**MONTANA-DAKOTA UTILITIES CO.**

**Before the North Dakota Public Service Commission**

**Case No. PU-22-194**

**Rebuttal Testimony**
**of**
**Ronald J. Amen**

**February 28, 2023**

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## I. INTRODUCTION AND SUMMARY

**Q. Please state your name and business address.**

A. My name is Ronald J. Amen, and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

**Q. On whose behalf are you appearing in this proceeding?**

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

**Q. Have you provided previous testimony in Case No. PU-22-194?**

A. Yes. I previously sponsored direct testimony in this proceeding.

**Q. Did you sponsor any exhibits or schedules supporting your direct testimony?**

A. I sponsored Statement K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Overall Bill Impact
- Exhibit No.____(RJA-2), Estimated Residential Bill Increases

**Q. Please briefly summarize the subject of your direct testimony and the topics covered therein.**

A. My direct testimony presented Montana-Dakota's Cost of Service Study ("COSS") and discussed its results. I also presented the various rate design proposals filed by Montana-Dakota in this proceeding. My direct testimony consisted of the following sections:

- Principles of Cost Allocation
- The Cost of Service Process
- Selection of Class Cost of Service for Montana-Dakota
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues

- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

**Q. Please summarize the purpose of your rebuttal testimony.**

A. I will address certain issues raised by the testimonies of AARP witness, Ronald Nelson; the Advocacy Staff of the North Dakota Public Service Commission ("Staff") witness, Dr. Marie Fagan; Marathon Petroleum Company LP ("Marathon") witness, Kavita Maini; and Walmart witness, Andrew D. Teague.

First, I will offer an opposing viewpoint and supporting factual evidence to address the issues raised by Mr. Nelson's proposed classification and allocation methodology under the "basic customer" approach and his critique of Montana-Dakota's use of its traditional minimum system analyses.

Second, in response to Staff witness Dr. Fagan, I will provide clarification regarding Montana-Dakota's distribution loss factors in this proceeding, as compared to those employed in Montana-Dakota's prior rate case, PU-16-666.

Third, I will comment on Marathon witness, Ms. Maini's preference for the use of class contributions to the four highest peaks in the test year ("4-CP") as the demand allocator for fixed production (non-renewable) plant, as opposed to the class contributions to the twelve coincident peaks ("12-CP"), used in the Company's COSS. I will also address Ms. Maini's critique of Montana-Dakota's traditional use of a flat kWh allocator for fuel and purchased power costs versus her preference for an "E8760" allocator to capture the variability of fuel costs and load by hour between weekday daytime hours compared to nighttime and weekend hours.

Fourth, I will discuss AARP witness Mr. Nelson's Class Revenue Allocation and his proposed Residential Rate Design, which is an outgrowth of his basic customer classification and allocation proposal.

Finally, I will address Walmart witness, Mr. Teague's recommendation regarding the General Electric Service Rate 30 Secondary ("Rate 30") rate design, under which Walmart's four retail stores and related facilities primarily receive electric service.

**Q. Are you sponsoring any exhibits or attachments to your rebuttal testimony?**

A. Yes. I am sponsoring the following exhibits, which was prepared by me or under my supervision and direction.

- Exhibit No.____(RJA-1R), Montana-Dakota's Line Loss Study
- Exhibit No.____(RJA-2R) Summary of Minimum System/Zero-Intercept Research
- Exhibit No.____(RJA-3R), MDU's Schedule of Planned Outages (2021)

## II. CUSTOMER COMPONENT OF THE DISTRIBUTION SYSTEM

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please summarize the methods by which a customer component of Montana-Dakota's investment in its electric distribution system was determined for classification purposes within the company's Cost of Service Study (COSS).**

A. As discussed in my direct testimony, the two most commonly used methods for determining the customer cost component of distribution system facilities consist of the following: 1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. The zero-intercept method determines the costs associated with zero loads by valuing the costs of all assets in an account and conducting regression analysis of cost on current-carrying capacity or demand rating to establish the cost of a zero-load system. The most commonly installed, minimum-sized unit of plant method classifies the costs of a minimum-size version of the utility's distribution system capable of connecting to all customers as customer-related, then classifies all remaining costs as demand-related. Each of the accounts (e.g., Account Nos. 364 – 367) are examined to identify the smallest, most commonly used type of pole, conductor, etc. The unit cost of this minimum-size plant is then multiplied by the total number of units of that plant type. A comparison with the value of all the assets in the account yields the minimum-sized result. For purposes of determining the customer component of distribution system facilities to be used in Montana-Dakota's COSS, both the zero-intercept and minimum system methods were employed and are widely accepted techniques for determining customer related costs in the utility industry. One of the more commonly accepted literary references relied upon when preparing embedded cost of service studies is the Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC").[1]

**Q. How has Montana-Dakota used the two methods to determine its minimum distribution system?**

A. As discussed in my direct testimony, Montana-Dakota uses the minimum-size method for Account Nos. 364 – 367 and the zero-intercept method to classify transformers (Account 368). The Company's method for Account Nos. 364 – 367 uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current

[1] Amen Direct, at 17:21-18:15.

replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. The one-mile-of-circuit approach constructs a realistic representation of a Montana-Dakota circuit under two scenarios and applies the standard minimum system logic that uses the smallest feasible equipment size to serve that circuit as an acceptable way to identify customer-driven cost. This approach has been used by Montana-Dakota in many prior cost of service studies in North Dakota and its three other jurisdictions.[2]

**Q. How does Montana-Dakota separate the customer and demand classification components for Account No. 368, line transformers?**

A. Montana-Dakota uses the zero-intercept approach for each of three types of transformers (single-phase and three-phase pad mount transformers, and single-phase line transformers). The weighted average of the three types yields the two classification components for the complete account.

**Q. Why does Montana-Dakota use the zero-intercept method for Account No. 368, but the minimum-size method for the other accounts described above?**

A. Line transformers are not readily included in the methodology based on the representative one mile of circuit (which is the basis for the minimum system). Line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis.[3]

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[2] Ibid, at 18:18 – 19:2

[3] Ibid, at 19:18 – 20:5.

## B. Position of The Parties

**Q. Please summarize the position of the AARP with respect to a proper COSS model construct for classification of Montana-Dakota's electric distribution system?**

A. AARP witness begins his cost of service testimony by stating that decision-makers (meaning regulators) should consider how economic incentives of utilities can impact assumptions within utility sponsored cost of service studies and these economic incentives may not always align with public policy goals and ratepayer interests, when evaluating cost of service modeling.[4] Mr. Nelson highlights two interrelated issues that can impact the utilities' "perspective" when conducting cost studies, the first issue being the price elasticity, or sensitivity, of demand and that variability of demand for electricity differs across customer groups; in other words, how much a consumer changes their electricity consumption given a change in its price. "This presents the utility with an incentive to shift subjective cost allocations in the cost of service study (and there are many in cost studies) to classes with less elastic and variable demand."[5] The second issue is provided by third-party services provided through technological improvements that can function as substitutes for utility services, where electric utilities have not faced competition on the distribution system. "[T]he presence of this competition impacts utility incentives in many ways, potentially prompting them to take actions to make their services more cost competitive through otherwise inefficient rate design changes."[6] Since the utility perspective is largely informed by its economic incentives, "when subjective determinations are made within a cost of service

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[4] Nelson Direct, at 6:15-20.
[5] Nelson Direct, at 7:13-15.
[6] Ibid, at 20-23.

study or rate design, utilities are likely to make assumptions that benefit their bottom line - as would any for profit business in a similar position."[7] Mr. Nelson believes this phenomenon to be especially problematic with regard to cost of service studies because of the numerous subjective assumptions involved in the process; and particularly the so-called subjective decisions made by Montana-Dakota. While not wishing to "demonize" the utility, Mr. Nelson's stated goal is to highlight for regulators the influence that these "perverse economic incentives" have on the perspectives a utility shares in regulatory proceedings and when it constructs cost of service models.[8]

**Q. Given Mr. Nelson's perspective on the influence of economic incentives on a utility cost of service study, please summarize his preference for the classification of Montana-Dakota's electric distribution system.**

A. Mr. Nelson advocates for a "Basic Customer" method for the classification of customer-related electric distribution plant; namely, services and meters. "According to the basic customer approach, only costs that can be traced to a specific customer should be assigned as customer costs, because those are the only costs that vary based on the number of customers in a class. Under this theory, the costs of the conductors and transformers cannot be attributed directly to a customer, because adding one customer to the system would not increase these costs. Instead, the basic customer approach recognizes that the distribution system is built to serve peak demand, and so its costs should be classified as demand related. The basic customer approach has been utilized by commissions to inform monthly customer charges for residential customers."[9]

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[7] Ibid, at 8:2-7.
[8] Ibid, at 10-16.
[9] Ibid, at 10:20 – 11:5.

**Q. Have other parties to this proceeding raised objections to Montana-Dakota's application of the minimum system and zero intercept methods for determining a customer component of its electric distribution system?**

A. No.

### C. Montana-Dakota's Rebuttal Position

**Q. In his introduction to cost of service studies, Mr. Nelson cautions regulators at some length about the perverse economic incentives for utilities to base assumptions and subjective decisions on impacts to the "bottom line" when constructing cost of service studies. Can you provide instances from your experience whereby a utility client requested that you pursue a particular cost of service construct that would preserve or enhance the client's bottom line?**

A. Emphatically no. In Section III of my direct testimony, I discuss the principle of cost causation and why it is important. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," which is another way of saying those who cause the costs should pay the costs.[10] I've adhered to that principal in every cost of service study conducted throughout my career as part of utility management and as an energy industry consultant. I note that Mr. Nelson provides no evidentiary support, authoritative sources, or examples to support his conclusions about price elasticity of demand across customer classes or the impact of third-party competitive services that are specific to Montana-Dakota's recovery of its costs of providing electric utility service or its bottom line.

**Q. How does one determine the factors that cause costs?**

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[10] Amen Direct, at 6:10 – 7:18.

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWh increases, does the cost of some input such as miles of conductor increase with more kWh? Since the miles of conductor do not change with kWh either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of that cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the electric distribution system.

**Q. If the concept of cost causation is as straightforward as you describe, why is there so much debate about the process?**

A. First, the art of performing cost of service studies is often driven, not by logical analysis of cost causation, but by the outcomes the party is seeking to accomplish through regulation. As a result, the cost analyst may not be driven by the engineering and operating realities of a utility's system but rather by the nature of the analyst's preferred outcomes. Typically, for cost of service advocates, the preferred outcome is a lower allocation of revenue requirements to the customer(s) represented by that party. Second, some analysts use the cost of service process as a means to promote a particular policy objective such as discouraging a use of a particular service or promoting the use of some other service. In some cases, it is as simple as the desire to capture benefits for some customer or group of customers at the expense of other customers. In any event, the result is always lower costs and therefore rates for the preferred group. The utility has no reason to favor one group over another and seeks to match cost causation with rates.

**Q. As part his support for the Basic Customer method of cost classification of distribution system equipment as 100% demand related, Mr. Nelson quotes two industry sources, Mr. Jim Lazar, currently affiliated with the Regulatory Assistance Project (often referred to by their logo, "RAP") and the distinguished regulatory economist (and often quoted) Alfred E. Kahn.[11] Are you familiar with these noteworthy industry professionals?**

A. Yes. I have known Jim Lazar since meeting in a 1993 rate case hearing before the Washington Utilities and Transportation Commission (WUTC). Mr. Lazar was representing the Public Counsel's Office of the state Attorney General, the consumer advocate in Washington. Jim has been a tireless advocate for the Basic Customer method as long as I have known him, and successful in gaining acceptance by the WUTC of the methodology for use in electric cost of service.

I am also familiar with the passage quoted by Mr. Nelson from the late Alfred Kahn's text, reprinted below.

> "the utility's readiness to serve on demand. This readiness to serve is made possible by the installation of *capacity* ... the fixed, capital costs…And the proper measure of that responsibility is the

[11] Nelson Direct, at 13:2-21.

> proportionate share of each customer in the total demand placed on the system at its peak."[12]

The beginning of the passage where this quote appears refers to a two-part tariff, generally credited to John Hopkinson (named after him as the "Hopkinson" rate), widely used to employ peak responsibility pricing for large-volume wholesale and industrial users. The first part, an energy or "running" charge, embodied the variable costs and charged on a per kWh basis. The second part, the demand or capacity charge, was a charge for the readiness to serve on demand. The Peak Responsibility ("PR") rates were historically applied only to bulk sales and not retail sales of electricity to households.

**Q. As part of his support for the Basic Customer method, Mr. Nelson points to RAP as a credible authority having performed significant analyses that evaluated the minimum system approach and the controversy associated with it.[13] Are you familiar with the RAP organization?**

A. Yes. RAP markets itself as an independent, global, non-governmental organization advancing policy innovation and thought leadership within the energy community. Published in 2020, RAP's *Electric Cost Allocation for a New Era, A Manual* is a comprehensive reference source covering all elements of cost allocation for electric utilities. However, the "Manual" was not peer reviewed and there are inherent biases of its authors and the financiers of RAP. I have reviewed the publication at some length as part of a client engagement where it was appended to testimony in a regulatory proceeding. Atrium researched publicly available

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[12] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 95 (1988) Vol. I.
[13] Nelson Direct, at 20:16-20.

information listed in **Table 1** on grantmakers to RAP via the Foundation Directory Online.[14]

**Table 1**

**Regulatory Assistance Project Grantmakers - Total Grants (2016-2020)**

| Regulatory Assistance Project Grantmakers | Grand Total |
|---|---|
| The William and Flora Hewlett Foundation | $ 8,600,000 |
| Energy Foundation China | 6,782,000 |
| Sea Change Foundation | 2,000,000 |
| Climate Works Foundation | 1,275,000 |
| Barr Foundation | 675,000 |
| The John Merck Fund | 400,000 |
| Robertson Foundation | 375,000 |
| The Heising-Simons Foundation | 350,000 |
| McKnight Foundation | 275,000 |
| Walton Family Foundation | 250,000 |

Based on our review, there is a consistent public policy position and goal of the financiers of this organization to support the expansion and adoption of clean energy and public policy that encourages distributed generation adoption.[15]

**Q. What guidance does the NARUC Electric Cost Allocation Manual ("NARUC Manual") provide with regard to the classification of distribution system plant?**

A. The NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The key conclusion to be drawn

[14] The data in Foundation Directory Online is compiled from IRS information returns (Forms 990 and 990-PF), grant-maker web sites, annual reports, printed application guidelines, the philanthropic press, and various other sources. https://fconline.foundationcenter.org/

[15] A review of the grantmakers websites and mission statements clearly demonstrate their public policy interests: https://hewlett.org/about-the-environment-programs-grantmaking-2 | https://www.efchina.org/Front-Page-en | https://www.seachange.org/ | https://www.climateworks.org/ | https://www.barrfoundation.org/climate | https://www.jmfund.org/program-areas/clean-energy/ | https://robertsonfoundation.org/index.html | https://www.hsfoundation.org/programs/climate-clean-energy/ | https://www.mcknight.org/programs/midwest-climate-energy/our-approach/ | https://www.waltonfamilyfoundation.org/

from the NARUC manual is, "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs."[16] In fact, the NARUC Manual does not even mention the sole allocation of upstream distribution facilities on demand as an alternative for classifying and allocating distribution plant.

**Q. Mr. Nelson cites two sources of information regarding utility commissions in the U.S. that use the Basic Customer and energy related approaches for classification of distribution system costs, a RAP estimate from 2000 of approximately 30 electric utilities, and a natural gas utility's unverified claim of 19 states in a rate proceeding (CIR. 2015).[17] Do you have similar information regarding the use of a minimum system or zero intercept approach to classifying electric and gas distribution system costs?**

A. Yes, but much more current and based on Atrium Economics' own research, a summary of which is in Exhibit No.____(RJA-2R). Based on our current experience with client engagements in multiple state jurisdictions and research, electric utilities in twenty-three states have adopted to varying degrees a customer component of the distribution system.

**Q. Mr. Nelson mentions a few states where the merits of the Basic Customer method have been discussed by regulatory commissions.[18] Do you have first-hand knowledge of the minimum system study and the recognition of a**

[16] National Association of Regulatory Utility Commissioners, "Electric Utility Cost Allocation Manual," 1992 at 90.
[17] Nelson Direct, at 14:3-9, and footnotes.
[18] Nelson Direct, at 15:3-18.

**customer component of distribution facilities has been consistently used and approved by a state commission?**

A. Yes. An Atrium client in Indiana, NIPSCO Electric & Gas, has relied on this method in its several recent rate cases, and my Atrium colleague, Mr. John Taylor, developed and testified to these studies in their 2010 case (Cause No. 43969). He also developed and sponsored direct testimony in support of minimum system studies for Indianapolis Power and Light in their 2015 case (Cause No. 44576). In IPL's 2015 case the Commission in their final order stated:

> "For the allocation of distribution plant costs, we are not persuaded that none of the costs should be allocated based on the number of customers. The number of customers and their dispersion across a service territory create costs that can be independent of the demand of those customers. As both factors are cost drivers, and IPL has reasonably supported a reasonable delineation of the factors, we find its distribution cost allocation methodology reasonable.[19]

**Q. Mr. Nelson indicated that Montana-Dakota did not adequately justify its decision to base its minimum system study on the minimum size method, rather than the zero-intercept method, for FERC accounts 364-367. Can you address this matter?**

A. Yes. Mr. Nelson references a Montana-Dakota response to AARP Data Request 1-3(d). Attachment B to the response contained an Excel workbook that supported the minimum system study but upon further review, was missing the underlying source data. Had the data been included, it may have been self-evident why it was not conducive to a zero-intercept analysis. Montana-Dakota uses a mass asset

[19] Indiana Utility Regulatory Commission, Final Order dated March 16, 2016. Cause No. 44576, Indianapolis Power and Light 2015 base rate proceeding at page 66.

plant accounting approach that does not contain the detailed vintage data for poles and conductor (e.g., size, type length, vintage year) that would be needed for the zero-intercept analysis; only account balances were available. Therefore, the minimum system study used geographic information system ("GIS") data for recent construction projects, along with cost information for materials, direct labor and labor loadings, contractors, transportation, construction equipment, and capitalized administrative costs to derive the underground and overhead conductor, and poles elements of the "minimum mile" analysis in the workpapers for the minimum system study. It was not a subjective decision to <u>not</u> use the zero-intercept analysis.

**Q. Mr. Nelson makes the claim that Montana-Dakota "contradicted cost causation theory by including primary distribution system components in its minimum system study, neglecting to follow the instructions of the NARUC Electric Manual."[20] Please address this issue.**

A. This issue amounts to a nomenclature difference. Montana-Dakota classifies all conductor upstream of the connection to the line transformer as Primary. Most of the poles in the distribution system carry multiple conductors, both single and three phase, and different voltage levels. Normal operating voltage is 12.47/7.2 kV (not high voltage). The only conductor classified as Secondary is the line from the pole to the transformer and from there to the service drops. Secondary voltage downstream of the transformer is 120V to 240V. The NARUC Manual is not used as a guide by electric utility engineers on how they should classify their distribution infrastructure.

[20] Nelson Direct, at 19:9-13.

**Q. Mr. Nelson asserts the Minimum System method "requires the analyst to create a hypothetical, no-capacity system something that is not real and not directly based on system characteristics. To create this imaginary minimum distribution system, analysts must make *numerous subjective assumptions* that oversimplify system engineering and assign costs based on questionable cost causative principles."**

A. The terms *hypothetical* is overused in this context and *imaginary* is grossly inappropriate. Montana-Dakota's distribution engineering personnel were consulted to gain an understanding of the smallest standard size of facilities used in the electric distribution system. They compiled the underlying data from real construction projects, adhering to engineering standards and practices. As described in my direct testimony, the Company uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. The one-mile-of-circuit approach is a realistic representation of a Montana-Dakota circuit under two scenarios and applies the standard minimum system logic that uses the smallest feasible equipment size to serve that circuit as an acceptable way to identify customer-driven cost. Montana-Dakota's approach of creating a one-mile circuit is a realistic proxy for circuits in Montana-Dakota's service territory.[21]

A minimum-size distribution system, by definition, must have some capability to carry load. The fact that some equipment in the Company's minimum-

[21] Amen Direct, at 18:18 – 19:10.

size system has some nominal capability to carry load provides no basis for rejecting the minimum size system study. Where larger capacity equipment is installed, the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers. The objective of the Minimum System analysis is to identify an appropriate minimum-size set of distribution plant components that is tailored to the Montana-Dakota distribution system, not some hypothetical model applicable to an imaginary utility system.

**Q. Mr. Nelson claims that Montana-Dakota did not follow the instructions in the NARUC manual by using current cost when conducting a minimum system or zero-intercept study, because NARUC instructs that the average installed book cost should be used.[22] Is this a valid criticism?**

A. No. The "book cost" quoted by Mr. Nelson from the NARUC manual means that a fully loaded cost (e.g., including labor, equipment costs, restoration costs, and capitalized overheads) should be used in the analyses rather than just material cost. It does not preclude the indexing of installed costs to ensure that all the vintage costs from years of history are evaluated on a level cost comparative basis. Failure to do so assumes that the nature of the distribution system has not changed over time and the relationship between the costs of the material, labor and other construction costs have not changed over time. Both of these assumptions are false. It has become a widely accepted practice to index plant costs to enable just such an apples-to apples cost comparison, both for purposes of a minimum system or zero-intercept analysis. Commentary by RAP, which Mr. Nelson cites as a

[22] Nelson Direct, at 17:7-17.

"credible authority,"[23] in its publication, *Electric Cost Allocation for a New ERA*, recognizes the use of indexing costs of installed units of plant (i.e., current dollars) in its description of the minimum system method:

> "The minimum system method attempts to calculate the cost (*in constant dollars*) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related." [24] [Emphasis added]

**Q. Are there other authoritative sources on the topic of the zero-intercept analysis for the purpose of determining the customer component of utility distribution facilities?**

A. Yes. The Electric Utility Cost Allocation Manual, by John J. Doran, et. al., provides the following discussion of the zero-intercept method in Chapter VI B., "Two Methods for Determining Customer Components of Distribution Facilities:"

> "The minimum-intercept methods described in this chapter are based on average installed book cost of plant items. Because of inflation, which is generally reflected in larger size equipment, a rational minimum intercept cost may not be obtained where desired. However, the use of reproduction costs for each size will eliminate the distortion caused by inflation. A trend factor must then be used to reduce the minimum intercept from reproduction cost to average book value level. When data for its calculation can be obtained, the

[23] Ibid, at 20:14.

[24] See Jim Lazar, Paul Chernick and William Marcus, The Regulatory Assistance Project, *Electric Cost Allocation for a New Era, A Manual*, at 149.

minimum-intercept method is recommended for use over the minimum-size method."[25] [emphasis added]

**Q. Mr. Nelson criticized the Company's zero-intercept analysis for transformers based on NARUC instructions that only single-phase sizes up to and including 50 kVA should be used in developing the customer component and Company's decision to include in its calculation of customer costs transformers that exceed NARUC specifications inflates customer-related costs. Please address Mr. Nelson's concern.**

A. While there is room for disagreement with NARUC on this topic, based on the very limited sample size at </= 50 kVa (limited data points or degrees of freedom) for regression purposes, and the fact that the economies of scale from three-phase transformers (6x customers served over a single-phase transformer, which is reflected in the allocation) are ignored, the zero-intercept analysis was re-run under the NARUC parameters. The resulting customer component impact was negligible, less than 5%. The resulting cost per residential customer, per month was $.18, and does not provide a rationale for rejecting a customer component for transformers.

**Q. With Mr. Nelson's rejection of the minimum system and zero-intercept methods for classification and allocation of distribution plant, are there detrimental impacts to certain customer classes from his use of a 100 percent demand classification and allocation of distribution plant?**

[25] Electric Utility Cost Allocation Manual, John L. Doran, Frederick M. Hoppe, Robert Koger, William W. Lindsay, published by the National Association of Regulatory Commissioners (1973), page 56. This text was later given attribution by the head of the task force assembled by the NARUC Staff Subcommittees on Electricity and Economics in February 1985, to compile revisions and additions to the original manual. Among the objectives included in the Preface of the manual published by NARUC in 1992 was the following: "The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons." [emphasis added]

A. Yes. The impact of the 100% demand classification of poles, conductor and transformers is the allocation of more distribution costs to larger customers who may not even use any of the smaller facilities allocated to them through his method. There are substantial economies of scale for all sizes of transformers, overhead and underground conductor, and poles. In each case, the cost per kVA of industrial transformers is below the cost for every size of residential transformer. Some industrial transformers may be even lower cost per kVA than the lowest cost, single phase transformers used for residential customers. Using a demand allocation factor alone implicitly makes the incorrect assumption that the cost of transformer capacity is the same for all classes; it is not. By allocating the cost of transformers only on the demand, all the economies of scale of transformer costs are unfairly and incorrectly allocated to the residential class.

By classifying plant between customer and demand, the residential class receives a higher weighting of transformer costs consistent with cost causation, since the unit costs per kVA for residential transformers is higher and they use many more transformers than other classes of customers. Similar economies of scale occur for other distribution accounts, with the result that without the minimum system component, costs are significantly under-allocated to the residential class and over-allocated to larger customers with higher demands who use far less of the distribution assets than residential customers. Since scale economies apply across all components of the minimum system, including conductor and poles, the same conclusion applies to the other distribution accounts. For conductors, larger customers are typically located closer to substations than residential customers and therefore require fewer miles of conductor. The demand allocator significantly over-allocates distribution lines to larger customers, which does not consider the lower unit cost per kVA of line capacity to serve these customers. In summary, absent the use of the minimum system, the distribution costs to serve smaller customers are under-allocated and similar costs to serve larger load customers are over-allocated.

**Q. Are there other authoritative sources that support the recognition of the customer component of upstream distribution facilities?**

A. Yes. Dr. James Suelflow writes in his treatise, Public Utility Accounting: Theory and Practice, published by the Institute of Public Utilities at Michigan State University:

> "… distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."

Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer premises. This is not a new concept. Writing in 1900, Henry L. Doherty formulated a three-part rate consisting of a customer charge, demand charge and energy charge. In the original paper, "Equitable, Uniform and Competitive Rates" Doherty defined the minimum costs associated with "readiness to serve," and specifically included not only the components of the basic customer costs, but the cost of poles and conductors, with 50% classified to the customer component and 50% to the demand component. His analysis also included overhead loaders in the cost-per-customer.

In addition, Professor Bonbright in the Principles of Public Utility Rates[26] states that "customer costs incurred to serve a customer are invariant with respect to consumption. They are the costs incurred to serve a customer even if the

[26] Principles of Public Utility Rates, Second Edition, Page 491 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

customer does not use the service at all. The most obvious examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing, and accounting, and a portion of the distribution system." [27] (Emphasis added). Finally, Professor Bonbright states that "in actual practice the vast majority of utilities utilized some form of minimum system to classify costs, which is in line with FERC accounts." [28]

## III. MONTANA-DAKOTA'S LINE LOSS STUDY

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please address whether Montana-Dakota's most recent line loss study was discussed in your direct testimony?**

A. Montana-Dakota's line loss study was not a topic in my direct testimony. The study was part of the workpapers supporting the COSS, a summary of which was presented in the Statement K workpapers, Loss Factor Calculation, page 19 of 51.

### B. Position of Public Advocacy Staff

**Q. Please summarize the issue raised by Public Advocacy Staff witness Dr. Fagan regarding the loss factors used in the COSS.**

A. Staff witness, Dr. Fagan, compared the loss factors from the Loss Factor Calculation summary from a Statement K workpaper to those from the Company's prior case, PU-16-666, and noticed some significant differences. She discussed those differences in her direct testimony. Due to the level of changes in a couple of categories – Distribution Primary Lines loss factors increased and Distribution Service Lines loss factors actually decreased – and unable to reconcile those

[27] Ibid, Page 401.
[28] Ibid, Page 492.

differences from the workpaper, Dr. Fagan recommended the distribution line losses from PU-16-666 be retained.

### C. Montana-Dakota's Response

**Q. Has Montana-Dakota performed an updated line loss study that supports the line loss factors presented in the Loss Factor Calculation summary in the Statement K workpapers?**

A. Yes. The 2022 line loss study was not included with the Company's direct case filing, nor was it requested in a data request from Staff. Nevertheless, accompanying my rebuttal testimony as Exhibit No.____(RJA-R1) is a three-page schedule titled, "Loss Data for Substations, Distribution Transformers and Distribution Lines," which supports the loss factors in the Loss Factor Calculation summary from the Statement K workpapers. The full line loss study is available upon request.

**Q. Please discuss the process and analysis tools used by Montana-Dakota for the line loss study.**

A. Montana-Dakota uses the CYMEDIST Distribution System Analysis tool to calculate its distribution line feeder loading and feeder losses. CYMEDIST is a distribution system analysis software tool to model and analyze electric distribution systems. Montana-Dakota uses its Geographic Information System ("GIS") electric distribution data, which is exported into CYMEDIST for analysis. The CYMEDIST tool has been used for both the 2016 and 2022 line loss studies.

**Q. Please discuss the actions taken by Montana-Dakota since the 2016 to improve the accuracy of the line loss study.**

A. Changes have been made to the GIS data since 2016 that has resulted in a more accurate distribution model for analysis in CYMEDIST. Between 2016 and 2022 the following action were taken to provide more accurate and reliable data:

1. Montana-Dakota contracted with Davey Resources Group, Inc. to do a facility field audit for comparison to the GIS data. Corrections were made in the GIS system to improve the accuracy of distribution system facilities data. This provided a more accurate distribution model for CYMEDIST analysis. Improvements were made in the following categories of distribution system facilities:
   - Phasing Feeder
   - Conductor Sizes (Effects Line Losses)
   - Distribution Transformer – Customer Connection Accuracy
   - Feeder Configuration - Feed Open Points (Primary and Secondary Voltages)
2. Montana-Dakota also cleaned the GIS data to have accurate customer loading (i.e., usage) connected to the feeders. Therefore, the 2022 CYMEDIST loading analysis has higher customer loading connected to the distribution feeders. With higher customer loading modeled on the distribution feeders, there will be higher loading losses calculated.

## IV. ALLOCATION OF PRODUCTION PLANT

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please summarize your testimony related to the selection of the 12-CP allocation method for production and transmission costs.**

A. As discussed in my direct testimony, the Federal Energy Regulatory Commission ("FERC"), the body that regulates the wholesale rates of electricity in interstate commerce, has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[29] FERC will allow utilities to propose an alternative to 12 CP, but the utility must demonstrate that such alternative is consistent with the utility's system planning and would not result in an over-collection of the utility's revenue requirement. In evaluating such determinations, FERC uses the three peak ratios test established in *Golden Spread Electric Coop., Inc.*, 123 FERC ¶ 61,047 at 61,249 (2008):

Test No. 1 – On and Off-Peak Test: This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

Test No. 2 – Low-to-Annual Peak Test: Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

Test No. 3 – Average to Annual Peak Test: Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.

I applied FERC's three peak ratios test to Montana-Dakota's North Dakota load data (2014-2021). Montana-Dakota meets all three FERC tests for using 12 CP for five out of the eight years. For 2015 and 2020 Montana-Dakota meets two of the three tests, and for 2016 Montana-Dakota meets one of the three tests. Therefore,

[29] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

based on the FERC three peak ratio test, it is appropriate to use the 12 CP allocation method for production and transmission demand-related costs on Montana-Dakota system. Table 2 in my direct testimony shows the results of the Montana-Dakota's FERC 12-CP test.[30]

### B. Position of Marathon Petroleum Company

**Q. Please summarize the viewpoint of Marathon regarding the allocation of fixed production plant-related costs.**

A. Marathon witness, Ms. Maini, states that production plant must be sized to meet the maximum load or demand imposed on these production facilities, and that an alternative allocator can be used to reflect the cost causative characteristics. Ms. Maini charted the monthly system peaks as a percentage of the overall annual peak for the test year and noted the four monthly peaks within 96% of the annual system peak. Based on this review, Ms. Maini determined that it would be appropriate to consider class contributions to monthly demands for all months with 10% of the system peak, as generation capacity is sized to reliably meet the highest peak demands. Ms. Maini concluded that the class contributions to the four months that fell within the 10% threshold (February, June, July, and August) be used to construct a 4-CP demand allocator to replace the Company's 12-CP demand allocator for fixed production (non-renewable) plant in the Company's COSS model.[31]

### C. Montana-Dakota's Response

**Q. Please respond to Marathon's request for a change to the allocation method for fixed production plant-related costs.**

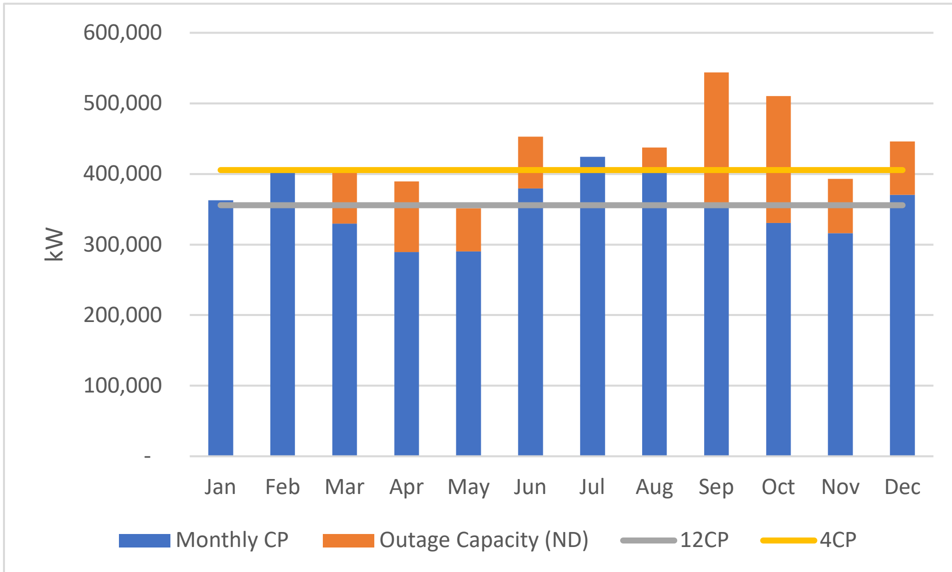
[30] Amen Direct, at 8:16 – 10:3.
[31] Maini Direct, at 16:281 – 17:295.

A. As I detailed in my direct testimony, it is appropriate to continue use of the 12-CP allocation method for production and transmission demand-related costs on Montana-Dakota's system. The 12-CP method was developed in part recognizing a review of the total demand on system capacity, not simply the system load demand. This is an important distinction because load is not the only demand placed on capacity. Generation capacity must also be maintained and based on certain conditions that prevent it from being fully available to serve load. Unplanned outages also place a demand on the available capacity. Thus the demand on system capacity is the sum of load demand to serve customers, the scheduled outage demand for maintenance, the forced outage demand for unplanned outages and the demand that occurs because of weather or operating issues that limit capacity to less than the full output of the generation capacity resources. Based on the full demand on capacity, the appropriate 12-CP allocation factor reflects cost causation for the system based on all of the operating characteristics of the system.

**Q. Please provide an example that illustrates the additional demand on the system from the factors you just described.**

A. Figure 1 shows the total monthly system demand on capacity resources, including planned outages, in a bar chart, with similar format to that provided in Ms. Maini's direct testimony, illustrates the total demand on capacity for the system based on the maximum demand occurring in each month of the year. The lines on the graph show the 4-CP and the 12-CP. As seen on the chart, when unavailable resources in the shoulder months are considered, the 12-CP is a more appropriate measure of demand allocation for MDU. Exhibit No.____(RJA-3R), shows MDU's schedule of planned outages for 2021.

**Figure 1: Monthly CP with Outage Capacity**




As illustrated in Figure 1, when added to the load demand, limits on available capacity such as scheduled maintenance, forced outages and unit deratings, the monthly demands flatten out because maintenance is scheduled in low use months. Since the demand data for this illustration comes from the test year, the actual system peak may also change with weather during a particular calendar year. Typically, unit deratings occur in the summer and would add to the peak load in those months. Forced outage rates vary and as noted above, maintenance is scheduled in spring and fall months, as shown in Figure 1. Based on these facts, peak total demand falls in a narrower band for all 12 months. Therefore, I continue to support Montana-Dakota’s use of the 12-CP method for allocation of production and transmission demand-related costs on its system.

## V. ALLOCATION OF FUEL AND PURCHASED POWER

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please describe Montana-Dakota's treatment of fuel and purchased power in the COSS.**

A. As described in my direct testimony, fuel and purchased power expenses are allocated on energy at generation, as are certain fuel related O&M costs. Purchased power capacity also has a demand component, which is allocated on 12-CP. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, rate base items like provision for pension and benefits and post retirement costs are allocated on O&M excluding fuel and purchased power.[32]

### B. Position of Marathon Petroleum Company

**Q. Please summarize the viewpoint of Marathon regarding the allocation of fuel and purchased power energy costs.**

A. Marathon witness, Ms. Maini, states that Montana-Dakota's flat kWh allocator for fuel and purchased power energy costs fails to recognize hourly energy cost and load variations. Fuel costs vary by the hour and are typically higher in the week daytime hours compared to nighttime and weekend hours. She provides examples from Otter Tail Power Company and Xcel Energy of the use of an E8760 allocator to allocate all costs classified as energy related. To illustrate the impact of varying fuel costs by peak and off-peak hours, Ms. Maini provides energy adjustment ratios by class from Otter Tail Power Company's Energy Adjustment Rider. The ratios

[32] Amen Direct, at 23:11-18.

imply that classes with high load factors have a ratio less than 1.00 due to consuming more energy in off-peak hours when prices are lower. A ratio less than 1.00 means that below system average costs should be allocated to a high load factor class. Therefore, Ms. Maini believes Montana-Dakota's flat energy allocator is likely over allocating energy costs to high load factor classes and recommends that Montana-Dakota be required to develop and introduce an E8760 allocator for recovery of fuel costs through the fuel and purchased power rider. She states that the E8760 be effective with final rates in this case.[33]

### C. Montana-Dakota's Response

**Q. Please comment on Ms. Maini's discussion of the cost causative aspects of moving from a flat kWh allocator for fuel and purchased power energy costs to a E8760 allocation method.**

A. Ms. Maini's comments are well-taken. I concur with her observations, based on the illustration from Otter Tail Power Company, of the potential cost impact on high load factor customer classes from not recognizing the variation in hourly energy related fuel and purchased power costs. However, I am hesitant to suggest that the investigation of such a conversion from the flat kWh allocation method to the E8760 method during the remaining course of this proceeding would be possible. There are considerations related to the current structure of Montana-Dakota's load study data and implications for the Company's jurisdictional allocations. Montana-Dakota has indicated to me that the Company would be willing to investigate the development of the E8760 allocation method, prepare an evaluation of its application, and proposal for its next electric North Dakota general rate case, for allocation of the Company's fuel and purchased power energy costs.

[33] Maini Direct, at 19:341 – 20:357.

## VI. CLASS REVENUE APPORTIONMENT

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please summarize how the Company's proposed revenue increase was allocated to customer classes?**

A. As described in my direct testimony, the apportionment of revenues among customer classes consisted of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were evaluated for Montana-Dakota's customer classes in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations.[34]

**Q. What was the result of this process?**

A. In consultation with Montana-Dakota, I concluded the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all its customer classes. The Company's revenue increase proposal is designed to move each customer class's revenue to cost ratio toward parity while establishing a minimum level of increase to customer classes that are currently above parity. For the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve the class's revenue to cost ratio from 0.73 to 0.88.

The Small General Service (0.82), Large General Service Primary (0.88), and Space Heating (0.87) customers classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.513%. The proposed revenue

[34] Amen Direct, at 30:14 – 32:9.

increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity.

The maximum margin revenue increase of 35% was proposed for the Irrigation Service (0.34), Small Municipal Service (0.64), and Municipal Pumping Service Primary (0.73) customer classes. The Special Contract customers were limited to the same revenue increase as the Large General Service Primary class, or 13.239%.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue <u>decreases</u> in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), it was decided to refrain from revenue reductions. The proposed minimum revenue adjustments of 1/3 of the system average increase (4.634%) to eligible customers, will mean these classes will be slightly higher than their current parity ratio levels relative to unity.

The allocation of the total revenue increase of $17,539,519 to the respective rate schedules is presented in Statement L, page 2. The target revenue increase as a percentage of total class revenues, excluding fuel costs, range from 15.9% to Residential, 17.4% to Small General, 4.8% to Large General, 6.9% to Municipal Lighting, 10.8% to Municipal Pumping, and 3.5% to Outdoor Lighting. [35]

### B. Position of AARP

**Q. Please summarize AARP's proposed revenue increase allocation to customer classes?**

[35] Ibid, at 32:11 – 34:21.

A. Under AARP witness Mr. Nelson's revenue allocation approach, fewer costs would be allocated to the Residential class using his basic customer approach to cost of service. This would lessen the amount by which the cost of service exceeds existing revenues from the class. He recommended limiting the increase to any customer class to 20%. He asserts that the maximum class increase of 35% would create "rate shock." Increases to classes above parity should be limited to 90% of the system average or 12.5%.[36]

### C. Position of Walmart

**Q. What was Walmart's position regarding Montana-Dakota's class revenue apportionment?**

A. Walmart did not oppose the Company's proposed revenue allocation. If the Commission approves a revenue requirement lower than that proposed by the Company, the Commission should begin with the revenue allocation proposed by Montana-Dakota and use the reduction in revenue requirement to move classes closer to cost of service.

### D. Position of Marathon

**Q. Is Marathon witness, Ms. Maini recommending any changes to the Company's proposed revenue allocation to the major classes such as residential, small general service, large general service, municipal lighting, municipal pumping, or lighting classes?**

A. No. Ms. Maini states that while she could recommend an alternative revenue allocation, based on the 4-CP COSS results, in order to narrow the differences in the case, she is not recommending revenue allocation changes to the major

[36] Nelson Direct, 28:12 – 21.

classes as proposed by the Company. To maintain Montana-Dakota's proposed revenue allocation approach, she calculated the resulting percent class revenue responsibility share excluding fuel after applying the proposed increase. Ms. Maini suggests these shares can be applied to the final total revenue requirement excluding fuel, and the costs proposed to be recovered through the Generation Resource Recovery Rider.

### E. Montana-Dakota's Rebuttal Position

**Q. Is Montana-Dakota proposing any revenue requirement revisions or changes to class revenue apportionment in rebuttal testimony?**

A. No.

**Q. Have you a response to Mr. Nelson's proposed revenue allocation to Montana-Dakota's respective customer classes?**

A. Given that the underlying basis for Mr. Nelson's proposed class revenue apportionment is COSS results under his basic customer method of cost allocation, I recommend that the Commission reject it.

**Q. Did Mr. Nelson provide a common definition of rate shock or what circumstances give rise to it?**

A. No. Apparently it is somewhere between 20% and 35% margin revenue increase.

**Q. Do you accept Mr. Nelson's assertion that the Company's proposed margin increase of 35% to the three rate classes receiving such an increase result in "rate shock"?**

A. No. In my experience, the term "rate shock" in the utility industry has been a convenient phrase to use as rationale for opposing large over-all utility revenue increases. Its use is often controversial and rarely defined in terms of numerical boundaries. Within the context of cost allocation and rate design, some would argue that strict adherence to cost causation in setting class revenue responsibility can result in significant rate differences for many customers, causing adverse and disruptive impacts on customers; and therefore, rate shock. It would not be in the best interest of Montana-Dakota to propose changes to its current rates that would cause such adverse and disruptive impacts on its customers. The recommended revenue increases to the Irrigation Rate 25 (0.34 R:C ratio) of 22.6%, Small Municipal Rate 40 (0.64 R:C ratio) of 25.9%, and Municipal Pumping Rate 48 (0.73 R:C ratio) of 10.8%, under the Company's proposed revenue requirement should not be considered rate shock.

## VII. RESIDENTIAL RATE DESIGN

### A. Montana-Dakota's Presentation in Direct Testimony

**Q. Please summarize how the Company's residential class rate design proposal?**

A. Montana-Dakota has proposed to adjust the Basic Service Charges to better reflect the underlying costs of providing basic customer service for its customers based on the cost per customer component identified in the Company's embedded class cost of service study. The Basic Service Charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the Basic Service Charge in order to minimize intra-class subsidies and provide customers with the appropriate economic price signals. The Basic Service Charge under Residential Electric Service Rate 10 is proposed at $0.67 per day which reflects an average monthly charge of $20.38, an increase of approximately $6.39 per month from the currently effective charge.

### B. Position of AARP

**Q. Please summarize the position of AARP for the Company's Residential rate design?**

A. AARP witness Mr. Nelson disagrees with Montana-Dakota's proposed residential rate design for the following reasons. First, the justification for the increased charge is directly related to the results of the Company's minimum system study. Second, high customer charges harm customers, including low-usage and low- income customers as well as those investing in energy efficiency. Third, the Company's justification for its proposed customer charge increase lacks theoretical and analytical support. Mr. Nelson asserts that these concerns have become increasingly important given the evolving power mix in the MISO region, including North Dakota, which in contrast to MDU's proposal to increase fixed charges, will require a greater emphasis placed on volumetric charges to reflect the temporal (i.e., time-based) value of energy and demand.

**Q. What is AARP's Residential rate design proposal?**

A. Mr. Nelson recommends the Commission reject the Company's proposal to significantly increase the residential basic service charge and maintain the current charge for residential customers.

### C. Montana-Dakota's Rebuttal Position

**Q. Mr. Nelson discusses the evolving power grid at some length, including example from the Midwest System Operator ("MISO"), and suggests that changes on the power grid are relevant to rate design. Do you agree?**

A. Yes. I just disagree with his proffered solutions. While "the growing need to recognize the timing of peaks elevates the importance of appropriately allocating costs that vary with demand as being demand related" is appropriate, "[D]oing so may increase time-varying volumetric cost recovery"[37] is only appropriate if the costs are variable; that is, the costs vary directly with kWh, and are therefore avoidable. Demand related fixed costs should be recovered in demand based kW fixed charges, both for cost recovery and providing the proper price signal to customers.

**Q. Are there time-varying rates that are non-volumetric demand based rates.**

A. Yes. My colleagues and I have assisted several clients on projects involving time-varying demand charges. Some examples include:

- A time-varying demand charge for a tariff serving on-route electric transit bus charging stations for the transit authorities of Lexington and Louisville, KY (Louisville Gas & Electric).
- Developed a TOU rate design model, analyzing the time-varying components of the transmission, generation, and distribution costs, including time-varying demand charge rate options for large industrial customers (Liberty Utilities, Empire District Electric)
- Developed a new cost of service customer class for residential distributed generation (roof-top solar) customers and a corresponding three-part rate, including a demand charge and volumetric charge based on avoided energy costs (Westar Energy, now Evergy)

**Q. Mr. Nelson states, "The costs that the Company considers "fixed" do not fit its own definition of fixed costs. According to the Company, "fixed costs include all costs that do not vary with the amount of energy 'consumed by customers." As previously stated, however, costs in FERC Accounts 364-368**

[37] Nelson Direct, at 33:1-4.

**vary with demand (peak energy consumed), and thus do not align with the Company's own definition of fixed costs."**[38]

A. Here Mr. Nelson makes no distinction between demand based costs, the fixed cost of system capacity, with energy-related costs that directly vary with kWh usage. He offers an example of a transformer that needs replacement, "assuming that once installed, equipment will not need to be replaced due to <u>capacity</u> overload. This assumption is unsupported and untrue for some of the equipment deemed fixed, such as transformers."[39] [emphasis added] All electric utility plant and equipment need to be replaced eventually. In Mr. Nelson's *imaginary* electric utility world all costs, other than those that reside in his Basic Customer method, seem to be variable, whether demand or energy related. This viewpoint is apparently shared with that of RAP, the organization he references elsewhere in the direct testimony that I previously addressed. The following table, in Figure 2 below, is from RAP's *Electric Cost Allocation for a New Era, A Manual*.[40]

[38] Ibid, at 41:3-7.
[39] Ibid, at 9-11.
[40] See Jim Lazar, Paul Chernick and William Marcus, The Regulatory Assistance Project, *Electric Cost Allocation for a New Era, A Manual*, at 74.

## Figure 2: Comparison of Cost of Service Study Approaches

Table 9. Results of two illustrative embedded cost of service study approaches

| | | Legacy study: Peak responsibility/minimum system | | | Modern study: Base-peak/basic customer | | |
|---|---|---|---|---|---|---|---|
| **Cost category** | **Revenue requirement** | **Allocation method** | **Residential** | **Commercial and industrial** | **Allocation method** | **Residential** | **Commercial and industrial** |
| **Generation** | | | | | | | |
| Baseload | $100,000,000 | Peak demand (1 CP) | $60,000,000 | $40,000,000 | All energy | $50,000,000 | $50,000,000 |
| Peaking | $50,000,000 | Peak demand (1 CP) | $30,000,000 | $20,000,000 | On-peak energy | $27,500,000 | $22,500,000 |
| Fuel | $100,000,000 | All energy | $50,000,000 | $50,000,000 | All energy | $50,000,000 | $50,000,000 |
| Subtotal | | | $140,000,000 | $110,000,000 | | $127,500,000 | $122,500,000 |
| **Transmission** | $20,000,000 | Peak demand (1 CP) | $12,000,000 | $8,000,000 | 75% all energy/ 25% on-peak energy | $10,300,000 | $9,800,000 |
| **Distribution** | | | | | | | |
| Circuits | $50,000,000 | 50% peak demand/ 50% customer | $37,500,000 | $12,500,000 | 75% all energy/ 25% on-peak energy | $25,600,000 | $24,400,000 |
| Transformers | $20,000,000 | Customer | $18,000,000 | $2,000,000 | 75% all energy/ 25% on-peak energy | $10,300,000 | $9,800,000 |
| Advanced meters | $10,000,000 | Customer | $9,000,000 | $1,000,000 | 50% customer/ 25% all energy/ 25% on-peak energy | $7,100,000 | $2,900,000 |
| Subtotal | | | $64,500,000 | $15,500,000 | | $43,000,000 | $37,000,000 |
| **Billing and collection** | $20,000,000 | Customer | $18,000,000 | $2,000,000 | Customer | $18,000,000 | $2,000,000 |
| **Total** | $370,000,000 | | $234,500,000 | $135,500,000 | | $198,750,000 | $171,250,000 |
| **Average per kWh** | $0.123 | | $0.156 | $0.09 | | $0.133 | $0.114 |
| **Difference** | | | | | | **-15%** | **+26%** |

Note: Numbers may not add up to total because of rounding.

The table depicts two illustrative embedded cost of service study approaches. The reader should note that all of the "demand" labels in the Allocation method column of the *Legacy Study* have been replaced in the *Modern Study* by "Energy." The associated explanatory text in the RAP document states:

> "The point of these illustrative examples is not to suggest a specific approach, nor to defend any of the individual allocation methods shown, but to illustrate how different classification and allocation assumptions affect study results. Simply stating that a proposed cost assignment between classes is "based on the cost of service" may ignore the very important judgments that goes into the assumptions of the study."[41]

[41] Ibid, at 75.

The text also suggests that the *Legacy Study* "presents a method that some industrial and large commercial customer representatives still sometimes propose." The *Modern Study* "is a method that residential consumer advocates often champion." While the difference in methods drives a significant change in the result, both are characterized as "cost of service" results. In my view, it turns cost of service on its head, undermining cost causation principles that have laid the foundation for cost of service analyses for decades and renders the NARUC Manual to forced obsolescence.

**Q. Is it common for utility rates in general to accurately reflect fixed and variable costs of providing service?**

A. No. In fact, it is rare for the rates of a utility like Montana-Dakota to perfectly reflect the fixed and variable costs of providing service. For many utilities, significant portions of total fixed costs are often recovered in variable charges. This is particularly true for the residential and small commercial or general service rate classes. This treatment of a portion of fixed cost as a variable cost creates pricing inefficiencies that can have adverse consequences to utility customers under certain conditions.

**Q. How does the incorporation of fixed costs into variable charges affect customers?**

A. The inclusion of fixed costs in the variable charge sends an inaccurate economic price signal to customers. This price signal <u>overstates</u> the value of energy consumption and <u>understates</u> the costs necessary to be able to provide service regardless of how much energy the customer uses. This inaccuracy essentially overcompensates the customer for energy conservation/efficiency and under compensates the utility for the assets and facilities that are needed to provide customers with any amount of electric service. Conversely, this inaccuracy also overcompensates the utility for its fixed costs when customers use large amounts of energy. The result of this inaccuracy is essentially an intra-class mismatch of costs and revenue. Efficient decisions require that customers understand and pay for the costs of the portions of the system they use and any additional costs they cause the system to incur to support their technology being interconnected to the system.

**Q. Mr. Nelson states "Appropriate or efficient economic price signals are based on marginal cost. In contrast, the Company's calculation of customer costs is based on historic or embedded costs from its COSS. This is completely different than marginal costs and includes several costs - such as the cost of transformers and secondary distribution system - that would not be appropriate in a marginal cost study."[42] Do you agree with his assessment of marginal cost studies?**

A. No. My colleagues and I at Atrium have recently conducted both electric and gas marginal cost studies in three of the relatively small number of remaining jurisdictions that require them (New Hampshire, Montana, and Oregon), and reviewed marginal or long-run incremental cost studies conducted by others. In all instances, the electric studies included the marginal costs related to transformers and secondary distribution systems.

**Q Please describe the purpose for the preparation of a marginal cost of service study?**

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[42] Nelson Direct, at 40:14-18.

A. Marginal cost of service studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional or reduced consumption by customers. The value of marginal cost studies is found in defining optimal seasons and time-of-use ("TOU") rate periods, setting the energy price differential in TOU rates, being sure that on-peak demand charges are high enough to reflect the marginal cost of capacity, and so forth. Marginal cost studies can inform rate design particularly as it relates to fixed customer and demand related costs for a utility that provides default energy services to retail customers who do not elect an alternate energy supplier, or partial requirements customers.

In the context of a rate case, the marginal cost study is less important, driven by the fact that there are no marginal energy costs for delivery service while most of the revenue requirements historically are recovered volumetrically. Since kWhs do not cause delivery costs and marginal cost is based on kWs of demand, there is a fundamental disconnect between marginal cost and rate design. It is only necessary to evaluate fixed and variable costs for the rate effective period, which is often defined as the first twelve to twenty-four months that new rates will be effective.

The length of time needed to define the long run and short run periods for marginal fixed costs varies with different components of the utility system. This may be seen by looking at a marginal cost study where the average cost of a particular service such as billing is used as a proxy for long run costs. In the short run, the marginal cost of billing is the added cost of billing stock and postage because there is no need for additional staff, equipment, or software simply because the increment of one more bill does not change the fixed cost portion of service such as billing software, or for that matter, other components of customer service. It takes a substantial increment of customers to cause billing costs to change more than a value of less than $1.00. The long run may be as much as twenty to fifty years or more for some components of the distribution system unless technology becomes obsolete.

For other parts of the system the long run can be represented by either the physical life or the economic life of an asset, such as a transformer mentioned earlier, and that may vary based on regulatory requirements, technology, class of service, the physical environment, and other factors. Further, every utility will have a different long run (the period over which all costs are variable), because of factors unique to the utility environment and the nature of the sunk costs of the system. Finally, the obligation to serve means that replacing existing facilities is not a marginal cost; that is, there is no growth in the cost drivers from customers and capacity.

**Q. Mr. Nelson states "increasing fixed charges and correspondingly decreasing volumetric charges provides a smaller incentive to conserve energy than would be possible with higher volumetric rates and lower fixed charges… and can undo the progress of customers' efforts to conserve energy by decreasing the control that customers have over their energy bills."[43] Does increasing fixed charges always correspond to decreasing volumetric charges?**

[43] Nelson Direct, at 39:11-16

A. No. Placing more fixed costs in fixed charges results in more conservation simply because it moves the marginal price signal closer to marginal costs for distribution. This provides a better incentive consistent with the Bonbright principle of consumer rationing which is defined as "discouraging wasteful use and encouraging all use that is economically justified." In Bonbright's own words, taken from the portion of his text addressing consumer rationing under a cost-based standard:

> "If the rates were set at less than cost, either overt rationing would be necessary or else service would have to be supplied in wasteful amounts. If the rates were set at more than cost, use of the services thus priced would be unduly restricted."[44]

As part of his discussion of fixed versus variable costs and the fixed-cost standard, Bonbright states the following:

> "In support of this function, rates should be made just high enough to deter potential consumers from demanding services of types and in amounts for which they are unwilling to defray the costs of rendition. But for this purpose of demand control the relevant costs are those costs that can still be avoided by a restriction of output – in short, the escapable or avoidable costs rather than the fixed costs."[45]

This means that customers will make better decisions that may not be reduced energy use but increased use where it is appropriate and efficient to do so. It is important to note that the actual use of energy will be influenced by charges associated with standard offer service, transmission charges and other variable energy costs.

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[44] James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, Second Edition (Public Utility Reports, Inc. 1988), at 111.
[45] Ibid, at 117.

Given a proposed revenue increase, reduced energy use may result from any increase in the total kWh price above the current kWh energy delivery charge. It is also likely that customers will respond not to the marginal kWh price signal but to the total energy utility bill. In that case, the increase in the customer charge will result in reduced energy use as well because the total bill increases.

Montana-Dakota and its customers have the same interest in energy efficiency. Specifically, price signals should reflect the matching principle such that the dollars the customer saves through energy efficiency measures are the same as the costs the Company saves (the matching principle of rate design). By matching rates to the Company's avoided costs, all customers are held harmless from cross subsidy and the Company is provided a reasonable opportunity to earn its allowed return. It is important to recognize that conservation is not just saving more energy. Conservation is the efficient use of energy which may also lead to increased use, such as the case of electric vehicles.

**Q. Mr. Nelson states that it is important to consider the impact on low-income people when designing rates because low-income people have higher "energy burdens," meaning that they spend a disproportionate amount of their income on energy bills. Should this consideration include keeping fixed charges artificially low for all residential customers?**

A. No. A comprehensive study of low income energy affordability by the Oak Ridge National Laboratory in 2020 titled, *Low-Income Energy Affordability: Conclusions from a Literature Review.*[46] examines the persistent problem of high energy burdens among low-income households, based on a review of more than 180

[46] Marilyn A. Brown, Anmol Soni, Melissa V. Lapsa, Katie Southworth, Oak Ridge National laboratory, *Low-Income Energy Affordability: Conclusions from a Literature Review,* March 2020.

publications that pointed to several promising opportunities to address energy affordability and discusses numerous programs to address low income energy burden. Some of the conclusions from the report include:

- Eliminating barriers to serving rental properties could drastically reduce energy burden and insecurity for households while reducing health and other racial disparities. This would benefit from additional research on the nature and role of landlords and property owners.
- The multifamily low-income market has been difficult to reach with traditional energy-efficiency programs due partly to misalignment of incentives.
- The opportunity to address the high energy burden of low-income households occupying manufactured and mobile homes has received limited analysis and policy focus.
- Low-income households in rural communities often spend as much as a quarter of their income on energy due partly to their low-density geography; assistance from local community programs and organizations are particularly critical to success in these markets.

Several promising technology approaches are not generally well integrated into low-income energy programs:

- Rooftop and community solar systems are now cost effective in many states as the result of declining costs and their involvement in low-income energy programs is beginning to take hold in some states.
- Health and safety upgrades are not components of most utility low-income energy-efficiency programs, and they are not fully integrated into the cost-benefit calculations of the state low-income energy programs.
- Information and communication technologies including smart thermostats and information feedback support low-cost behavioral approaches to improving energy efficiency; while they tend not to be incorporated into low-income energy programs, their presence in these programs is increasing.

- Electric vehicles and other approaches to affordable transportation have played limited roles in federal, state, local, and utility low-income energy programs to date.

Policies can be designed to address these gaps:

- States are using minimum requirements and adders to cost-effectiveness tests to promote greater investment in low-income energy programs.
- New program designs can align incentives more effectively for building owners and tenants.
- Strong community engagement and effective building owner and property manager partnerships can help reach multifamily markets.
- Active community involvement can expand participation rates and enhance the success of low-income energy programs.

With respect to utility rate design, the report cited two studies that separately found that: "TOU rate structures … can increase energy cost burdens and have adverse consequences for low-income customers" [Waite et al. (2018)], and "TOU rates can disproportionately increase the bills of households with elderly and disabled occupants, which, for a variety of reasons, may be less able to shift their consumption to low-cost hours of the day" [White and Sintov, (2019)]. Throughout the entire sixty page report no mention was made of fixed customer charges as a source of adverse consequences for low-income utility customers.

## VIII. <u>RATE 30 RATE DESIGN</u>

### A. Montana-Dakota's Position in Direct Testimony

**Q. Please describe the process was used to determine the rate components for each of the rate schedules.**

A. The following process was used to determine the rate components for each of the other rate schedules:

1. The first step was to establish the Basic Service Charge by considering the customer costs identified in the COSS and the Demand Charge based on the demand costs identified in the COSS, for those rate schedules where demand metering is warranted.
2. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and Base Fuel and Purchased Power components for each rate schedule.
3. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the proforma sales under the applicable rate schedule.

The calculations just described were provided for each rate schedule on pages 7 – 26 of Statement L. A summary of the proposed charges for each rate schedule was provided on Statement L pages 4 and 5.

### B. Position of Walmart

**Q Please summarize the recommendation of Walmart witness, Mr. Teague, with regard to the Rate 30 rate design.**

A. Mr. Teague objects to moving Rate 30 rates further from cost of service based levels. Therefore, to avoid doing so, he recommends the present customer, demand, and energy cost allocation percentages be applied to the proposed Rate 30 rate design. If the Commission approves a lower revenue requirement for the Rate 30 class than that proposed by Montana-Dakota, Walmart's rate design should be applied first to the rate design for the Rate 30 class and then apply the revenue requirement reduction to the energy charges.

### C. Montana-Dakota's Response

**Q. What is Montana-Dakota's reaction to Mr. Teague's request?**

A. Montana-Dakota concurs with Mr. Teague's rationale expressed in his testimony for retaining the customer, demand, and energy cost percentage from the current Rate 30 rate design. The Company has considered potential impacts on the remaining customers served by Rate 30 and finds the retention of the current customer, demand, and energy proportions of the rate design is fair and equitable. Having done so, Montana-Dakota will adjust the Rate 30 rate design accordingly at the conclusion of the case.

## IX. CONCLUDING REMARKS

**Q. Please summarize the findings and conclusions in your rebuttal testimony.**

A. My rebuttal findings and conclusions are summarized below: `

Customer Component of the Distribution System

Mr. Nelson's critique of the minimum system and zero-intercept analyses amounts to an opinion based on an apparent misunderstanding of cost causation as it relates to the design and construction of Montana Dakota's electric distribution system but is consistent with his preferred approach; that is, the Basic Customer method. He asserts the minimum system method "requires the analyst to create a hypothetical, no-capacity system something that is not real and not directly based on system characteristics." Any utility cost analyst or authoritative utility industry literary source would agree that the zero-intercept analysis is not intended to be a reflection of engineering design criteria – no electric utility engineer would design, nor a utility construct, a set of distribution facilities of zero capacity. The zero-intercept analysis is a statistical method based on the assumption that there is a degree of demand serving capacity in even the smallest available unit size of a distribution plant component. The minimum system and zero-intercept methods identify the portion of the aggregate electric distribution system components that represents the cost to extend access to electricity service to customers and is therefore customer-related. Mr. Nelson's Basic Customer method for classification and allocation of Montana-Dakota's electric distribution system should be rejected.

Montana-Dakota's Line Loss Study

Montana-Dakota has provided an updated summary of its 2022 Line Loss Study as an exhibit to this rebuttal testimony in response to Public Advocacy Staff's identification of an apparent insufficiency in a Statement K workpaper justifying the updated line losses.

Allocation of Production Plant

Montana-Dakota continues to support the 12-CP method for production and transmission demand-related costs on its system over the preferred 4-CP method offered by Marathon Petroleum Company. The Company's analysis satisfies the FERC's "three peak ratios test" and better represents the total demand on system capacity, not simply the system load demand. This is an important distinction because load is not the only demand placed on capacity. Generation capacity must also be maintained and based on certain conditions that prevent it from being fully available to serve load. Based on the full demand on capacity, the 12-CP allocation factor reflects cost causation for the system based on all of the operating characteristics of the system.

Allocation of Fuel and Purchase Power

Marathon witness, Ms. Maini, states that Montana-Dakota's flat kWh allocator for fuel and purchased power energy costs fails to recognize hourly energy cost, load variations, and support an E8760 allocation method. Fuel costs vary by the hour and are typically higher in the week daytime hours compared to nighttime and weekend hours. Montana-Dakota has indicated its willingness to investigate the development of the E8760 allocation method, prepare an evaluation of its application, and proposal for its next electric North Dakota general rate case, for allocation of the Company's fuel and purchased power energy costs.

<u>Class Revenue Apportionment</u>

Montana-Dakota continues to support the class revenue apportionment method described in my direct testimony and for the reasons stated therein and summarized in this rebuttal testimony. Given that the underlying basis for AARP witness, Mr. Nelson's proposed class revenue apportionment is COSS results under his basic customer method of cost allocation, I recommend that the Commission reject it. The remaining parties are not recommending changes to the Company's class revenue apportionment approach.

<u>Residential Rate Design</u>

AARP witness, Mr. Nelson disagrees with Montana-Dakota's proposed residential rate design because the justification for the increased charge is directly related to the results of the Company's minimum system study; high customer charges harm customers, including low-usage and low- income customers as well as those investing in energy efficiency; and the Company's justification for its proposed customer charge increase lacks theoretical and analytical support. Each of his arguments, which are grounded in his Basic Customer method for cost classification and allocation, have been addressed and refuted in this rebuttal testimony. I recommend that his recommendation to keep the residential basic service charge at its current level be rejected.

Rate 30 Rate Design

Montana-Dakota concurs with Walmart witness, Mr. Teague's rationale expressed in his testimony for retaining the customer, demand, and energy cost percentage from the current Rate 30 rate design and commits to adjusting the Rate 30 rate design accordingly at the conclusion of the case.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

# Loss Data for Substations, Distribution Transformers and Distribution Lines

## Substation Losses

| Transformer Size(kVA) | Peak Load (90%) (kW) | No Load Losses (kW) | Load Losses (kW) | Load Factor | Loss Factor | Average Load Loss (kW) | Average Loss | Peak Loss |
|---|---|---|---|---|---|---|---|---|
| 2500 | 2025 | 2 | 7.5 | 61.10% | 44.46% | 4.22 | 0.34% | 0.47% |
| 5000 | 4050 | 4 | 15 | 61.10% | 44.46% | 8.45 | 0.34% | 0.47% |
| 7500 | 6075 | 6 | 22.5 | 61.10% | 44.46% | 12.67 | 0.34% | 0.47% |
| 10000 | 8100 | 8 | 28.416 | 61.10% | 44.46% | 16.19 | 0.33% | 0.45% |
| 15000 | 12150 | 12 | 47.73 | 61.10% | 44.46% | 26.56 | 0.36% | 0.49% |
| | | | | | | **Average** | **0.342%** | **0.470%** |

**Substation Data Notes:**

61.10% Is the 2022 Load Factor of North Dakota obtained from the Systems Operations Department
90% Assumed Peak Load
90% Assumed Power Factor
8760 hours in one year
LSF = .3*LF + .7*LF^2 "Transmission and Distribution Electrical Engineering" by Colin Bayliss

## Distribution Line Losses

| | Substation Load (kW) | Losses (kW) | Load Factor | Loss Factor | Average Load Loss (kW) | Average Loss | Peak Loss |
|---|---|---|---|---|---|---|---|
| **Urban** | 11788.37 | 241.37 | 53.47% | 36.05% | 87.02 | **0.74%** | **2.05%** |
| **Rural** | 2461.89 | 366.04 | 53.47% | 36.05% | 131.96 | **5.36%** | **14.87%** |
| | | | | | **Weighed Average** | **0.902%** | **2.502%** |

**Distribtion Line Data Notes:**

96.46% of ND Customers are inside city limits.
3.54% of ND customers are rural
53.47% Is the average of the Substation Load Factor and the Residential Load Factor.
Service point data queried from the GIS
100610 Service points within the state (captured in the GIS regardless if there is a rate associated with the service or not)
97045 Service points within city limits in North Dakota
3565 Service points outside city limits in North Dakota
LSF = .3*LF + .7*LF^2 = Ave Load Loss / Peak Load Loss
Old Loss Factor used = (LF+LF^2)*.5
LSF = .3*LF + .7*LF^2 "The Electrical Engineering Handbook, 3rd Edition, Systems, Controls, Embedded Systems, Energy, and Machines" by Richard C. Dorf
"Generation, Distribution and Utilization of Electrical Energy" by C.L. Wadhwa
"Transmission and Distribution Electrical Engineering" by Colin Bayliss

## Distribution Transformer Losses

| | Transformer Size(kVA) | Peak Load (kW) | No Load Losses (kW) | Load Losses (kW) | Load Factor | Loss Factor | Average Load Loss (kW) | Average Loss | Peak Loss | Average No Load Loss (Watt/kVA) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Residential, peak 80% of rating** | 25 | 20 | 0.065 | 0.275 | 45.83% | 24.73% | 0.08 | 0.92% | 1.70% | 2.6 |
| **Residential, peak 80% of rating** | 50 | 40 | 0.115 | 0.48 | 45.83% | 24.73% | 0.15 | 0.80% | 1.49% | 2.3 |
| **Small Commercial, peak 90% of rating** | 45 | 41 | 0.16 | 0.37 | 36.98% | 17.17% | 0.09 | 0.61% | 1.31% | 3.6 |
| **Large Commercial, peak 90% of rating** | 150 | 135 | 0.45 | 0.835 | 36.52% | 16.82% | 0.22 | 0.44% | 0.95% | 3.0 |
| **Large Commercial, peak 90% of rating** | 225 | 203 | 0.62 | 1.325 | 36.52% | 16.82% | 0.33 | 0.44% | 0.96% | 2.8 |
| **Large Commercial, peak 90% of rating** | 300 | 270 | 0.75 | 1.4 | 36.52% | 16.82% | 0.36 | 0.37% | 0.80% | 2.5 |
| | | | | | | | **Weighted Average** | **0.762%** | **1.437%** | **3.0** |

**Distribtion Transformer Data Notes:**

8760 hours in one year
45 KVA transformer would fall under the Small General Rate and Load Factor
150 KVA sizes and higher transformers are under the Large General Rate and Load Factor
79.38% RATE 100 (Residential)
9.64% RATE 200 (Small Commercial - Secondary)
5.04% RATE 300(Large Commercial - Secondary)
80% Loading for Residential
90% Loading for Commercial
90% Assumed Power Factor

LF = Ave Load Demand / Peak Load Demand
LSF = Ave (load demand)^2 / Max (load demand)^2
"Transmission and Distribution Electrical Engineering" by Colin R. Bayliss

Old Load Yearly Loss = (PeakLoad*LF/xfmrkVA)^2 * load loss * 8784
LSF = .15*LF + .85*LF^2 Distribution Transformer Loss Factor calculation is from book "Energy Efficient Transformers" by Barry W. Kennedy
"Transmission and Distribution Electrical Engineering" by Colin Bayliss

## Loss Data for Substations, Distribution Transformers and Distribution Lines

### Service Line Losses

| RATE AND DESCRIPTION | Customer Fraction of Rate | Length of Service | Volts | Ohms per 1000ft | Peak (Watts) | Current | Peak Loss (Watts) | Peak % loss | Load Factor | Avg Loss (Watts) | Average Loss | Weighted Average Loss | Weighted Peak Loss |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RATE MDUND100 (Residential) | | | | | | | | | | | | | |
| #2 OH Triplex | 32.87% | 125 | 240 | 0.293 | 5000 | 23.1481 | 39.2500 | 0.79% | 46% | 8.24554652 | 0.36% | 0.1183% | 0.2581% |
| 1/0 OH Triplex | 1.40% | 125 | 240 | 0.184 | 5000 | 23.1481 | 24.6485 | 0.49% | 46% | 5.17809065 | 0.23% | 0.0032% | 0.0069% |
| 4/0 OH Triplex | 0.59% | 125 | 240 | 0.092 | 5000 | 23.1481 | 12.3242 | 0.25% | 46% | 2.58904532 | 0.11% | 0.0007% | 0.0015% |
| 1/0 UG Triplex | 32.91% | 0 | 240 | 0.2001 | 5000 | 23.1481 | 0.0000 | 0.00% | 46% | 0 | 0.00% | 0.0000% | 0.0000% |
| 4/0 UG Triplex | 13.86% | 160 | 240 | 0.0999 | 5000 | 23.1481 | 17.1296 | 0.34% | 46% | 3.59854787 | 0.16% | 0.0218% | 0.0475% |
| 350 UG Triplex | 3.66% | 160 | 240 | 0.0606 | 5000 | 23.1481 | 10.3909 | 0.21% | 46% | 2.18290291 | 0.10% | 0.0035% | 0.0076% |
| 350-2 UG Triplex | 0.03% | 160 | 240 | 0.0606 | 5000 | 23.1481 | 10.3909 | 0.21% | 46% | 2.18290291 | 0.10% | 0.0000% | 0.0001% |
| 350-3 UG Triplex | 0.39% | 160 | 240 | 0.0606 | 5000 | 23.1481 | 10.3909 | 0.21% | 46% | 2.18290291 | 0.10% | 0.0004% | 0.0008% |
| 2 OH Quad | 0.04% | 125 | 208 | 0.184 | 5000 | 15.4211 | 16.4090 | 0.33% | 46% | 3.44715607 | 0.15% | 0.0001% | 0.0001% |
| 1/0 OH Quad | 0.02% | 125 | 208 | 0.092 | 5000 | 15.4211 | 8.2045 | 0.16% | 46% | 1.72357803 | 0.08% | 0.0000% | 0.0000% |
| 4/0 OH Quad | 0.20% | 0 | 208 | 0.2001 | 5000 | 15.4211 | 0.0000 | 0.00% | 46% | 0 | 0.00% | 0.0000% | 0.0000% |
| 1/0 UG Quad | 0.56% | 160 | 208 | 0.0999 | 5000 | 15.4211 | 11.4035 | 0.23% | 46% | 2.39562359 | 0.10% | 0.0006% | 0.0013% |
| 4/0 UG Quad | 1.65% | 35 | 208 | 0.0606 | 5000 | 15.4211 | 3.0264 | 0.06% | 46% | 0.63577548 | 0.03% | 0.0005% | 0.0010% |
| 350 UG Quad | 0.76% | 35 | 208 | 0.0606 | 5000 | 15.4211 | 3.0264 | 0.06% | 46% | 0.63577548 | 0.03% | 0.0002% | 0.0005% |
| 350-2 UG QUAD | 1.52% | 35 | 208 | 0.0606 | 5000 | 15.4211 | 3.0264 | 0.06% | 46% | 0.63577548 | 0.03% | 0.0004% | 0.0009% |
| 350-3 UG QUAD | 1.08% | 35 | 208 | 0.0606 | 5000 | 15.4211 | 0.7566 | 0.02% | 46% | 0.15894387 | 0.01% | 0.0001% | 0.0002% |
| 500 UG Quad | 1.17% | 35 | 208 | 0.0074 | 5000 | 15.4211 | 0.3696 | 0.01% | 46% | 0.07763595 | 0.00% | 0.0000% | 0.0001% |
| 500-2 UG Quad | 1.01% | 35 | 208 | 0.0074 | 5000 | 15.4211 | 0.3696 | 0.01% | 46% | 0.07763595 | 0.00% | 0.0000% | 0.0001% |
| 500-3 UG QUAD | 0.67% | 35 | 208 | 0.0074 | 5000 | 15.4211 | 0.0924 | 0.00% | 46% | 0.01940899 | 0.00% | 0.0000% | 0.0000% |
| | 94.39% | | | | | | | | | | **Totals** | 0.1497% | 0.3265% |
| RATE MDUND200 (Small Commercial - Secondary) | | | | | | | | | | | | | |
| #2 OH Triplex | 25.62% | 125 | 240 | 0.293 | 5000 | 23.1481 | 39.2500 | 0.79% | 37% | 5.36694286 | 0.29% | 0.0744% | 0.2011% |
| 1/0 OH Triplex | 3.83% | 125 | 240 | 0.184 | 10000 | 46.2963 | 98.5940 | 0.99% | 37% | 13.4814674 | 0.36% | 0.0140% | 0.0378% |
| 4/0 OH Triplex | 1.51% | 125 | 240 | 0.092 | 15000 | 69.4444 | 110.9182 | 0.74% | 37% | 15.1666508 | 0.27% | 0.0041% | 0.0112% |
| 1/0 UG Triplex | 25.30% | 0 | 240 | 0.2001 | 10000 | 46.2963 | 0.0000 | 0.00% | 37% | 0 | 0.00% | 0.0000% | 0.0000% |
| 4/0 UG Triplex | 17.74% | 160 | 240 | 0.0999 | 20000 | 92.5926 | 274.0741 | 1.37% | 37% | 37.4761347 | 0.51% | 0.0899% | 0.2431% |
| 350 UG Triplex | 4.56% | 160 | 240 | 0.0606 | 50000 | 231.4815 | 1,039.0947 | 2.08% | 37% | 142.082943 | 0.77% | 0.0351% | 0.0948% |
| 350-2 UG Triplex | 0.07% | 160 | 240 | 0.0606 | 50000 | 231.4815 | 1,039.0947 | 2.08% | 37% | 142.082943 | 0.77% | 0.0005% | 0.0014% |
| 350-3 UG Triplex | 0.08% | 160 | 240 | 0.0606 | 50000 | 231.4815 | 1,039.0947 | 2.08% | 37% | 142.082943 | 0.77% | 0.0006% | 0.0016% |
| #2 OH Quad | 3.59% | 125 | 208 | 0.293 | 5000 | 15.4211 | 26.1295 | 0.52% | 37% | 3.57287867 | 0.19% | 0.0069% | 0.0188% |
| 1/0 OH Quad | 2.18% | 125 | 208 | 0.184 | 10000 | 30.8423 | 65.6359 | 0.66% | 37% | 8.97487612 | 0.24% | 0.0053% | 0.0143% |
| 4/0 OH Quad | 2.53% | 125 | 208 | 0.092 | 25000 | 77.1057 | 205.1123 | 0.82% | 37% | 28.0464879 | 0.30% | 0.0077% | 0.0208% |
| 1/0 UG Quad | 2.08% | 0 | 208 | 0.2001 | 20000 | 61.6845 | 0.0000 | 0.00% | 37% | 0 | 0.00% | 0.0000% | 0.0000% |
| 4/0 UG Quad | 3.91% | 160 | 208 | 0.0999 | 35000 | 107.9479 | 558.7729 | 1.60% | 37% | 76.4050715 | 0.59% | 0.0231% | 0.0624% |
| 350-2 UG QUAD | 0.42% | 35 | 208 | 0.0606 | 60000 | 185.0536 | 217.8999 | 0.36% | 37% | 29.7950279 | 0.13% | 0.0006% | 0.0015% |
| 350-3 UG QUAD | 0.42% | 35 | 480 | 0.0074 | 60000 | 80.1899 | 2.4982 | 0.00% | 37% | 0.34159939 | 0.00% | 0.0000% | 0.0000% |
| 500 UG Quad | 0.12% | 35 | 208 | 0.0606 | 60000 | 185.0536 | 108.9499 | 0.18% | 37% | 14.8975139 | 0.07% | 0.0001% | 0.0002% |
| 500-2 UG Quad | 0.18% | 35 | 208 | 0.0606 | 60000 | 185.0536 | 101.1136 | 0.17% | 37% | 13.825999 | 0.06% | 0.0001% | 0.0003% |
| 500-3 UG Quad | 0.09% | 35 | 208 | 0.0606 | 60000 | 185.0536 | 101.1136 | 0.17% | 37% | 13.825999 | 0.06% | 0.0001% | 0.0001% |
| 500-4 UG Quad | 0.09% | 35 | 480 | 0.0074 | 60000 | 80.1899 | 2.4982 | 0.00% | 37% | 0.34159939 | 0.00% | 0.0000% | 0.0000% |
| 500-6 UG Quad | #N/A | 35 | 480 | 0.0074 | 60000 | 80.1899 | 2.4982 | 0.00% | 37% | 0.34159939 | 0.00% | #N/A | #N/A |
| | #N/A | | | | | | | | | | **Totals** | 0.2623% | 0.7094% |

## Loss Data for Substations, Distribution Transformers and Distribution Lines

RATE MDUND300(Large Commercial - Secondary)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| #2 OH Triplex | 6.14% | 125 | 240 | 0.293 | 15000 | 69.4444 | 353.2504 | 2.36% | 37% | 47.1229183 | 0.86% | 0.0529% | 0.1447% |
| 1/0 OH Triplex | 1.98% | 125 | 240 | 0.092 | 50000 | 231.4815 | 1,232.4246 | 2.46% | 37% | 164.403052 | 0.90% | 0.0179% | 0.0489% |
| 4/0 OH Triplex | 1.22% | 125 | 240 | 0.092 | 50000 | 231.4815 | 1,232.4246 | 2.46% | 37% | 164.403052 | 0.90% | 0.0110% | 0.0302% |
| 1/0 UG Triplex | 11.99% | 0 | 240 | 0.2001 | 25000 | 115.7407 | 0.0000 | 0.00% | 37% | 0 | 0.00% | 0.0000% | 0.0000% |
| 4/0 UG Triplex | 9.61% | 160 | 240 | 0.0999 | 40000 | 185.1852 | 1,096.2963 | 2.74% | 37% | 146.243806 | 1.00% | 0.0962% | 0.2633% |
| 350 UG Triplex | 5.17% | 160 | 240 | 0.0606 | 100000 | 462.9630 | 4,156.3786 | 4.16% | 37% | 554.452868 | 1.52% | 0.0785% | 0.2150% |
| 350-2 UG Triplex | 0.19% | 160 | 240 | 0.0606 | 100000 | 462.9630 | 4,156.3786 | 4.16% | 37% | 554.452868 | 1.52% | 0.0029% | 0.0079% |
| 350-3 UG Triplex | 0.15% | 160 | 240 | 0.0606 | 100000 | 462.9630 | 4,156.3786 | 4.16% | 37% | 554.452868 | 1.52% | 0.0022% | 0.0061% |
| 2 OH QUAD | 3.55% | 125 | 208 | 0.293 | 5000 | 15.4211 | 26.1295 | 0.52% | 37% | 3.48562744 | 0.19% | 0.0068% | 0.0185% |
| 1/0 OH Quad | 3.13% | 125 | 208 | 0.184 | 25000 | 77.1057 | 410.2245 | 1.64% | 37% | 54.7231612 | 0.60% | 0.0187% | 0.0513% |
| 4/0 OH Quad | 12.20% | 125 | 208 | 0.092 | 80000 | 246.7381 | 2,100.3497 | 2.63% | 37% | 280.182586 | 0.96% | 0.1170% | 0.3204% |
| 1/0 UG Quad | 6.71% | 0 | 208 | 0.2001 | 40000 | 123.3691 | 0.0000 | 0.00% | 37% | 0 | 0.00% | 0.0000% | 0.0000% |
| 4/0 UG Quad | 12.20% | 160 | 208 | 0.0999 | 70000 | 215.8959 | 2,235.0917 | 3.19% | 37% | 298.156908 | 1.17% | 0.1423% | 0.3897% |
| 350 UG Quad | 7.85% | 35 | 208 | 0.0606 | 100000 | 308.4227 | 605.2774 | 0.61% | 37% | 80.7428348 | 0.22% | 0.0174% | 0.0475% |
| 500 UG Quad | 1.88% | 35 | 208 | 0.0606 | 100000 | 308.4227 | 302.6387 | 0.30% | 37% | 40.3714174 | 0.11% | 0.0021% | 0.0057% |
| 500-2 UG Quad | 2.24% | 35 | 208 | 0.0074 | 100000 | 308.4227 | 34.2978 | 0.03% | 37% | 4.57526037 | 0.01% | 0.0003% | 0.0008% |
| 500-3 UG Quad | 1.56% | 35 | 480 | 0.0074 | 300000 | 400.9494 | 124.9109 | 0.04% | 37% | 16.6628695 | 0.02% | 0.0002% | 0.0007% |
| 500-6 UG Quad | 0.34% | 35 | 480 | 0.0074 | 300000 | 400.9494 | 62.4554 | 0.02% | 37% | 8.33143475 | 0.01% | 0.0000% | 0.0001% |
| 500-8 UG Quad | 0.19% | 35 | 480 | 0.0074 | 300000 | 400.9494 | 62.4554 | 0.02% | 37% | 8.33143475 | 0.01% | 0.0000% | 0.0000% |
| 500-4 UG Quad | 1.06% | 35 | 480 | 0.0074 | 300000 | 400.9494 | 62.4554 | 0.02% | 37% | 8.33143475 | 0.01% | 0.0001% | 0.0002% |
| | 89.38% | | | | | | | | | | **Totals** | 0.5665% | 1.5511% |
| | | | | | | | | | | | **Weighted Average Service Loses=** | **0.173%** | **0.406%** |

**Service Line Data Notes:**

90% Assumed Power Factor

**Average Percentage of Rates of Service**

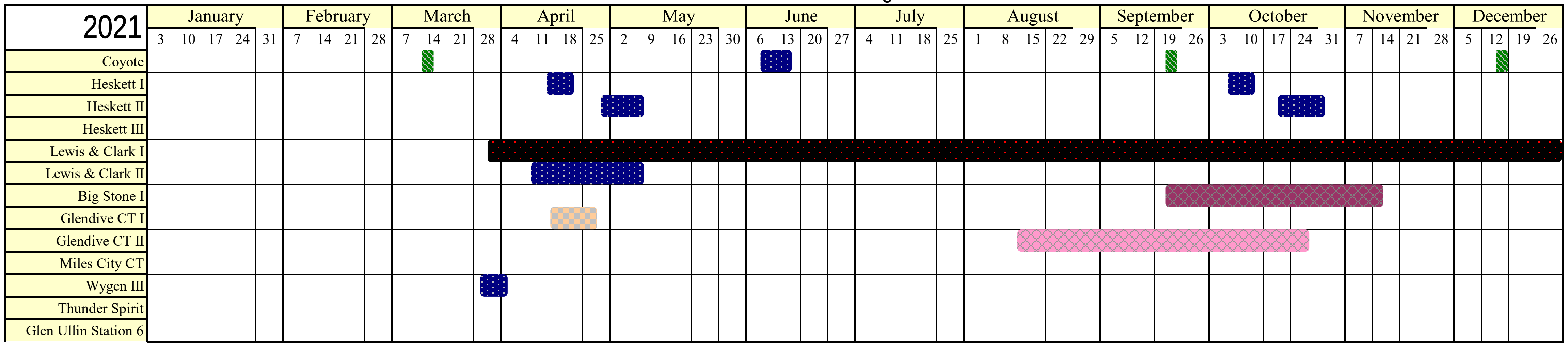
79.38% RATE MDUND100 (Residential)
9.64% RATE MDUND200 (Small Commercial - Secondary)
5.04% RATE MDUND300(Large Commercial - Secondary)

**Survey of Cost Classification of Electric Distribution**

| State | Electric Utility | Customer Component of Distribution | | Docket/Case Number | Year |
|---|---|---|---|---|---|
| | | Recognized | Method | | |
| **AZ** | Tucson Electric Power Co. | Yes | Minimum System | D-E-01933A-15-0322 | 2015 |
| **CT** | The CT Light & Power Co | Yes | Minimum System | D-17-10-46 | 2017 |
| **FL** | Tampa Electric Company | Yes | Min.Distribution System | 20210034-EI | 2022 |
| **GA** | Georgia Power Co. | Yes | Minimum System | D-42516 | 2019 |
| **HI** | Hawaii Electric Light Co | Yes | Minimum System | D-2018-0368 | 2018 |
| **ID** | Idaho Power Company | Yes | Unspecified | IPC-E-l1-08 | 2011 |
| **KS** | Evergy Kansas Central Inc. | Yes | Minimum System | D-18-WSEE-328-RTS | 2018 |
| **ME** | Central Maine Power Co. | Yes | Minimum System | D-2018-00194 | 2018 |
| **MN** | Minnesota Power Entrprs Inc. | Yes | Minimum System | D-E-015/GR-16-664 | 2016 |
| **MS** | Mississippi Power Co. | Yes | Zero Intercept | 2019-UN-0219 | 2019 |
| **MO** | Evergy Missouri Metro | Yes | Minimum System | C-ER-2022-0129 | 2022 |
| **MT** | MDU Resources Group, Inc. | Yes | Minimum System | 2022.11.099 | 2022 |
| **NH** | Unitil Energy Systems Inc. | Yes | Minimum System | D-DE-16-384 | 2016 |
| **NY** | Consolidated Edison Co. of NY | Yes | Minimum System | C-16-E-0060 | 2016 |
| **NC** | Duke Energy Carolinas, LLC | Yes | Minimum System | E-7, Sub 1214 | 2019 |
| **ND** | Northern States Power Co. | Yes | Both | C-PU-20-441 | 2020 |
| **OH** | Duke Energy Ohio | Yes | Minimum System | 21-887-EL-AIR | 2022 |
| **OK** | Oklahoma Gas and Electric Co. | Yes | Zero Intercept | Ca-PUD201500273 | 2015 |
| **PA** | PPL Electric Utilities Corp. | Yes | Minimum System | D-R-2015-2469275 | 2015 |
| **SC** | Duke Energy Progress LLC | Yes | Minimum System | D-2018-318-E | 2018 |
| **SD** | Xcel Energy | Yes | Minimum System | EL14-058 | 2014 |
| **VA** | Virginia Electric and Power Co. | Yes | Unspecified | C-PUE-2009-00019 | 2009 |
| **WI** | Wisconsin Electric Power Co. | Yes | Minimum System | D-05-UR-107 | 2014 |

# Montana-Dakota Utilities Co.

## Scheduled Power Plant Outages [1] [2]




*Last Revision: 03/25/2021*

[1] Start date: Day after unit comes offline.
[2] End date: Day of unit coming online.

[3] Dates flexible to accomodate dispatch; outages typically a few hours per day, spread over a number of days/weeks.

| | | SPRING | | FALL |
|---|---|---|---|---|
| Coyote | ------- | Mar 09 - Mar 11 & Jun 04 - Jun 11 | ------- | Sep 16 - Sep 18 & Dec 10 - Dec 12 |
| Heskett I | ------- | Apr 10 - Apr 16 | ------- | Oct 02 - Oct 08 |
| Heskett II | ------- | Apr 24 - May 04 | ------- | Oct 15 - Oct 26 |
| Heskett III | ------- | | ------- | |
| Lewis & Clark I | ------- | Mar 31 - Dec 31 | ------- | |
| Lewis & Clark II | ------- | Apr 06 - May 04 | ------- | |
| Big Stone I | ------- | | ------- | Sep 16 - Nov 10 |
| Glendive CT I | ------- | Apr 11 - Apr 22 | ------- | |
| Glendive CT II | ------- | | ------- | Aug 09 - Oct 22 |
| Miles City CT | ------- | | ------- | |
| Wygen III | ------- | Mar 24 - Mar 30 | ------- | |
| Thunder Spirit | ------- | | ------- | |
| Glen Ullin Station 6 | ------- | | ------- | |

- Cleaning (Boiler/Scrubber/Other)
- Maintenance (General Plant)
- Maintenance (Major Turbine/Generator)
- Maintenance (Major Boiler)
- Maintenance (Major Environmental)
- Gas Turbine General Plant Maintenance [3]
- Gas Turbine Combustion Inspection
- Gas Turbine Hot Gas Path Inspection
- Gas Turbine Major Inspection/Overhaul
- Plant Decommissioning