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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. 2020 Natural Gas Rate Increase Application	))	**Case No. PU-20-379**

DIRECT TESTIMONY

OF

JAMES A HEIDELL

ON BEHALF OF

THE NORTH DAKOTA PUBLIC SERVICE COMMISSION ADVOCACY STAFF

January 15, 2021

Contents

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 overall assessment of Montana-Dakota Utilities' (MDU or the Company) request for a natural gas rate increase of 7.8% based upon my testimony as well as the testimony of Mr. Jeanson and Mr. Rothschild;

- Review of the proposed rate year sales volumes;

- Provide my recommendations for the allocation of the rate increase based upon the adjustments to the revenue requirement proposed by Mr. Jeanson and Mr. Rothshchild and my suggestions for modifying the cost of service study present by Montana-Dakota's witness Mr. Amen;

- Provide my recommendations related to the rate increase and phase in of rates for Whapeton / Great Plains;

- Provide my recommendation related to changes in the Montana-Dakota line extension policy; and

- Provide my recommendation with regards to charges for customers who elect to opt-out of automated meter reading

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

A. Yes. I start with an overview of the conclusions presented by myself as well as witnesses Mr. Jeanson and Mr. Rothschild on behalf of Advocacy Staff. I then present my recommendations with regards to modifications of the cost of service study put forth by Montana-Dakota. Next, I present my proposed modifications to the rate design and tariffs requested by the Company. Finally, I discuss the class allocation of the rate increase ultimately approved by the Commission

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

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Would you please provide a summary of the findings related to Montana-Dakota's request for a 7.8% rate increase?

A. As presented by Advocacy Staff witnesses Mr. Jeanson and Mr. Rothschild, the following adjustments to the Montana-Dakota revenue requirement are recommended;

- The distribution capital adjustments for 2020 and 2021 should be reduced by $1,014,462 for 2020 and $754,711 for 2021 million due to projects that will not be completed in that time frame. In addition, CapEx should be reduced by $1M associated with meter additions. The basis for these adjustments are explained by Mr. Jeanson;
- The Company should not be granted a return on pension balances of approximately $59.8M that is associated with cash contributions in excess of pension expense recovered in rates;
- Executive incentive compensation of $361,158 should be excluded per the testimony of Mr. Jeanson; and

- An appropriate cost of equity is 8.09% versus the 10.2% ROE requested by the Company.

Q. Have you estimated the rate increase based upon the proposed adjustments?

A. Yes, I entered the proposed adjustments in the Company's Embedded CCOS study to estimate the impacts. My estimate is that the overall rate increase will be on the order of 4.47% associated with a requested 12.78% increase in distribution costs.

Q. Would you please your recommendations related to Montana-Dakota's embedded cost of service study?

A. Yes, as I discuss in my testimony the large increase in the distribution rate base is associated with pipe replacement as part of the System Safety & Integrity Main Replacements and Service Replacements program. These replacements are not being made to either accommodate load or customer growth and the cost of these replacements are not based upon the economics of serving the load. I assume that these are cost justified based upon societal benefits, i.e. avoiding the damage to property or more consequential; avoiding injury and loss of life. Consequentially I recommend allocating these costs on a volumetric basis.

Q. Would you please your recommendations related to Montana-Dakota's proposal for allocating the rate increase across classes?

A. I support the Company's proposal for the allocation of a minimum rate increase to each class and I recommend that the residential class should not receive more than a 10% rate increase. I understand that the Commission may choose an alternative allocation of the rate increase. In any alternative allocation I recommend that no class get a rate decrease given a combination of the Company's cost of service results and the challenges and lack of precision in the allocation of costs to the rate classes.

Q. Would you please provide a summary of the findings related to Montana-Dakota's rate design?

A. Yes, I am supportive of the harmonization of the rates but I am concerned about the timing. Customers will have three rate changes, excluding the cost of gas, within a two-year period and based upon the Company's calculations, some customers will have significant percent increases in their bills. These changes will also be associated with a change in bill as the Company moves these customers over to the Montana-Dakota tariff. Based upon the past frequency of Montana-Dakota rate changes, it is my recommendation that the rate change associated with Phase II be deferred until the next rate case.

III. REVIEW OF MONTANA DAKOTA'S COST OF SERVICE STUDY

Q. Have you reviewed the cost of service study developed by Mr. Amen?

A. Yes, I reviewed the cost of service and I would like to focus on the allocation of distribution mains across the rate case. Based upon my review of the testimony of Ms. Kivisto and Mr. Darras, I have concluded that a disproportionate share of cost has fallen on the residential rate class where the Company is recommending a 30.2% increase in distribution rates (12.5% rate increase including the cost of gas) versus and 18.2% rate increase (6.6% overall rate increase) for the small firm general service customers.

Q. How did the Company allocate the cost of distribution mains?

A. The cost of distribution mains that are not directly assigned was first classified as 30% customer related and 70% demand related. The customer related costs were allocated to the rate classes based upon customer counts while demand related costs are allocated to each class based upon each class' contribution to peak day demand.

Q. How was the 30% / 70% derivation derived?

A. The company did an approximate average of their zero-intercept analysis (25.9% customer cost) and the minimum system method (35.4% customer cost).

Q. Is taking an average of the two approaches reasonable?

A. Both approaches are theoretical constructs to separate out a joint cost, i.e. the distribution system is built to serve customers as well as sized to serve peak loads. Neither approach appears to reflect current system design practices. For example, the Company's minimum system calculation is based upon approximately 55% of the miles of pipe being 2" plastic, while the extensive rebuild of the system under the Distribution Integrity Management Program (DIMP) uses 2" plastic pipe for 75% of the miles of pipe installed. The zero-intercept that postulates a customer cost of 0" pipe is also not a reflection of actual system construction. Neither approach appears to reflect actual system design, the ten percent difference is indicative that that there is not a single correct approach, and the Company has not made a case for why either method is more correct. While I believe that the minimum system approach makes more sense at least from having a semblance of an engineering basis, I can accept the averaging with the exceptions noted below. The averaging has the advantage of reducing the impact of shifting cost allocations on parity ratios given that in the prior rate case the Company proposed a 25% customer allocation.[1]

Q. Please summarize the significance of the recent investment in distribution mains?

A. Ms. Kivisto notes that rate base has increased $36.3M, or 24% between 2018 and the projected balance in 2021[2]. As noted by Ms. Kivisto, the primary driver of the rate increase is the Company's investment in safety and reliability of the distribution system.[3] The Company has invested $11M in safety and reliability between 2017 – 2019 and expects to invest an additional $43.1M in safety and reliability between 2020 – 2024.[4] Based upon information provided by the Company approximately $30M of the investment between 2019 – 2021 is for safety versus $2.8M for capacity[5]. Based upon this investment split, my conclusion is that a large driver of the rate increase is the Company's substantial capital investment in replacing gas mains as part of the Distribution Integrity Management Program (DIMP) and System Safety and Integrity Program (SSIP).

Q. How is the investment in distribution mains for safety classified and allocated to the customer classes?

A. With the exception of distribution main costs that are directly assigned, the Company classifies the investment in all distribution mains as either customer, or demand based upon

[1] Prefiled Direct testimony of Jordan Hatzenbuhler, Docket No. PU-17-295, p. 5, lines 12 - 14
[2] Direct testimony of Ms. Kivesto p 14, lines 3 – 5.
[3] Direct testimony of Ms. Kivesto p 12, lines 15 – 17.
[4] Direct testimony of Ms. Kivisto p 9 lines 1 – 6.
[5] The $2.8M for capacity includes the Jamestown Town Border Station (TBS) project which is not expected to continue. See Mr. Jeanson's testimony for further detail regarding this project.

the previous discussed average of the zero-intercept and minimum system methods. The customer and demand components are allocated to classes based upon customers and peak design day for the demand portion.

Q. Is the average of the zero-intercept and minimum system methods an appropriate method for splitting the distribution pipe replacement program costs between capacity and customer costs?

A. There are a number of methods used to classify distribution main investments and those methods include the zero-intercept approach and the average and excess demand approach. These cost classification approaches share the underlying concept that part of the costs are associated with serving peak demand. However, the fundamental principle behind any cost classification and allocation method is whether the cost allocation follows the cost causation. The minimum system is based upon a theoretical that the costs in excess of the minimum system to connect a customer is capacity related. Alternatively, the intercept in the zero-intercept is the cost of a pipe of no diameter, a nonsensical system design. The minimum system calculation presented by Mr. Amen does not necessarily reflect cost causation. Mr. Amen's minimum system calculation assumes that any pipe over 2" is for demand. However, the Company notes that it installs 4" pipe at times to allow for future growth in areas far from a sole source point. In addition, when I reviewed the Company's data on installation of all pipe from 2017 – 2020 it appears that 55% of the cost was associated with 2" pipe.

Q. Was 2" Polyethylene (PE) pipe predominately used in the replacements for safety?

A. Yes, 75% of the mains installed by linear feet was 2" PE mains. I also note that the cost per foot for 2" PE mains for the projects that only used 2" PE was $25.81/foot versus the number used by Mr. Amen of $19.59/ft.

As Mr. Amen notes, "main costs vary with either growing design day demand or a growing number of customers".[6] In the instance of the replacements for safety, it appears that the decision to install 4" PE was in part due to the number of customers on the line versus peak demand. As the Company noted that they install 4-inch pipe in instances where they

[6] Prefiled Direct Testimony of Mr. Amen, P 6, lines 18 – 20.

anticipate customer growth when expanding in areas far from a sole source point. Accordingly, a 2” pipe is not always the minimum size pipe installed.

Project	Mains Description	Mains Cost	Mains Cost/Customer	Service Lines	Service Lines Cost	Service Cost / Customer
Richardton	19,600’ 2” PE	456,894	3,776	121	317,020	2,620
Barlow	3,000' 2” PE	80,433	10,054	8	31,947	3,993
Taylor	12,700' 2” PE	274,088	4,493	61	174,329	2,858
Gladstone	9,000' 2” PE	305,870	5,462	56	202,603	3,618
Eldridge	3,000’ 2” PE	103,367	5,440	19	62,912	3,311
Cleveland	210’ 2” PE 330’ 4” PE 420’ 4” steel	54,307	27,154	2	9,200	4,600
Fairview	16,500’ 2” PE 1,250’ 4” PE 595’ 4” steel	406,876	7,677	53	201,625	3,804
Glen Ullin	28,000' 2” PE 6,000' 4” PE	1,082,964	2,648	409	841,622	2,058
New Salem	29,200’ 2” PE 17,000' 4" PE 510' 4" steel	1,610,131	4,171	386	946,881	2,453
Dickinson	47,000' 2" PE 17,700' 4" PE 7,600' 6" PE 4,100' 12" PE 510' 6" Steel	6,558,656	6,748	972	4,750,291	4,887

Q. Are the costs related to the DIMP necessitated by the need to meet customer peak demands?

A. No, the DIMP is a safety program. In fact, when reviewing the projected peak demand allocation factors in the current and prior Montana-Dakota rate cases, the design day demand has decreased from 192,668 dekatherms projected for 2018 to 186,638 dekatherms projected for 2021[7].

[7] Prefilled Workpapers in Case No. PU-17-295 and Case No. PU-20-379

Q. Are you recommending that the Commission modify the Company's allocation of the cost of distribution mains associated with the pipe replacements?

A. Yes. I recommend that the Company apply the Projected Throughput Allocation Factor (Factor No. 1) for the distribution mains investments that are related to safety, instead of including these investments as 30% customer related and 70% demand related and then allocated based off number of distribution customers and peak design day respectively.

Q. Please explain your reasoning for the recommended change in allocation?

A. The Company's peak design day is decreasing, yet safety related distribution investments are a significant component of capital investment spend. Ms. Kivisto notes that the primary driver for increased rates is for the safety and reliability investment of the distribution system[8]. The Company also stated that when considering safety related projects, the cost per customer as well as the number of customers served is not a consideration on whether a safety related project will be pursued.

As a result, I find allocating safety related investments volumetrically, based on a Projected Throughput Allocation Factor, is more appropriate than allocating safety related investments based off number of customers and peak capacity.

The recommended allocation factor change for safety related investments will ensure all customer classes pay their share of safety expenditures based off their system usage.

Q. Is there any precedent for the Commission not strictly following the distribution mains allocation methodology proposed by Mr. Amen?

A. Yes, in the Commission's order in Docket PU-17-295 the Commission noted the following

> "The Commission has traditionally avoided the mechanical application of the results of any class cost of service study, applying its own judgement after considering the evidence, arguments, and public policy to reach an appropriate rate design in a particular case."

[8] Direct testimony of Ms. Kivesto p 12, lines 11 – 19.

Furthermore, Mr. Amen's proposed allocation methodology does not have a clear precedent as the use of the zero-intercept method as part of the distribution mains allocation methodology was not used in the Company's prior rate case.

Q. Are you questioning the prudence of the safety investments?

A. No, I have reviewed the testimony of Mr. Darras regarding the DIMP and I am not an expert on pipeline safety. I do not have an opinion as to whether the specific pipelines replaced should have been replaced for safety reasons. However, I note that there it is a significant cost and the cost per customer appears to me well in excess of the costs that would be paid by the company under its line extension policy. Therefore, these replacement programs would not pass the criteria for the Company to economically add these customers. This is not to imply that the investment in safety is not cost effective. The cost of damage to property or more consequential, human injury of loss of life is extremely high. Hence there is an implied different standard to the value of continuing to serve a customer versus adding a customer. The societal benefits presumably justify the replacements on a cost-effectiveness test. However, I do not conclude that allocation of these costs based upon safety ties to using an allocation method that is the average of the minimum-system and zero-intercept methods.

IV. RATE YEAR SALES VOLUMES

Q. Have you reviewed the rate year sales forecast?

A. Yes, I have reviewed the testimony and exhibits developed by Mr. Shoemake to ensure it is reasonable. A reasonable forecast is a critical input into determining whether the proposed rates are expected to recover the revenue requirement and not over-recover the revenue requirement.

Q. Please summarize your understanding of the process that the Company used to project sales volumes?

A. The Company used 2019 actual volumes as a starting point. Volumes associated with heat-sensitive customers were adjusted using an Ordinary Least Squares (OLS) regression analysis over a 3-year time period. The Company included all firm service customer classes as heat-sensitive volumes, excluding 57 transposition customers who have a firm service agreement.[9] The remaining customer classes were split between heat-sensitive and non-heat sensitive customers.[10] The Company then used the 2019 weather normalized heat-sensitive volumes to project 2020 and 2021 heat-sensitive volumes based on the projected number of customers.

Normalized volumes for non-heat sensitive customers were based on the individual customer's average volumes over Jan 2017 – Dec 2019. Shorter periods were used when historical data was limited or considered as not an accurate depiction of future consumption.[11] The 2020 and 2021 non-heat sensitive volumes were projected to remain at the 2019 normalized non-heat sensitive volumes. [12]

Q. Is a 3-year historical time period used for the Ordinary Least Squares (OLS) regression analysis consistent with prior Montana-Dakota Rate Cases?

A. Yes. The Company used a 3-year (36-month) time period for the Ordinary Least Squares (OLS) regression analysis in their prior rate case, Case No. PU-17-295, as well.[13]

Q. Does the choice of the 3-year time period impact the results?

A. Yes. The Company used 3-years of historical data from Jan 2017 - Dec 2019. Suppose the Company instead used a rolling 3-years from Dec 2017 – Nov 2020 for the Small and Large Firm General customer classes (excluding operational seasonal and contracted demand customers). In that case, the impact will be a slight increase in usage which will result in a slightly lower revenue deficiency. Note, we excluded the residential class since distribution costs are not recovered on volumetric charges.

Q. Does the degree day data used in the Ordinary Least Squares (OLS) regression reflect the different customer regions?

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9 The Minot Air Force Base firm accounts were separated between heat and non-heat sensitive

10 Direct testimony of Mr. Shoemake p 3, lines 16 – 19.

11 Direct testimony of Mr. Shoemake p 5, lines 4 – 16.

12 Direct testimony of Mr. Shoemake p 6-7, lines 20 – 23 and 1 - 2.

13 Case No. PU-17-295. Direct testimony of Mr. Shoemake p 3, lines 10 – 12

A. Yes. The Company purchases raw degree day data from DTN and then performs calculations to develop a system-wide North Dakota Billing Period Degree Day (BPDD). These calculations consider; the weather in the different regions served, the number of customers served in each region, and the number of days in each billing cycle for the given month. The system-wide BPDD is based on the weighted average degree days across six regions.[14]

Q. How does the Company use the Ordinary Least Squares (OLS) regression results in determining normalized usage?

A. The Company performs the normalization calculation on a monthly basis. For each month, the month's days are multiplied by the regression intercept to come up with the baseload per customer. The normalized heating usage per customer is then calculated based on a monthly normal degree day multiplied by the Ordinary Least Squares (OLS) regression slope. The normal degree day data is based on historical 30-years. The total use per customer for all months is then multiplied by the average customers over the respective months to develop the total annual normalized usage for the customer class.[15]

Q. Is the Company's normalization process reasonable?

A. Yes. The Company's use of Ordinary Least Squares (OLS) regression to break out the base usage and non-base usage of Firm customers is reasonable. The R-squared of the Regression results were all high, over 85%, suggesting the Company's use of degree days as an independent variable is a good way to determine customer usage patterns. The Company's 2019 total Residential and Firm General volumes per books (including operational seasonal and contracted demand customers) was 18,344,443 and weather normalized volumes were 16,744,524. As noted earlier, using a more recent time period for the Ordinary Least Squares (OLS) regression analysis will result in a slight increase to the Firm service customer classes weather normalized volumes.

Q. How did the company project the number of customers?

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[14] The seventh region purchased from DTN, which represents the Dickinson weather district, is used for Montana-Dakota's propane customers (Rates 900/920/921) as these customers are based solely in the Dickinson territory.

[15] [15] Direct testimony of Mr. Shoemake p 4-5, lines 14 – 23 and 1 - 3.

A. The Company used the 3-year average growth rate in the Residential, Small Firm General, and Large Firm General customer classes to project the number of customers per customer class in 2020 and 2021. No growth was projected for the other customer classes; all other customer classes were projected to remain at 2019 levels.[16]

Q. Did the Company use the most recent customer data for the 3-year historical customer growth rate analysis?

A. No. The Company used the number of customers from 2016 - 2019 for the 3-year average growth rate. Although a more recent period, such as using YTD 2020 number of customers, maybe more appropriate under normal circumstances, due to the Covid-19 pandemic, I find that the historical period used by the Company is reasonable. The Company increased measures to avoid customer disconnects, which can result in a higher than usual number of customers in 2020.

Q. Has the Company historically used a 3-year average customer growth rate to project the Residential, Small Firm General, and Large Firm General customer classes in their prior rate case?

A. No. The Company used a 2-year average growth rate to project the Residential, Small Firm General, and Large Firm General customer classes in their prior rate case. In addition, the Company also applied the Small Firm General growth rate to project the Large Firm General customer class in the prior rate case due to the growth rate for the Large Firm General customer class not being representative of future customer growth.[17]

Q. Did you analyze the impact of the change in methodology for projecting the number of Residential, Small Firm General, and Large Firm General customers?

A. Yes. The Company's use of a 3-year historical annual average number of customers as the basis for future customer growth results in a small decrease in the projected number of residential customers. If the Company were to use a 2-year historical average, the residential

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[16] Direct testimony of Mr. Shoemake p 10, lines 1 – 12.
[17] Case No. PU-17-295. Direct testimony of Mr. Shoemake p 5-6, lines 16 – 20, and 1-12

Basic Service Charge would decrease slightly due to the marginally higher projected residential customer count. However, total projected customers under the 3-year methodology is higher due to the higher growth rates for small and large firm general customer classes. Due to the small difference of moving from a 2-year average to a 3-year average customer growth rate, based on the Company's 2016-2019 average customers, I find the Company's use of a 3-year average customer growth rate under these circumstances to be within reason.

	Residential Rate 600	**Residential Wahpeton**	**Small Firm Rate 700**	**Large Firm Rate 701**	**Firm General Wahpeton**
2016 Average Customers	93,739	1,780	10,293	4,463	387
2017 Average Customers	94,090	1,828	10,482	4,609	395
2018 Average Customers	94,519	1,851	10,699	4,700	409
2019 Average Customers	95,057	1,851	10,786	4,760	410
2-year Average Increase	**0.52%**	**0.63%**	**1.44%**	**1.63%**	**1.89%**
Projected Average Customer Increase *(based off 2019)*	**494**	**12**	**155**	**78**	**8**
3-year Average Increase	**0.47%**	**1.32%**	**1.57%**	**2.17%**	**1.95%**
Projected Average Customer Increase *(based off 2019)*	**447**	**24**	**169**	**103**	**8**

Q. Are you recommending that Montana-Dakota's approach of using three years versus two-year averages be used in future rate cases?

A. No, the use of three years should not be considered a precedent.

V. GREAT PLAINS NATURAL GAS / WAHPETON RATE PHASE-IN

Q. What is your understanding of the Company's rate phase-in proposal for Wahpeton?

A. The Company is requesting to phase in the rates for approximately 2,355 Wahpeton customers in less than two years. The phase-in includes moving customers from the Great Plains tariff to the Montana Dakota tariff at the conclusion of this rate case. In addition, the Company wants to convert the Great Plains Customers to a Montana-Dakota invoice one year after the implementation of final rates in this rate case. There are two separate elements to this change-over. The first element is the initial change of switching customers to a new rate schedule and a Montana-Dakota bill. The switch evidently involves providing the customer with a final bill under Great Plains followed by a new bill from Montana Dakota. The second element involves switching customers to new rate schedules. This switch can potentially lead to significant bill changes for some customers, even if they do not change their consumption. In addition, Great Plain's customers have already experienced a tariff change as a result of the Commission's approval of the interim rate increase.

Q. What is your understanding of the settlement in the prior rate case with regards to Great Plains?

A. The settlement in PU-17-490 and PU-17-075 contains the language shown below which I interpret to contain some latitude with regards to the interpretation of rate structures versus specific rates.

> The Parties agree that, if feasible, Great Plains will propose to role Great Plains' rate structure into Montana-Dakota utilities Co. ("Montana-Dakota") rate structure upon filing the next Montana-Dakota natural gas rate case in North Dakota." P. 3.

My perspective is that the Phase I rate changes for the residential and small commercial customers that eliminate the declining block structure for the distribution rate and switch from a monthly to daily customer charge are consistent with moving to the Montana-Dakota rate structure.

Q. Do you have any concerns regarding the change in billing and rate schedules?

A. I have two areas of potential concerns; first is customer confusion regarding the bill change. The second is the bill impacts for customers.

Q. How is the Company addressing potential customer confusion?

A. The Company has indicated that customers will receive an informational notice in their bill during the Phase-in process as well as a notice in their final Wahpeton bill. The Company is also considering additional customer communications, such as possible community meeting(s) and information on the Company's website.[18]

Q. Has the Company adequately addressed the potential customer confusion issue?

A. The Company noted that no customer education programs are in place or planned to be in place throughout the phase-in process. Additionally, the Community meetings may not occur due to pandemic restrictions. Potential customer confusion will ultimately come down to the clarity of the bill messages and the knowledge of Company personnel to field customer questions. I recommend the Company implement a feedback process to understand the clarity of the bill messages as well as implement a staff training program to ensure Company personnel are well-versed in the phase-in process mechanics.

Q. What rate changes are involved in switching customers to the Montana Dakota tariff?

A. In the first phase customers do not change their type of service: in other words, firm customers on Great Plains service conditions will remain firm service customers and likewise interruptible customers will remain on interruptible service. However, where there was originally one class of service for firm and one class of service for interruptible customers, there will now be two classes in each designation (63 or 73 and 76 or 86). In addition, the block rate structure will be replaced with a single block.

Q. What rate changes are involved in Phase II of the Company's proposal?

A. Residential and commercial customers on firm service will be split into Montana Dakota's rate schedules 63 and 73 respectively and non-residential interruptible customers on sales service will be split into rate schedules 76 and 86 respectively based upon their annual consumption. Likewise, interruptible transportation customers will be moved to Rate 83 or 84 depending on their annual consumption.

Q. Will there be rate impacts associated with the second phase?

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[18] Prefiled testimony Ms. Bosch p 7 lines 8 – 17.

A. Yes. While, the switch from Phase 1 to Phase II will be revenue neutral, customers may see rate changes as a result of the implementation of the new schedules. For example, under Phase I, rate schedules 63 and 73 have the same rates. Under Phase II, the residential customers fixed charge is increased, the small and large firm customers have different fixed charges and their fixed charges both increase as well. The changes are revenue neutral as a result of the decrease in the Distribution Delivery Charge.

Q. Will there be residential rate impacts associated with moving customers to Montanan-Dakota rates?

A. The Company's analysis indicates that 16% of the residential customers will have annual bill increases of over 15% due to implementation of the first phase and 5% having increases over 10% as a result of Phase II rates.[19] In Phase I it appears that the larger volume gas users have the largest bill increases as a result of eliminating the declining block rate schedule. In Phase II it is the small volume users that have the greater bill increase as a result of the increase in the daily basic charge from $0.25 / day to $0.333 / day. The basic charge increases are offset by a decrease in the distribution charge.

Q. What are the rate impacts on small commercial customers?

A. 22% of the small commercial customers will have rate increases over 15% in Phase I and 40% will have increases over 10% in Phase II.[20] The drivers of the rate increases are similar to the residential rate changes; elimination of the declining block structure in Phase I and the increase in the basic charge in Phase II.

Q. Are the Phase II residential and small commercial rate increases concerning?

A. The Phase II customer charge is on average $10.13 / month for a year-round residential customer and $15.21 / month for a small commercial customer. Based upon the customer cost from the cost of service study, that charge does not appear to be inconsistent with the Commission's preference expressed in PU-15-90 and the last rate case to recover fixed costs

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[19] Statement L p 24 - 25
[20] Statement L p 26 - 27

on a non-volumetric basis.[21] The increase in the customer charge does not concern me from a policy perspective, however, I note that this creates a likely third rate change, excluding the cost of gas, in two years and even small bill increases can potentially create hardships for residential customers on limited income and commercial customers struggling to survive.[22]

Q. How will the Phase II rate changes impact larger volume non-residential customers?

A. For large firm customers, the average fixed charge under Phase II is $30.42 / month, and the average fixed charge for Wahpeton's small and large interruptible gas service customers is $20.83 and $41.67 a month respectively. There is currently one Wahpeton interruptible transportation service customer who is served with a sperate contract and therefore is not impacted throughout Phase I and II of the rate change.

Q. Do you have any concerns with the implementation of Phase II?

A. Yes, under the Company's proposal Great Plains customers are expected to experience three rate changes with a two-year period. While I am supportive of moving the customers to higher customer charges to cover their share of fixed costs, that change does not have to happen prior to the next rate case given the historical frequency that Montana Dakota has come before this Commission for increases in general rates.

VI. OTHER RATE CHANGES

Q. What is the Company proposing to charge customers who request a manual meter read versus reading through AMR?

A. The company is proposing a new fee for manual meter reading; a charge of $26.05 / month for customers requesting a manual meter read with the additional provision that customers commit to manual reading for a minimum of one year.[23]

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[21] Findings of Fact, Conclusions of Law and Order, Case No. PU-17-295, Section 13, p 5.

[22] The first rate increase will be on January 1, 2021 based upon the interim rate relief approved by the Commission in its December 16, 2020. Order. The second rate increase will be later in 2021 based upon the Commission's findings in the current proceedings.

[23] NDPSC Volume 8, Rate 100 Section 15.

Q. Do you support the Company's proposed charge?

A. No, not in the form proposed by the Company. Based upon reviewing the Company's response to Advocacy Staff request 12.4, I agree that there are incremental costs for customers who request monthly manual meter reads. However, I also note that the Company has not identified the anticipated scope of the issue; i.e. the number of customers who would elect to opt-out of automated meter reading. (Currently there is only one customer in North Dakota requesting manual meter reads.)[24] I assume that customers who request manual reads have concerns that should be acknowledged and that many states accommodate customer requests to opt-out of automated meter reading. I am proposing an alternative pricing structure that includes a $100 enrollment fee and a monthly charge of $13.50 / month.

Q. Why are you proposing an enrollment charge and a lower monthly charge?

A. The enrollment charge is intended to discourage customers from requesting monthly manual reads as it creates an incremental cost that may ultimately be borne by the majority of customers who participate in automated meter reading. The lower monthly charge is intended to reduce the burden on customers who feel, for whatever reason, that they need to have manual meter reads.

Q. What is the basis for your proposed charge?

A. I started by thinking about what the charge if the pricing is structured so that for a one-year enrollment the same money is collected versus the Company's proposal. If the enrollment charge was $150 and the monthly charge was $13.50 / month then a customer who participates for longer than a year will have a lower cost versus the Company's proposal. I was concerned about the enrollment charge for a low-income / fixed-income customer so I selected $100; a number that I admit is subjective with regards to what creates a reasonable disincentive. I also note that the Company's estimate of $26.07 / manual meter read must have some assumption about the density of customers since clearly it did not cost that much prior to AMR. However, since the Company has provided no data on the number of customers who are / would request manual reads the true cost is not known.

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[24] Montana-Dakota response the Advocacy Staff DR. 14.2 (b)

Q. Do you recommend that the charge for manual meter reads be updated at the next rate case?

A. Yes, if the Commission is comfortable with the policy that customers should have the option to opt-out of automated meter reads, then the charges should be updated in the next rate case when there are actual data to review.

Q. Are there other utilities that have an enrollment charge and lower monthly charge?

A. Yes. I reviewed an article by the National Conference of State Legislatures on Smart Meter Opt-Out Policies.[25] The article indicates that one-time enrollment fees are common and that monthly fees range from $9 - $32.

VII. LINE EXENSIONS

Q. Is the Company proposing changes to the line extension policies?

A. Yes, the Company is proposing changing the Levelized Annual Revenue Requirement (LARR) in Schedule 120 and the Maximum Allowable Investment (MAI).

Q. Do you support the proposed changes to Rates 119 and 120?

A. Yes, understanding that the LARR and MAI will be updated to reflect the cost of capital approved in this proceeding.

Q. Are you proposing additional changes?

A. Yes, I am proposing a language change to Firm Gas Service Extension Policy Rate 120. The language in Section (A) 2 should be modified. The language "The Company may require customer or developer cost participation if the estimated capital expenditure is not cost justified." should be changed to "The Company **shall**….".

Q. Why are you proposing the wording change?

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[25] https://www.ncsl.org/research/energy/smart-meter-opt-out-policies.aspx, August 20, 2019.

A. One of the purposes of the line extension policy is to ensure that extending firm service to new customers is done when extending service is economical without shifting costs to existing customers. The use of the word "may" provides the Company discretion to extend the service when it is not economical per the calculation defined in the tariff. I note that in Rate 119, that applies to interruptible sales and transportation service, the word "shall" is used. My understanding that the Company's policy of granting allowances under Schedule 120 came to the attention of Advocacy Staff following the complaint of a developer. Based upon my discussions with Advocacy Staff and reviewing line extensions, it appears that the discretion currently allowed by the tariff may be one of the contributors to the requested rate increase.

Q. Did you review the historical proportional spend the Company incurred related to line extensions under rate 120?

A. Yes. I reviewed the Service Line and Main extensions under rate 120 with an in-service date between January 2015 through December 2019. The total Company spend for Main extensions over the 5-year period reviewed was $1,862,048, and the total amount that required a customer contribution was $6,433,021. This equates to the Company paying approximately 22% of the Main extension costs over the past 5-years. Two high cost projects in 2019 with relatively low customer contributions drive the relatively low customer contribution in 2019.

The Company noted that due to the system changes and upgrades, data for Service Line costs prior to 2018 is not available. The total Company spend for Service Lines in 2018 and 2019 was $245,536, and the total amount that required a customer contribution was $185,650. This equates to the Company paying approximately 57% of the Service Line costs over 2018-2019

Category	Year	# of Jobs	Total Cost	Billed to Customer	Company Spend in Proportion to Total Cost
Mains					
	2015	60	2,046,619	1,649,065	19%
	2016	37	1,473,018	984,408	33%
	2017	31	1,638,712	1,919,290	-17%
	2018	29	393,970	339,341	14%

	2019	32	2,742,750	1,540,917	44%
Total Mains		**189**	**8,295,069**	**6,433,021**	**22%**
Services					
	2018	88	228,166	114,524	50%
	2019	72	203,020	71,126	65%
Total Services		**160**	**431,186**	**185,650**	**57%**

VIII. ALLOCATION OF THE RATE INCREASE

Q. Have you reviewed the Company's proposal for allocation of the rate increase?

A. Yes, the Company is proposing to move rate classes close to parity but not moving all classes to parity upon considering customer impacts. Under the Company's proposed cost of service, the large interruptible class and the MAFB class would not get rate decreases as opposed to a scenario where all rate classes are brought to parity. While the overall rate increase for the residential class (including the commodity portion of the bill) is 12.5%, the proposed increase in the daily customer charge (which covers all other costs) is 30.2%. The following tables present the Company's requested revenue increase if allocated at parity for all customer classes and the requested revenue increase at the proposed allocation.

($ in Millions)	North Dakota	Residential	Small Firm General	Large Firm General	Air Force Delivery	Small Interruptible	Large Interruptible
Current Cost of Gas	73.32	34.39	8.05	25.68	1.19	2.12	1.89
Current Distribution Revenues	41.43	24.32	4.52	8.95	0.11	1.74	1.79
Distribution Revenue Increase at Parity	**8.97**	**8.40**	**0.82**	**0.64**	**0.03**	**0.03**	**-0.72**
Total Distribution Revenue	50.86	32.73	5.34	9.59	0.14	1.78	1.07
% Distribution Increase at Parity		*34.5%*	*18.2%*	*7.2%*	*26.5%*	*2.0%*	*-40.3%*
Company Proposal Distribution Revenue Increase	**8.97**	**7.34**	**0.82**	**0.64**	**0.03**	**0.10**	**0.04**
% Distribution Increase Company Proposal		*30.20%*	*18.20%*	*7.20%*	*26.50%*	*5.60%*	*2.00%*
% Overall Increase - Company Proposal	**7.80%**	**12.50%**	**6.60%**	**1.90%**	**2.30%**	**2.50%**	**1.00%**

Q. Did Mr. Amen calculate other approaches for the allocation of the rate increase?

A. Yes, Mr. Amen in Exhibit__(RJA-1) shows four alternative scenarios for allocating the rate increase; the first scenario brings all customer classes to parity, the second scenario allocated the entire rate increase in proportion to each rate classes revenues (excluding each rate classes non-gas and other operating revenues). The third scenario excluded a rate increase to those customer classes currently at or over parity. The final scenario, which is the one proposed by Mr. Amen, reflects that the percent increase to each customer classes revenues (excluding each rate classes non-gas and other operating revenues) should experience at least a 25% increase for all non-contracted customers.

Q. Are the Company's formulaic approaches the only options?

A. No, one can construct a broad range of rules for allocating the rate increase. The reality is that the development of rules and the choice of the preferred approach for allocating the rate increase is in-part results-driven. The targeted results can vary depending on one's view of the importance of moving the parity ratio to one for each rate class as well as one's perception of what is equitable and what could cause rate shock.

Q. Is it important to move each class to parity?

A. My opinion is that moving customers exactly to parity is not critical since the determination of parity depends on allocation of large amounts of joint costs and cost-of-service studies are a combination of art and science. To the extent that a Commission has confidence that the cost of service study is precise and accurate then adhering strictly to a parity target may be more of a priority. In this instance the Company and I have different views of how distribution costs should be allocated and hence will arrive at different parity ratios. As a result, I am more focused on directionally moving towards parity while considering the impact of the rate increase especially given the economic stress that customers may be feeling as a result of the COVID epidemic.

Q. What is your recommendation?

A. At a minimum, no class should get a rate decrease and the Company's proposal of allocating a minimum of 25% of the increase to each class is also reasonable. My recommendation is that maximum increase should factor in the total increase including the cost of gas. I recommend that the average rate increase for the residential class should be 10%. As a formula, the rate increase for the residential class should be held to two times the average rate increase subject to the 10% cap. I do not view this as a hard and fast rule that should be carried to future rate cases, but in recognition of the financial stress created by the COVID pandemic. Ms. Kivisto acknowledges:

> "We understand that many of our customers may be experience economic hardship resulting from the COVID-19 pandemic, and that the prospect of a rate increase may be difficult at this time."[26]

My concern is that these economic hardships will persist beyond the time that the proposed rates go into effect.

Q. Do you agree with the Company's proposed residential rate design?

A. I am aware of the Commission's preference for the fixed charge approach and I recognize that the distribution delivery costs are essentially fixed costs. However, I want to point out the inconsistency with the argument that there is a demand component to distribution delivery costs and that argument is used to allocate 70% of the distribution mains on a peak demand basis versus on a customer basis. From a rate-shock perspective I am concerned that the Company's proposed 30% increase in the residential distribution costs translates into a large rate increase for a small volume user. However, there are neither strict definitions for "rate shock", nor for what is "fair" and "equitable". Based upon the testimony of Advocacy Staff, it is my expectation that the Commission will not grant the full rate increase requested by Montana-Dakota. Under the assumption that the final rate increase to the residential class will be smaller than what was requested and more in line with Advocacy Staff's recommendations, I anticipate that allocating the full rate increase to the Basic Service Charge will be more acceptable.

[26] Prefiled direct testimony of Nicole Kivisto p 8, lines 5 – 7.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

JIM HEIDELL

DIRECTOR

Jim Heidell specializes in electric and gas utility regulation, distributed energy, 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

CLIENTS

- Riverstone Holdings
- Puget Sound Energy
- Solarcity
- Comision Federal de Electricidad
- North Dakota Public Service Commission

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.
- **Financial Analysis** – Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.
- **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.

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **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 of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.
- **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.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

Rebuttal of claims of economic damage associated with the cancellation of a water desalination project in Monterey California.

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.

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

Preparation of multiple Independent Market Expert Reports to support financing of community solar projects in Illinois, Maine, Massachusetts, New York, New Jersey, and Maryland.

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

California-American Water Company, a California Corporation; Monterey County Water Resources Agency, Plaintiffs, vs. Marina Cos Water District; RMC Water and Environment, a California Corporation; and DOES 1 through 10, inclusive, Defendants, Case No. CGC-15-546632. Report and Deposition on behalf of RMC Water and Environment addressing alleged economic damages as a result of a cancelled desalination project.

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 – Dakato Range Wind Project, Case No. PU-17-372.

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.

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **2020 Natural Gas Rate Increase** **Application**	**Case No. PU-20-379**

VERIFICATION

STATE OF ___Colorado________)
) ss.
COUNTY OF __Summit________)

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.

James A. Heidell

Subscribed and sworn to before me this 14th day of January 2021.

Notary Public
My Commission Expires: Jul 13, 2024

PRECIOUS YOUNG
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20204023980
MY COMMISSION EXPIRES JUL 13, 2024