retirement Savings with PA MISO Price Forecast

Retirement 2029	Units	2023	2024	2025	2026	2027	2028	2029
Off-Peak MISO	$/MWH	23.8	25.1	26.3	27.1	28.3	29.2	30.3
On-Peak MISO	$//MWH	32.9	35.1	36.7	37.9	39.5	40.9	42.9
Off-Peak MISO Purchases	MWH	772,680	796,270	800,000	800,000	800,000	800,000	800,000
On-Peak MISO Purchases	MWH	28,710	89,340	172,170	83,830	103,150	233,680	293,290
Heskett Fixed Cost	$(000)	11,334	11,621	11,915	12,153	12,396	12,644	12,897
Lewis & Clark #1 Fixed Cost	$(000)	6,835	7,011	7,191	7,335	7,482	7,631	7,784
Fuel & VOM Costs	$(000)	43,299	43,670	43,954	69,929	72,482	71,747	72,994
MISO Market Purchases	$(000)	19,305	23,146	27,370	24,881	26,710	32,889	36,846
Incremental Capacity Purchases	$(000)							
Total	$(000)	80,773	85,448	90,430	114,298	119,070	124,911	130,521

Retirement 2023	Units	2023	2024	2025	2026	2027	2028	2029
Off-Peak MISO	$/MWH	23.8	25.1	26.3	27.1	28.3	29.2	30.3
On-Peak MISO	$//MWH	32.9	35.1	36.7	37.9	39.5	40.9	42.9
Off-Peak MISO Purchases	MWH	800,000	800,000	800,000	800,000	800,000	800,000	800,000
On-Peak MISO Purchases	MWH	260,300	354,920	467,300	355,340	394,920	544,570	585,350
Heskett IV Non Fuel Revenue Req	$(000)	10,642	10,545	10,300	10,072	9,861	9,663	9,476
Plant Decommissioning Revenue Requirement	$(000)	1,416	1,557	1,557	1,557	1,557	1,557	1,557
Employee Retention Package	$(000)	1,413	1,413	1,413	1,413	1,413	0	0
Fuel & VOM Costs	$(000)	27,201	27,076	26,413	52,193	53,546	51,916	53,865
MISO Market Purchases	$(000)	27,581	32,564	38,213	35,165	38,237	45,618	49,379
Incremental Capacity Purchases	$(000)	2,867	2,924	2,982	3,042	3,103	3,165	3,228
Total	$(000)	71,119	76,079	80,879	103,443	107,717	111,920	117,506
Total w/o Decomissioning Costs	$(000)	69,706	74,666	79,466	102,030	106,304	111,920	117,506

Summary	Units	2023	2024	2025	2026	2027	2028	2029
Total Savings	$(000)	9,654	9,370	9,551	10,855	11,353	12,992	13,015
Total Savings w/o Decomissioning Costs	$(000)	11,067	10,782	10,964	12,267	12,766	12,992	13,015
North Dakota Share	$(000)	8,024	7,817	7,949	8,894	9,255	9,419	9,436
North Dakota Forecast Sales	MWH	2,308,626	2,340,078	2,370,296	2,402,618	2,435,405	2,468,656	2,502,388
Average Rate Savings	$/kWH	0.00348	0.00334	0.00335	0.00370	0.00380	0.00382	0.00377

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **Advance Prudence – Heskett 4** **Application**	**Case No. PU-19-306**
Montana-Dakota Utilities Co. **88 MW Turbine – Heskett 4** **Public Convenience & Necessity**	**Case No. PU-19-307**

VERIFICATION

STATE OF _____Colorado______)
) ss.
COUNTY OF ______Denver_____)

James A. Heidell, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

J. a. Heidell
James A. Heidell

Subscribed and sworn to before me this 19th day of February, 2020.

HASAN BAQER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20194028347
MY COMMISSION EXPIRES JULY 29, 2023

Notary Public
My Commission Expires: July 29, 2023