MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony

Of

Nicole A. Kivisto

INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole A. Kivisto, and my business address is 1200 West Century Avenue, Bismarck, North Dakota 58503.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) of MDU Resources Group, Inc. (MDU Resources). I also continue to serve as President and CEO of Montana-Dakota Utilities Co. (Montana-Dakota or Company), Cascade Natural Gas Corporation (Cascade), and Intermountain Gas Company (Intermountain) which are all subsidiaries of MDU Resources. These subsidiaries, combined with Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, are collectively referred to as the MDU Utilities Group.

Q. Please describe your duties and responsibilities with MDU Utilities Group.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above-mentioned companies that, in combination, serve over 1.2 million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting from Minnesota State University Moorhead. I began working for MDU Resources/Montana-Dakota in 1995 and have been in my current capacity since January 2024. I was the President and CEO of Montana-Dakota, Cascade, Intermountain, and Great Plains from January 2015 until assuming my present position in January 2024.

Prior to that I was the Vice President-Operations of Montana-Dakota and Great Plains for one year. Before that I was the Vice President, Controller, and Chief Accounting Officer for MDU Resources for nearly four years and held other finance related positions prior to that.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming, the Public Utilities Commissions of Idaho, Minnesota, and South Dakota, the Public Utility Commission of Oregon, and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a comprehensive executive overview of Montana-Dakota's electric operations in North

Dakota and of the Company's request for an adjustment in electric rates. Specifically, I will:

- Provide a high-level overview of Montana-Dakota's organizational structure, service territory, and integrated electric system;
- Introduce the Company's witnesses and summarize the scope of testimony supporting this filing;
- Address the Company's commitment to affordability, including external factors affecting costs and the Company's efforts to maintain reasonable rates while supporting safe and reliable service;
- Describe Montana-Dakota's approach to serving data centers in its service territory, with a focus on cost causation, risk mitigation, ensuring no adverse impact on existing customers, and resulting customer benefits;
- Provide an overview of the Company's requested rate increase and the fundamental drivers underlying the request as well as Montana-Dakota's ongoing investment strategy to maintain and enhance its electric infrastructure to meet evolving customer needs and system requirements.

COMPANY OVERVIEW

Q. Please describe Montana-Dakota's organizational structure and recent changes.

A. Montana-Dakota Utilities Co. is a wholly owned subsidiary of MDU Resources Group, Inc., a holding company that owns a portfolio of regulated energy delivery businesses. Montana-Dakota operates as a vertically integrated electric and natural gas distribution utility, and its operations, financing, and regulatory obligations are distinct from other entities within the holding company structure.

MDU Resources started as a small electric utility in 1924 and recently reached a significant milestone by celebrating 100 years in business on March 14, 2024. Over the past 100 years, MDU Resources has continued to evolve by expanding into different business lines and growing its utility. In 2023, MDU Resources spun off Knife River, its former construction materials and contracting business, and in 2024 spun off Everus Construction Group, its former construction services business, into separate publicly traded companies.

The completion of these strategic initiatives brings MDU Resources to its desired state of focusing on its core business as a pure play regulated energy delivery company, allowing management and the board of directors to focus on the utility and pipeline businesses. With this new day, the Company has implemented a "CORE" strategy, which prioritizes customers and communities, operational excellence, returns focused initiatives and an employee driven culture.

Q. How have these changes impacted the Company from a financial and governance perspective?

A. These changes have increased the transparency of the utility business and support a clearer evaluation of Montana-Dakota's costs, risks, and performance on a standalone basis. The separation also enables a more focused capital strategy tailored specifically to the needs of regulated utility operations, which ultimately benefits customers through improved access to capital.

Q. The “CORE” strategy prioritizes customers. Please describe how Montana-Dakota demonstrates that prioritization to its North Dakota electric customers.

A. Montana-Dakota supports its customers through a combination of operations and centralized customer service functions. Customers have toll-free access to the Customer Experience Team and the Credit Center to place routine utility service requests and inquiries from 7:30 am to 6:30 pm local time, Monday through Friday, and emergency calls on a 24-hour basis. Customers also have the option to chat with an agent online from 10:00 am to 5:00 pm local time, Monday through Friday. A scheduling center, part of the Customer Experience Team, transmits electronic service orders to the mobile terminals placed in the fleet of service and construction vehicles. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Another tenet of the “CORE” strategy is operations. Please provide a summary of Montana-Dakota's electric operations in North Dakota.

A. North Dakota is a part of Montana-Dakota’s interconnected electric system, which consists of generation, transmission, distribution, and general plant facilities serving approximately 94,700 customers in 118 communities in North Dakota. The Company's North Dakota electric service area is divided into two operating regions with regional offices located in Bismarck and Dickinson. In addition, there are several district offices located in communities throughout the state. As of December 31, 2025, the Company had 500 full and part-time employees who live and work throughout the Company's North Dakota electric and gas service area.

Q. Please describe Montana-Dakota's interconnected electric system.

A. Through its interconnected electric system, Montana-Dakota serves approximately 129,000 retail customers in portions of North Dakota, Montana, and South Dakota. Montana-Dakota's current portfolio of generation assets is comprised of baseload coal-fired generation, natural gas-fired peaking generation, wind generation, and portable diesel units. Capacity and energy are also provided through Power Purchase Agreements. Montana-Dakota plans to maintain and operate its current fleet of generation resources, consistent with the Company's integrated resource planning process, which identifies a balanced, cost-effective mix of generation and purchased power to serve its customers.

The Company's projected 2027 capacity mix includes 827.5 MW of owned generation and another 160.3 MW of purchased capacity, for a total capacity of 987.8 MW. Table 1 provides a detailed breakout of the resources included in that mix, Figure 1 summarizes the projected 2027 capacity mix by resource type, and Figure 2 shows the projected 2027 energy resources expected to serve customers.

Table 1: Projected 2027 Capacity Mix by Resource

Facility	Capacity (MW)
Coal	
Big Stone	94.1
Coyote	103.6
Total	197.7
Gas	
Miles City	23.2
Glendive Unit I and II	75.5
Heskett Unit III	88.2
Heskett Unit IV	88.4
Lewis and Clark Unit II - RICE	18.7
Portables	3.7
Total	297.7
Renewable	
Diamond Willow	30.0
Cedar Hills	19.5
Thunder Spirit	155.5
Badger Wind	127.1
Total	332.1
Purchased Power	
Badger Wind	27.5
Badger Wind (Capacity only)	100.0
Total	127.5
DSM 1/	
Interuptible	10.4
Commercial	22.4
Total	32.8
Grand Total	987.8

1/ Based on summer accreditation in MISO.

Figure 1: Projected 2027 Capacity Mix

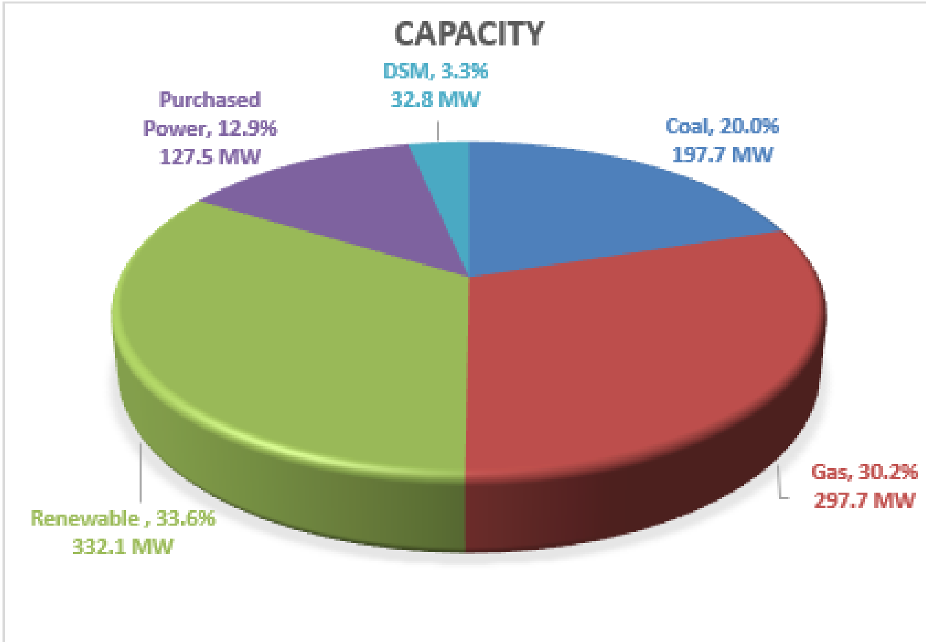
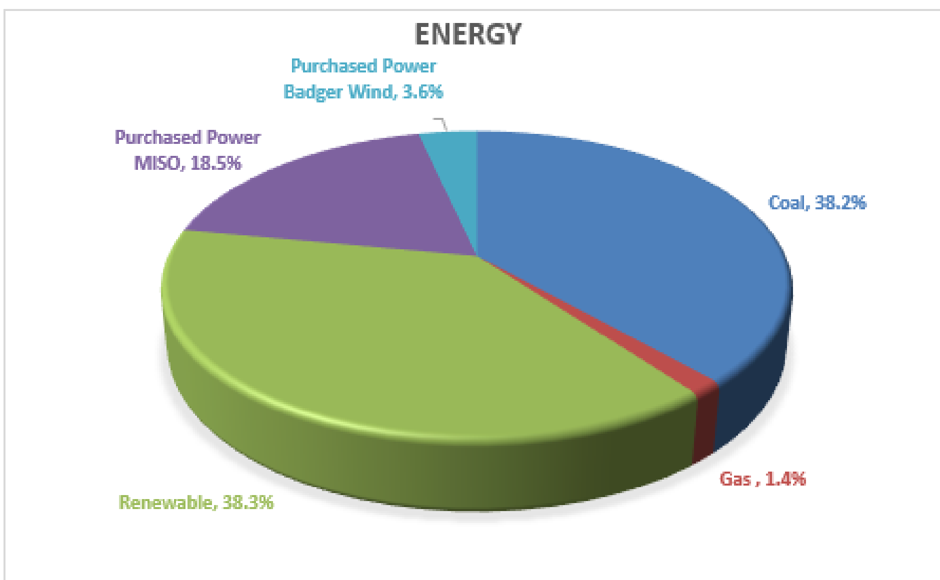


Figure 2: Projected 2027 Energy Resources



Q. What changes has the Company made to its generation facilities since the prior rate case?

A. Montana-Dakota has made three significant changes. The Company acquired a 49% ownership interest in the Badger Wind Project in late 2025 and completed repower projects at the Cedar Hills and Diamond Willow (Phase 2) wind facilities. These projects are included in the Renewable Resource Cost Adjustment (Renewable Rider) and are not part of this Case. Montana-Dakota also retired the Glen Ullin Station 6 waste heat electric generating unit June 1, 2026, which is reflected in this proceeding.

Q. Please describe Montana-Dakota's riders, including their purpose, and how they are treated in this case.

A. Montana-Dakota currently has four riders that the Company may utilize to recover certain costs outside of base rates: the previously mentioned Renewable Rider, the Generation Resource Recovery Rider (Generation Rider), the Transmission Cost Adjustment (Transmission Rider), and the Environmental Cost Recovery Rider (Environmental Rider), although there is no current recovery under the Environmental Rider.

In this proceeding, Montana-Dakota proposes to transfer plant in service previously authorized for recovery in the Transmission Rider to base rates. Transmission-related expenses and revenues, specifically those related to the operations and services provided by the regional

RTOs or similar organizations, will remain in the Transmission Rider for future recovery. The Company is not requesting any changes to the Generation Rider or Renewable Rider.

WITNESS LIST

Q. Please identify the witnesses who will testify on behalf of Montana-Dakota in this proceeding.

A. The following witnesses will provide testimony and/or exhibits in support of the Company's application:

- Ms. Tammy J. Nygard, Controller for MDU Resources, will testify regarding the overall cost of capital, capital structure, and overall debt costs.
- Mr. Christopher M. Wall, Principal at The Brattle Group, will testify regarding the appropriate cost of common equity for Montana-Dakota's North Dakota electric operations and the appropriateness of the proposed capital structure.
- Mr. Robert Frank, Director of Electric Transmission Engineering for Montana-Dakota, will testify regarding transmission and substation capital expenditures.
- Mr. Brian Giggee, Director of System Operations and Planning for Montana-Dakota, will testify regarding the electric load forecast and the mobile radio system replacement project.

- Mr. Daryl Anderson, Director of Electric Distribution Services for Montana-Dakota, will testify regarding the electric distribution system (EDS) upgrades inclusive of wildfire mitigation efforts.
- Mr. Bradley J. Davison, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement, the interim revenue requirement, and proposed changes to the Transmission Rider.
- Mr. Ronald J. Amen, Managing Partner with Atrium Economics, LLC, will testify regarding the embedded class cost of service study and the proposed rate design.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota, will testify regarding proposed tariff changes and the derivation of interim rates.

AFFORDABILITY

Q. How does the Company view affordability for its customers in North Dakota?

A. Affordability is a core priority for Montana-Dakota. The Company recognizes that customers rely on its essential electric service, and is committed to providing that service at rates that remain reasonable and sustainable over the long term.

Q. How is that commitment reflected in Company operations?

A. It is reflected in every aspect of the business—from how it plans and executes capital investments, to how it manages operating costs, and how rates are designed. Montana-Dakota continually evaluates opportunities to control costs while maintaining the safety and reliability of the system.

Q. How do Montana-Dakota's electric rates in North Dakota compare to the rest of the United States?

A. Montana-Dakota's electric rates in North Dakota are competitive and remain below national averages. According to the Edison Electric Institute's latest survey of typical bills and average rates, the Company's North Dakota residential electric rates for the 12 months ending December 31, 2025, are the 7th lowest in the nation, out of 164 utilities surveyed.[1] The Company's relatively low rates translate into competitive monthly bills for residential customers.

Q. Why is that comparison important?

A. The comparison provides context for regulators and customers and reflects the Company's disciplined approach to cost management and operational efficiency. While all utilities face increasing cost pressures, it is important to demonstrate that Montana-Dakota customers continue to receive electric service at reasonable rates compared to other regions of the country.

[1] Edison Electric Institute, Typical Bills and Average Rates Report Winter 2026 (June 18, 2026).

Q. **How does the Company balance affordability with the need to provide safe and reliable service?**

A. That balance is central to the Company's role as a regulated utility. Montana-Dakota must ensure the system is safe and reliable, which requires ongoing investment, while making those investments in a prudent and disciplined manner to minimize impacts on customers.

Q. **What types of investments are necessary to maintain reliability?**

A. Investments are required across the system, including distribution infrastructure, system monitoring technologies, and equipment replacement. These investments help the Company continue to meet customer demand safely and reliably.

Q. **Are there factors outside the Company's control that impact customer rates?**

A. Yes. There are several external pressures, including inflation, supply chain constraints, and increases in material and labor costs, all of which impact the cost of providing service.

Q. **How does the Company respond to those cost pressures?**

A. The Company actively manages factors within its control—such as project prioritization and operational efficiency—while working to minimize the impact of external cost increases on customers.

Q. **Are there mechanisms in place that help offset costs for customers?**

A. Yes. The Company uses regulatory mechanisms that can provide credits or offsetting benefits to customers when available, like credits and offsets for wholesale sales and sales of Renewable Energy Credits. It is also notable that a portion of the revenues generated from certain large-load customers, such as a data center, are returned to North Dakota customers through rate mechanisms, helping to offset overall costs.

Q. What actions has the Company taken to manage or mitigate cost increases since the last rate case?

A. Montana-Dakota has taken a number of steps to manage costs, including prioritizing capital investments, reviewing operating expenses, and improving operational efficiency where possible. The Company has also evaluated staffing levels and organizational structure to ensure resources are aligned with operational needs. While these efforts have helped mitigate cost increases, external factors such as inflation, labor market pressures, and increased insurance and technology costs continue to impact the cost of providing service.

DATA CENTERS

Q. How are data centers integrated into the Company's electric system?

A. For purposes of this testimony, data centers discussed here will be limited to those that are taking service under Rate 45, which will be further defined below. All current data centers are integrated as large-load customers connected to the Company's electric transmission system. Depending on the specific project, they are served through existing infrastructure or through facilities that are directly assigned and paid for by the customer to serve that load. Operationally, these customers may participate in demand response programs and curtail load. Alternatively, they may procure their own capacity resources, for example on-site generation, during system constraints if they do not curtail load.

Q. Has the Commission previously considered how Montana-Dakota should provide service to data centers?

A. Yes. The Commission previously approved Montana-Dakota's High Density Contracted Demand Response Rate 45 tariff, which requires Electric Service Agreements (ESAs) between Montana-Dakota and customers requesting at least 10 MW of high density computer processing demand with a minimum load factor of 85 percent.[2] The rates provided in each ESA recover the incremental costs of providing service to the customer. Importantly, each ESA entered into by the Company under Rate 45 must be approved by the Commission.

Q. Does the Company rely on traditional rate-based investment to serve data centers?

A. No. The Company's approach has been to avoid placing large, data center-driven investments into rate base where those costs would be recovered from general customers. Instead, infrastructure required to serve these customers is either directly assigned or otherwise structured so that existing customers are not responsible for those costs. The Company also requires security and credit support in the ESA to mitigate

[2] *Montana-Dakota Utilities Co. High Density Contracted Demand Response Tariff and Rates*, Case No. PU-22-337, Order (Oct. 27, 2022).

the risk of these infrastructure costs being passed to general customers if the data center ceases operations earlier than expected.

Q. Are other customers paying for the costs associated with serving data centers?

A. No. The Company's approach ensures that other customers are not responsible for the costs associated with providing service to data centers. The Company has taken explicit steps to ensure that the costs to serve these loads are borne by the data center customers themselves.

Q. How was that principle applied in this rate case?

A. As further outlined in the testimony of Mr. Davison, the Company removed or adjusted out data-center-related costs from the revenue requirement used to set general customer rates. This ensures that traditional customers do not fund investments or expenses associated with serving those large loads.

Q. Why is that important from a regulatory perspective?

A. It follows cost causation principles and protects existing customers from subsidizing new, large-load customers. This approach maintains fairness and aligns with regulatory expectations around equitable cost allocation.

Q. If data center costs are excluded from the rate case, do those customers provide any benefit to others?

A. Yes. While their costs are isolated, the revenues data centers generate provide meaningful benefits to other customers.

Q. Please explain how those benefits are realized.

A. Customers benefit in two main ways. First, data centers help spread fixed system costs across more usage, which reduces the burden on all other customers. Specifically, data centers utilize the Company's electric transmission system. Montana-Dakota charges the data center as if they were a wholesale electric customer and they pay for transmission service based on the Company's MISO Attachment O rate. The transmission revenue is credited to customers annually through the Transmission Rider. To date, data centers have not used the Company's distribution system or generation assets. The second way customers benefit is through a portion of transaction charge revenue which is credited back to customers through the monthly Fuel and Power Cost Adjustment.

Q. Can you quantify the amount customers were credited from 2023 to 2025?

A. Yes. North Dakota customers received a total benefit of $38.4 million over the past three years. This amounts to an average annual savings of approximately $64 per customer.

Q. Does the Company's approach create risk for existing customers?

A. Actually, quite the opposite. The Company's approach is designed to reduce the risk related to serving large-load customers by ensuring (1) costs are directly assigned, and (2) benefits are shared with existing customers.

Q. What is the overall policy outcome of this approach?

A. The result is a model where:

- Data centers are responsible for the costs associated with serving their load;
- Existing customers are insulated from costs attributable to those loads; and
- Customers receive measurable financial benefits through credits to their rates.

Q. Is the Company proposing to make any changes to Rate 45 in this case?

A. No. The Company is not proposing any changes to Rate 45 in this case.

<u>REQUESTED COST RECOVERY</u>

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for an electric rate increase?

A. Montana-Dakota's current rates no longer reflect the cost of providing electric service to the Company's North Dakota customers. Since the last rate case, the Company has made substantial investments to maintain and enhance system reliability while also experiencing significant increases in operating costs. This filing is intended to support rates that more appropriately reflect those costs.

Q. When was the Company's last general rate case?

A. The Company's last rate case, Case No. PU-22-194, was filed in May 2022 and resulted in an overall revenue requirement increase of $15.3 million, or 7.4 percent. Final rates in that case became effective on July 1, 2023.

Q. What is the amount of the revenue increase requested in this case?

A. As further detailed by Mr. Davison and Mr. Amen, the Company is requesting a $34.5 million revenue increase, which represents a 14.5 percent overall increase, based on a projected 2027 test year.

Q. Previously you mentioned that Transmission Rider investments were transitioning to base rates. Please describe the requested increase.

A. The 14.5 percent increase reflects the combined effect of changes to the base rates and the Transmission Rider. More specifically, Montana-Dakota is proposing to transfer the plant in service previously authorized for recovery in the Transmission Rider to base rates.

Table 2: Net Bill Impact

Base Rate Bill Impact	18.1%
Transmission Rider Bill Impact	(3.6%)
Overall Bill Impact	14.5%

As noted in Table 2 above, the 14.5 percent overall increase reflects an 18.1 percent increase to base rates, partially offset by a 3.6

percent decrease to the Transmission Rider resulting from the movement of transmission plant-related costs to base rates.

Q. How would this increase affect the Company's residential customers?

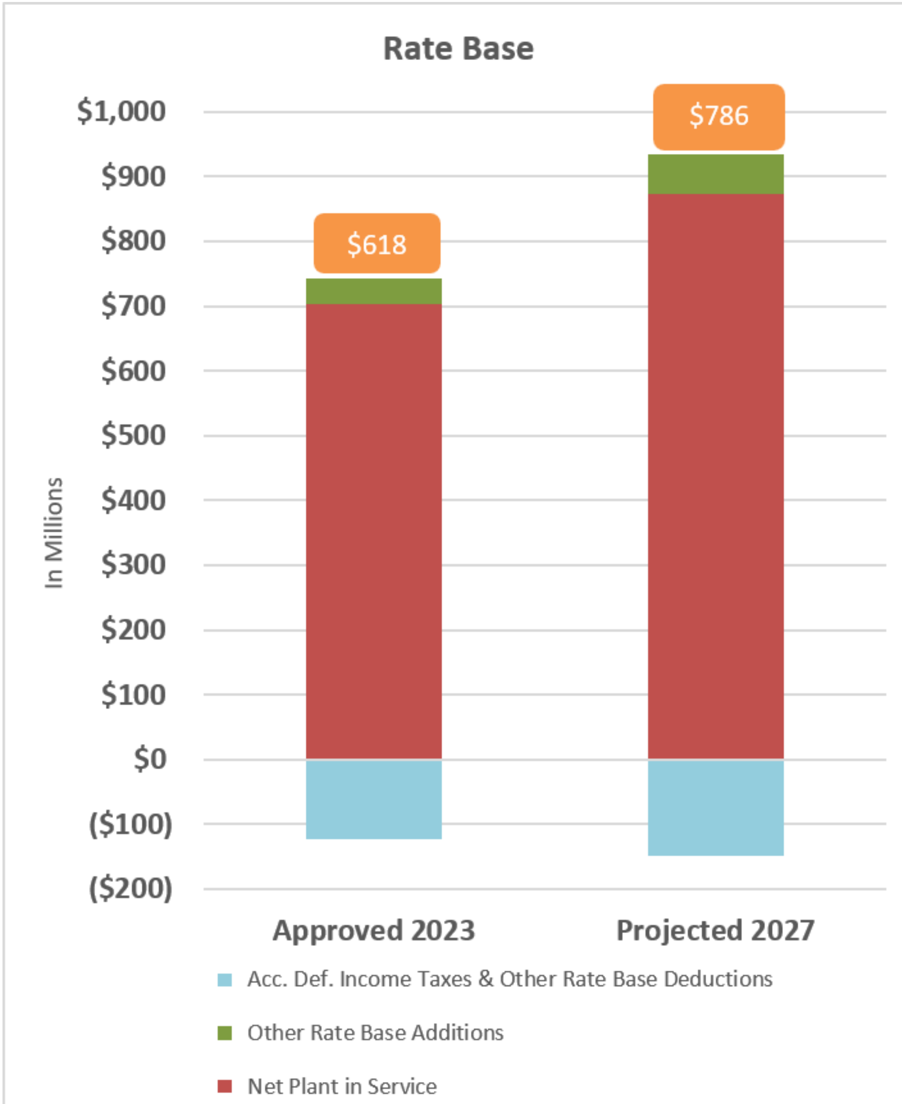
A. A residential customer would see a monthly increase of approximately $19.10 or 18.2 percent. This equates to an annual increase of approximately $229. This filing also includes an increase in the daily basic service charge from 50.1 cents per day ($15.24 monthly) to 98.8 cents per day ($30.05 monthly).

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. As noted earlier, the last rate increase was implemented July 1, 2023, based on a projected 2023 revenue requirement. Since that time, the Company has experienced meaningful increases in both capital investment and operating expenses.

The additional investments have increased rate base, which in turn has increased depreciation expense and property taxes. As illustrated in Figure 3 below, the Company's net adjusted projected rate base is anticipated to increase by approximately $167.1 million or 27 percent, relative to the 2023 approved level.

Figure 3: Rate Base



In addition, and as shown in Table 3, projected operations and maintenance (O&M) expenses, excluding fuel and purchased power, have increased approximately 29 percent when compared to the approved December 31, 2023 rates, which is a 6.5 percent compounded annual growth rate.

Table 3: Change in Total O&M Excluding Fuel and Purchased Power

	Approved 2023	Projected 2027	Variance	% Variance
Labor	$21,936,286	$27,375,855	$5,439,569	25%
Benefits	3,974,217	6,360,868	2,386,651	60%
Big Stone/Coyote	7,834,280	8,932,115	1,097,835	14%
Insurance	2,824,554	3,835,127	1,010,573	36%
Software Maintenance	2,159,925	4,340,924	2,180,999	101%
Other O&M	14,632,017	17,843,359	3,211,342	22%
Total O&M	$53,361,279	$68,688,248	$15,326,969	29%

Q. What are the primary drivers of the increases in O&M expenses between this case and the previous case?

A. The primary drivers are increases in labor and benefits driven by changes in the labor market. Insurance and software maintenance costs have also increased due to higher insurance premiums, increased software licensing costs, and enhanced cybersecurity requirements.

Q. How have the Company's labor expenses changed since the last case?

A. Montana-Dakota's projected labor expenses for the year ending December 2027 are approximately 25 percent, or a 5.7 percent compounded annual growth rate, higher than the level reflected in approved rates as of December 31, 2023.

This increase reflects sustained labor market pressure across the Company's service territory. Like many employers, Montana-Dakota is operating in a competitive hiring environment characterized by low unemployment and an increasing share of the workforce reaching retirement age. These conditions have increased the cost of attracting and retaining qualified employees, particularly in entry-level, skilled trade, and other specialized positions that are essential to safe and reliable utility operations.

Labor expense has also been affected by collectively bargained wage adjustments. On March 18, 2024, Montana-Dakota finalized its labor contract with the System Council U-13 of the International Brotherhood of Electrical Workers covering the period through April 2026. The Company is currently finalizing a successor agreement expected to remain in effect through April 30, 2029. The first-year increase, effective April 20, 2026, provides for an approximate 6 percent increase in labor expense. This increase is necessary for the Company to remain competitive in the labor market and retain skilled employees capable of maintaining safe and reliable service for customers. The effect of the contract is further discussed in the testimony of Mr. Davison.

Q. How have the Company's benefit expenses changed since the last case?

A. The increase in benefit expenses since the last case is primarily driven by higher pension expense and increased 401(k) costs. Pension expense has increased due to changes in actuarial assumptions and market conditions, while 401(k) expense has increased in line with higher labor costs and an increase to the Company's matching contribution.

These benefit-related changes are discussed in more detail in the testimony of Mr. Davison.

Q. What investments has the Company made since Case No. PU-22-194?

A. Montana-Dakota invested approximately $256 million from 2023 through 2027. The investments have included:

- Production investments recovered in base rates increased approximately $15 million from 2023 through 2027.
- Transmission investments increased approximately $124 million from 2023 through 2027, including upgrades to aging substations and transmission lines, as well as line projects undertaken to enhance system reliability. Approximately $81 million of these investments are currently being recovered through the Company's Transmission Rider.
- Distribution investments increased approximately $79 million, which include upgrading substations, replacing or upgrading transformers, replacing or upgrading distribution lines and reliability projects to maintain service to customers.
- General and Common investments increased approximately $38 million, with larger investments coming from work equipment, mobile radio systems, software and hardware additions, building and shop upgrades.

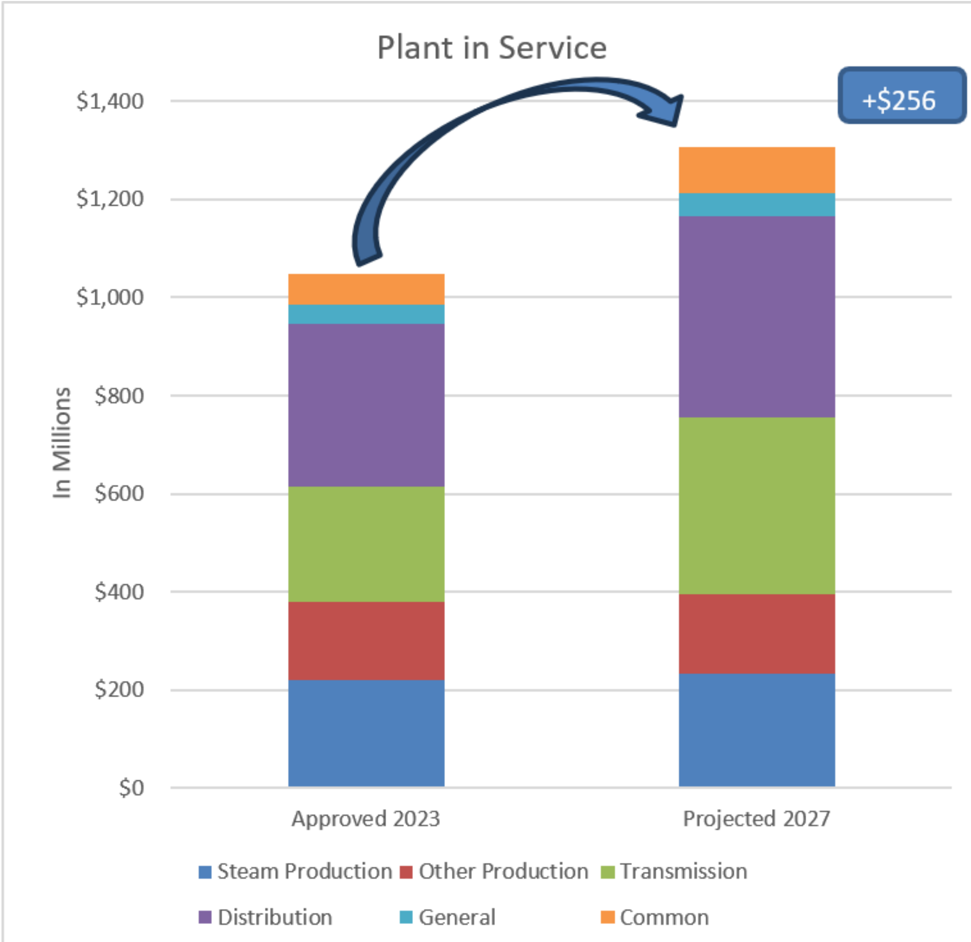
Q. What incremental investments are included in this case as projected for 2026 and 2027?

A. The Company is projecting $126 million of incremental investments in 2026 and 2027. More specifically, these investments include:

- Production investments of approximately $12 million, which include minor construction projects, generator rotor rewind, and exciter replacement;
- Transmission investments of approximately $31 million including the Merricourt and Stanley Substation additions and the Lignite – Kinkaid Line as discussed in greater detail by Mr. Frank;
- Distribution investment of approximately $49 million including EDS upgrades associated with wildfire mitigation efforts, as discussed in greater detail by Mr. Anderson;
- General and common plant additions of approximately $33 million are primarily associated with work equipment, software systems, structural building construction, and the mobile radio system replacement, as discussed in greater detail by Mr. Davison and Mr. Giggee.

Figure 4 below shows the investment in plant assigned and allocated to North Dakota electric operations from 2023 to projected 2027 and included in this case.

Figure 4: Projected Increase in Plant in Service



Q. Have you performed a depreciation study for inclusion in this request?

A. Yes. A depreciation study for Montana-Dakota's common plant was performed by Mr. Larry Kennedy of Concentric Advisors, ULC and based on plant in service as of December 31, 2021. The impact of the depreciation study results in a revenue requirement increase of approximately $807,000 compared to the previously approved rates. Further discussion of these changes is provided in the testimony of Mr. Davison.

The remaining electric depreciation rates are the same as those approved in Case No. PU-22-194.

Q. What rate of return is Montana-Dakota requesting in this case?

A. As supported in Ms. Nygard's testimony, Montana-Dakota is requesting an overall return of 7.996 percent, inclusive of a return on equity (ROE) of 10.8 percent. As presented in the testimony of Mr. Wall, a 10.8 percent ROE is fully justified and supported based on the results of his studies.

Q. You have discussed a number of items, can you briefly summarize the additional revenue requirement?

A. In summary, as shown in the table below, the $34.5 million increase in revenue is driven primarily by:

Table 4: Change in Revenue Requirement

Amount (in millions)	Revenue Requirement
Incremental Rate Base	$15.3
Operating Income Items:	
Margin	(2.2)
Other Revenue	(1.3)
O&M	15.4
Depreciation Expense	6.5
Other Taxes	0.8
Revenue Requirement Increase	$34.5

Q. How will the requested increase affect the various customer classes?

A. The allocation of revenue is based on the Class Cost of Service Study supported by Mr. Amen. The proposed percentage change in rates by customer class is as follows:

Table 5: Rate Change by Customer Class

Rate Class	Base Bill Impact	Transmission Rider Bill Impact	Overall Bill Impact
Residential	22.7%	(3.8%)	18.9%
Small General Service	17.2%	(3.2%)	14.0%
General Service	14.7%	(3.6%)	11.1%
Public Lighting	11.9%	(1.6%)	10.3%
Municipal Pumping	15.4%	(3.9%)	11.5%
Outdoor Lighting Service	31.3%	(1.4%)	29.9%
Total North Dakota Electric	**18.1%**	**(3.6%)**	**14.5%**

Q. Is Montana-Dakota seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with North Dakota Century Code 49-05-06. Montana-Dakota's overall rate of return on its investment was 5.81 percent as of December 31, 2025, resulting in a return on equity of 6.71 percent, which is below the authorized return of 9.75 percent. The amount of interim relief sought is $26,347,265 or 13.83 percent and consists of the Company's projected 2027 revenue requirement adjusted to reflect the return on equity of 9.75 percent authorized in Case No. PU-22-194 and the exclusion of items that were not a part of the last rate case settlement.

The interim request will be described in more detail by Mr. Davison. The proposed interim rates are described by Ms. Bosch. The interim increase is necessary to provide the Company an opportunity to recover the costs of providing service to customers today.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable. They are reflective of the total costs being incurred by Montana-Dakota to provide safe and reliable electric service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its North Dakota electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony

Of

Tammy J. Nygard

Q. Please state your name and business address.

A. My name is Tammy J. Nygard and my business address is 1200 West Century Avenue, Bismarck, North Dakota 58503.

Q. By whom are you employed and in what capacity?

A. I am the Controller for MDU Resources Group, Inc. (MDU Resources), which includes Montana-Dakota Utilities Co. (Montana-Dakota or Company), a wholly owned subsidiary of MDU Resources.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I am responsible for providing leadership and management of the accounting function and support financial forecasting and planning activities, including the analysis and reporting of all financial transactions.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 24 years of experience in the utility industry. During my tenure with the

Company, I have held positions of increasing responsibility, including Financial Analyst , Director of Accounting and Finance, and Controller for Montana-Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports the Company's proposed capital structure, cost of debt, and overall rate of return as reflected in Statement E.

Q. Was this statement and the data contained therein prepared by you or under your supervision?

A. Yes, it was.

Q. Is it true to the best of your knowledge and belief?

A. Yes, it is.

Q. Would you please explain Statement E?

A. Statement E shows the utility capital structure of Montana-Dakota for the twelve months ended December 31, 2025, and the projected capital structure for 2026 and 2027. Statement E includes the associated costs of debt and common equity. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.996 percent. This recommended rate of return balances investor and customer interests and supports the Company's ability to attract capital on reasonable terms. I rely on and adopt Mr. Christopher M. Wall's recommended 10.8 percent return on equity for the purposes of this calculation.

Statement E summarizes the utility capital structure and the related utility costs of capital on December 31, 2025, and the projected capital structure and the related utility costs of capital for 2026 and 2027. The components of the 2027 projected overall annual rate of return, which are used by Mr. Bradley J. Davison to calculate the revenue requirement, are:

	Ratio	Cost	Weighted Cost of Capital
Long Term Debt	45.053%	5.207%	2.346%
Short Term Debt	4.788%	4.867%	0.233%
Common Equity	50.159%	10.800%	5.417%
Rate of Return	100.000%		7.996%

Q. How does the Company finance its electric utility operations and determine the amount of common equity and debt to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made, and plans to make, significant capital investments in utility plant across its service territory. These investments include new generation resources to support capacity and energy needs, such as the 122.5 MW Badger Wind Project (Badger Wind) acquired December 31, 2025, as well as ongoing substation and transmission system upgrades, replacement of the mobile radio system, and other projects to enhance system reliability and support wildfire mitigation efforts. These new investments also have associated operating and maintenance costs.

Through its financial planning process, the Company determines the financing needed to support these activities. Montana-Dakota finances its operations targeting a 50 percent common equity capital structure at year end. The Company finances capital expenditure investments through a mix of internally generated funds, the utilization of its short-term credit line, and the issuance of additional debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

On October 28, 2025, the Company entered into a $250.0 million note purchase agreement with $150.0 million issuance October 28, 2025, and a delayed draw of $100.0 million that was funded on February 2, 2026.

On December 30, 2025, the Company entered into a $250.0 million term loan agreement for the Badger Wind Project. In February 2026 and March 2026, the Company paid down $100.0 million and $80.0 million of the outstanding balance under the term loan agreement, with the remaining pay down of this agreement to occur later in 2026.

The Company has a total of $140.0 million of senior notes maturing in July and August 2026 and expects to issue $200.0 million of long-term debt in August 2026, partially to replace the senior notes maturing. The Company is also projecting to issue $130.0 million of new long-term debt in 2027.

The Company obtained $80.0 million of additional common equity in March 2026. In addition, the Company expects to receive approximately $40.0 million of common equity in late 2026 and $115.0 million of common equity in 2027 in order to achieve and maintain the targeted capital structure.

Q. Were there any adjustments made to the debt in the rate of return calculation? If so, please explain.

A. As described above, the Company entered into a $250.0 million term loan agreement on December 30, 2025, related to the acquisition of Badger Wind. This debt is being converted to long-term debt and equity in 2026. Therefore, since this $250.0 million note outstanding at December 31, 2025, is being converted to long-term debt and equity in 2026, the $250.0 million was excluded from long-term debt in this case to ensure the capital structure used for ratemaking reflects the expected long-term financing of the project.

Q. What does Statement E, Schedule E-1 show?

A. Page 1 is a summary showing the Company's long-term debt on December 31, 2025, and associated cost of debt, and it shows the projected long-term debt and associated costs for 2026 and 2027. Page 2 shows the cost and the debt balance by issue on December 31, 2025. Page 3 shows the projected cost and the debt balance by issue on December 31, 2026, and page 4 shows the projected cost and the debt balance by issue on December 31, 2027.

Q. How did you derive the projected cost of debt for 2026 and 2027?

A. The projected cost of debt for 2026 and 2027 is based upon the yield-to-maturity of each debt issue outstanding and projected to be outstanding.

Q. Would you please describe Statement E, Schedule E-2?

A. Schedule E-2 presents the twelve-month average short-term debt balance for 2025 and projected average balance for 2026 and 2027, as well as the average and projected cost of short-term debt. The Company uses a twelve-month average of short-term debt in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement E, Schedule E-3 show?

A. The schedule presents the common equity balance on December 31, 2025, and the projected balance for December 31, 2026, and December 31, 2027, reflecting the projected activity in the balance.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No.__(CMW-1)

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-26-___

PREPARED DIRECT TESTIMONY OF

CHRISTOPHER M. WALL

Q1. Please state your name and business address.

A1. My name is Christopher M. Wall. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony before the North Dakota Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co, which is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"). My testimony addresses the regulated electric utility operations of Montana-Dakota Utilities Co. within North Dakota ("Montana-Dakota" or the "Company").

Q3. Please describe your background and professional experience in the energy and utility industries.

A3. I hold a B.A. in Mathematics and Economics from Saint Peter's College and a Master's degree in Economics from Northeastern University. I have fifteen years of experience consulting in the energy industry and have been involved with a variety of projects, mostly involving cost of capital; cost of service; demand forecasting; and rate design for natural gas, water, and electric utilities in North America. I have been involved in over 100 assignments focused on the determination of the cost of capital for ratemaking purposes. I have also included my resume and a summary of the testimony I have filed in other proceedings in Exhibit No.___ (CMW-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. What is the purpose of your direct testimony?

A4. The purpose of my direct testimony is to present evidence and provide a recommendation regarding Montana-Dakota's return on equity ("ROE") for its electric utility operations to be used for ratemaking purposes. I also address the appropriateness of the Company's proposed capital structure. My analyses and recommendations are supported by the data presented in Exhibit No. ___(CMW-2), Schedules 2 through 11, which were prepared by me or under my direction.

Q5. Please provide a brief overview of the analyses that support your ROE recommendation.

A5. I estimate the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also considers the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q6. How is the remainder of your direct testimony organized?

A6. The remainder of my direct testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII provides an assessment of the reasonableness of the Company's proposed capital structure.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q7. Please summarize the key factors that you consider your analyses and upon which you base your recommended ROE.

A7. My analyses and recommendations consider the following:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

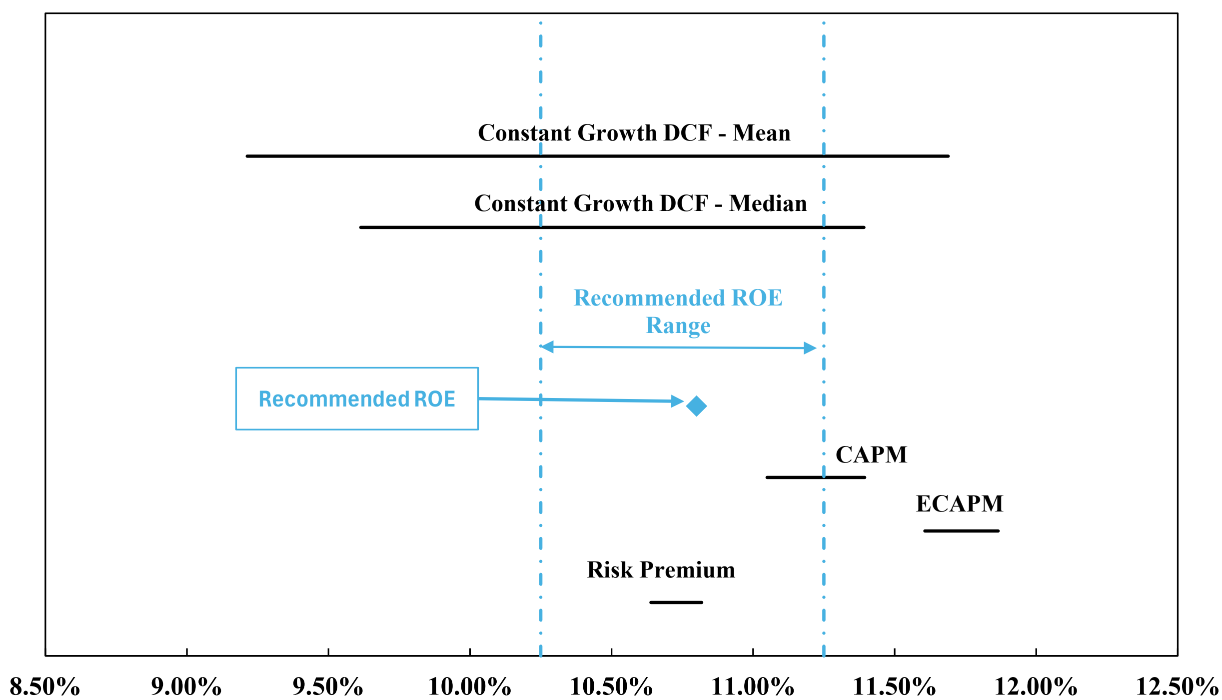
[1] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q8. What are the results of the models that you have used to estimate the market-based cost of equity for Montana-Dakota?

A8. Figure 1 summarizes the range of results produced by the cost of equity analyses based on market data through April 30, 2026.

Figure 1: Summary of Cost of Equity Analytical Results



Q9. What is your recommended ROE for the Company in this proceeding?

A9. Considering the analytical results of the market-based cost of equity models and current and prospective capital market conditions, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. Within my recommended range, I recommend an ROE of 10.80 percent, which is slightly above the midpoint of the range due to the fact that the Company has greater business risk relative to the proxy group companies.

Q10. Is the Company's requested capital structure reasonable?

A10. Yes. The Company's proposed 50.185 percent common equity ratio for the rate year ending December 31, 2026 and 50.159 percent common equity ratio for the rate year ending December 31, 2027 are well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies and are below the average of the proxy group.

III. REGULATORY GUIDELINES

Q11. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A11. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates. [2]

Q12. How did the Court connect achieving a fair rate of return to providing utility service to customers?

A12. The Court stated in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[3] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[4]

Q13. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A13. An authorized ROE that is adequate to attract capital at reasonable terms enables a utility to continue to provide safe, reliable service while maintaining its financial integrity. The authorized return should be commensurate with returns expected elsewhere in the market for investments of comparable risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost. When the Company is afforded a reasonable opportunity to earn its market-based cost of capital, a fair and reasonable balance is achieved between customers' and shareholders' interests.

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[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

[3] *Bluefield*, 262 U.S. at 679, 693.

[4] *Hope*, 320 U.S. at 591, 603.

Q14. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A14. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a wholly-owned subsidiary of MDU, the Company competes with the other MDU subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU to consider the authorized ROE of each of its subsidiaries.

Q15. What is the standard for setting the ROE in any jurisdiction?

A15. The stand-alone ratemaking principle is a foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. Consistent with this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for Montana-Dakota's electric operations in North Dakota.

Q16. Does the fact that the Company is a subsidiary of MDU, a publicly-traded company, affect your analysis?

A16. No. In this proceeding, consistent with the stand-alone ratemaking principle, it is appropriate to establish the cost of equity for the Company, not its publicly-traded entity, MDU. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the Company the ability to attract capital on reasonable terms on a stand-alone basis and within MDU.

Q17. Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A17. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for reinforcing a utility's creditworthiness and financial stability in the jurisdiction. To the extent authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the utility operates.

Q18. What are your conclusions regarding regulatory guidelines?

A18. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. Capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the models to estimate the required return for the subject company.

Analysts and regulatory commissions recognize the importance of considering how these conditions impact cost of equity estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return of the forward-looking period.

Q20. What has the level of inflation been over the past few years?

A20. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.38 percent in January 2021 to a high of 6.62 percent in September 2022, which was the largest 12-month increase since 1982.[5] Although core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.00 percent.

Because the Federal Reserve's dual mandate is to promote stable prices and employment, considering employment data, in addition to inflation, is important. The ratio of unemployed persons per job opening was 1.0 in April 2026 (the most recent data available at the time of this testimony). While the ratio of unemployed persons per job opening increased slightly in recent months, it has been consistently at or below 1.1 since March 2021, which suggests a tighter labor market. The strength in the labor market allowed the Federal Reserve to prioritize reducing inflation by pursuing the restrictive monetary policy needed to achieve its 2.00 percent target benchmark.

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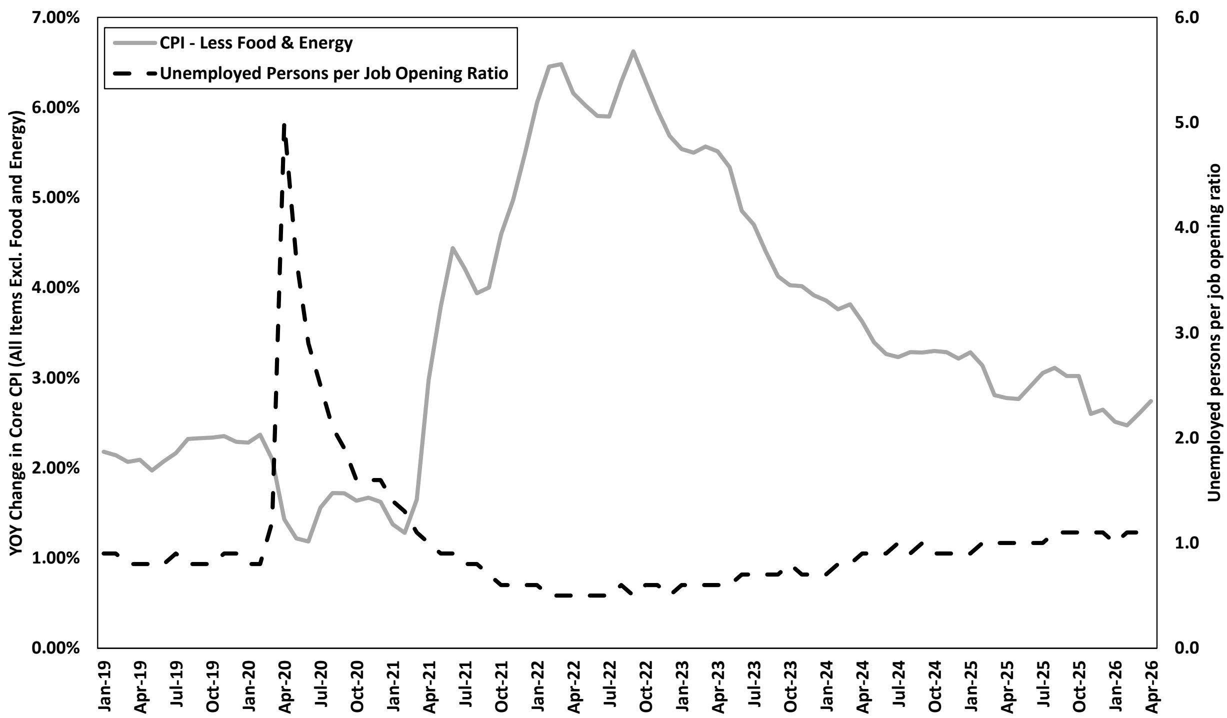
[5] *Bloomberg,* Pickert, Reade, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike", October 13, 2022.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to April 2026[6]



Q21. What policy actions did the Federal Reserve enact to respond to increased inflation?

A21. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent.

6 Bureau of Labor Statistics; reflects data available as of June 8, 2026. The data for Core Inflation was available through April 2026. The last month that was published for Unemployed persons to job openings was April 2026. Figure 2 presents the year-over-year change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I have considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

Q22. How did yields on long-term government bonds respond to the Federal Reserve's normalization of monetary policy?

A22. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has increased by over 350 basis points, increasing from 1.47 percent on December 15, 2021, to a peak of 4.98 percent on October 19, 2023. It currently remains well above 2021 levels (*i.e.,* 4.45 percent as of June 5, 2026).[7]

Q23. Has the Federal Reserve reduced the federal funds rate?

A23. Yes. The Federal Reserve reduced the federal funds rate by 50 basis points in September 2024, 25 basis points in November 2024, 25 basis points in December 2024, and more recently 25 basis points in September 2025, October 2025 and December 2025. While the Federal Reserve kept rates unchanged through the first five meetings in 2025, its decision to reduce the federal funds rate at the final three meetings in 2025 was due to an increase in the downside risk to employment in recent months.[8]

Q24. What is the expected path of monetary policy over the near-term?

A24. At the June 2026 FOMC meeting, Chair Warsh noted that economic activity was expanding at a "solid pace" despite uncertainty due to the conflict in Iran, "job gains have kept pace with the workforce" and the unemployment rate has remained steady.[9] Chair Warsh did acknowledge that inflation has been above the Federal Reserve's 2 percent target for more than five years and that "high prices" are a "burden for the American people"; however, he

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7 S&P Capital IQ Pro.

8 Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, September 17, 2025, October 29, 2025, and December 10, 2025.

9 Federal Reserve, "Transcript of Chairman Warsh's Press Conference," June 17, 2026.

noted that the FOMC will "deliver price stability".[10] Considering the current economic conditions, the FOMC decided to maintain the federal funds rate range of 3.50 percent to 3.75 percent.[11] While Chair Warsh did not comment on the possible path of monetary policy, the FOMC did publish a forecast at the June 2026 meeting, where the median federal funds rate projection was 3.8 percent for 2026 and 3.6 percent for 2027.[12] Thus, the FOMC currently expects the federal rate to remain steady over the near-term.

Q25. What has happened to the yields on long-term government bonds since the FOMC reduced the federal funds rate in September 2024?

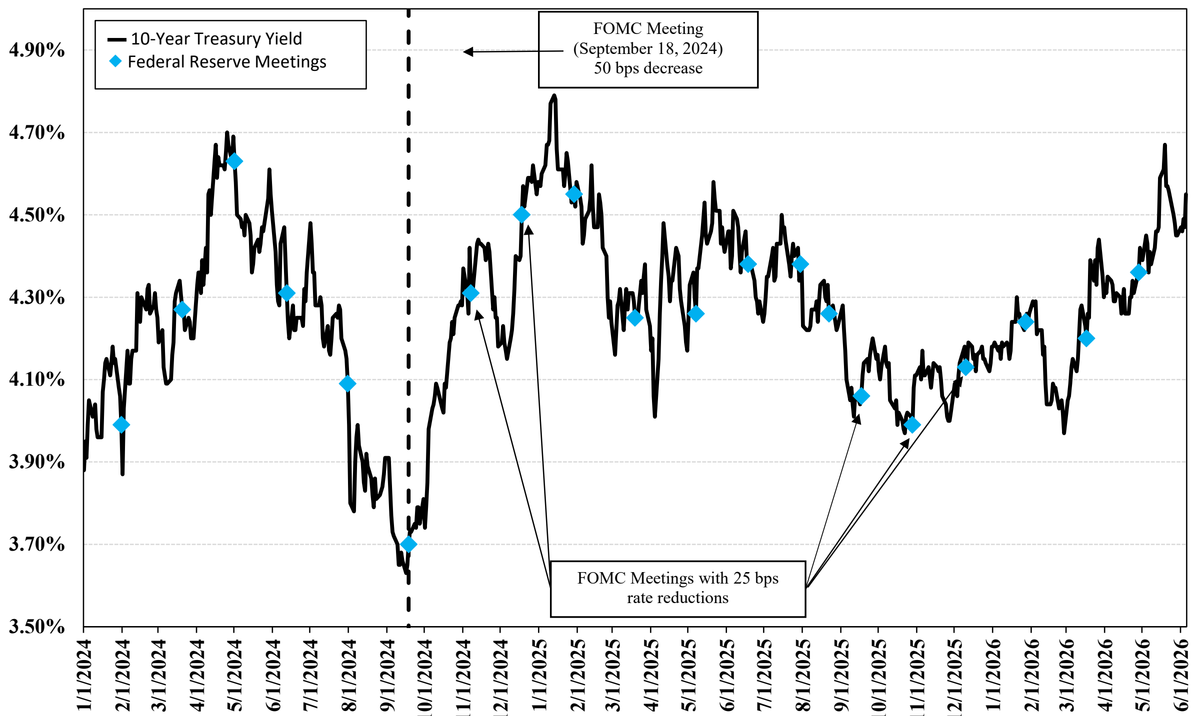
A25. As shown in Figure 3 below, although the yield on the 10-year treasury bond declined prior to the time of the first federal funds rate cut, the yield has generally increased since the September 2024 FOMC meeting. Further, while the yield on the 10-year Treasury bond has been volatile recently, as of June 5, 2026, the 10-year Treasury bond yield was 4.55 percent, which is generally consistent with levels seen in May 2024, four months prior to the first reduction in the federal funds rate.

[10] *Id.*

[11] *Id.*

[12] Federal Reserve, "Summary of Economic Projections", June 17, 2026.

Figure 3: 10-Year Treasury Bond Yield, Janaury 2024 through June 5, 2026[13]



Q26. Why have long-term interest rates remained above the levels at the time the Federal Reserve first reduced the federal funds rate in September 2024?

A26. Ongoing policies of the current administration's economic plans have resulted in higher deficits, and persistent inflation. For example, since January 2025, the administration announced several sets of tariffs on each of the U.S.'s trading partners. [14] The implemented tariffs are largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bond payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on those bonds increase.

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[13] *S&P Capital IQ Pro*.

[14] Jennifer Clarke, "What Are Tariffs, How Do They Work and Why Is Trump Using Them?" *BBC News*, August 27, 2025.

The longer the duration of the bond, the greater the effect of inflation which is why inflation risk is greater for long-term government bonds. The significant tariff policy increases the risk that inflation will remain elevated, which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve first reduced the federal funds rate in September 2024. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[15]

Q27. What effect does the recent U.S. Supreme Court ruling have on the tariffs implemented by the administration in 2025?

A27. On February 20, 2026, the U.S. Supreme Court ruled that the tariffs implemented in 2025 under the International Emergency Economic Powers Act ("IEEPA") were illegal. However, the administration responded to the ruling by imposing a 15.00 percent tariff on all goods imported into the U.S. under Section 122 of the 1974 Trade Act.[16] Section 122 of the 1974 Trade Act allows a President to implement global tariffs up to 15.00 percent for a period of five months after which the approval of Congress is needed for continuation of the tariffs. Therefore, the administration is still able to at least temporarily impose global tariffs, which as noted above will continue to place upward pressure on prices.

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[15] Karishma Vanjani, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," *Barron's*, April 9, 2025.

[16] Dearbail Jordan, "Trump says he will increase his new global tariffs to 15%," BBC, February 22, 2026.

Q28. Have there been any other recent developments that may affect inflation and long-term government bond yields?

A28. Yes. The conflict in Iran and the resulting increase in underlying oil prices has put upward pressure on inflation as increased oil prices not only increase gasoline prices for consumers, but also the prices of other products as well given that nearly all goods need to be transported from the place of production. The likelihood of continued elevated inflation suggests interest rates are expected to remain higher in the near term.[17] In fact, as shown in Figure 3, since the start of the conflict in Iran, the yield on the 10-year Treasury bond has increased 58 basis points from 3.97 percent on February 27, 2026 to 4.55 percent on June 5, 2026.

Q29. What are the expectations for the yields on long-term government bonds?

A29. Economists are still expecting elevated long-term interest rates. In the most recently published report by *Blue Chip Financial Forecasts*, the consensus estimate of economists is that the 30-year treasury bond yield will remain relatively stable and decrease only slightly from 4.90 percent in Q2/2026 to 4.80 percent in Q3/2027.[18] Additionally, the consensus estimate over the longer-term (*i.e.*, 2027–2031) is 4.60 percent.[19] This is important because it means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

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[17] *See, e.g.*, Finbar Flynn and Ruth Carson, "Bonds Lose $2.5 Trillion in Iran War Wipeout That Mirrors 2022" *Bloomberg*, March 23, 2026.

[18] *Blue Chip Financial Forecasts*, Vol. 45, No. 5, May 1, 2026, at 2.

[19] *Blue Chip Financial Forecasts*, Vol. 44, No. 12, December 1, 2025, at 14.

Q30. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A30. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. While the FOMC reduced the federal funds rate several times in late 2025, the FOMC's current projections are for the federal funds rate to remain at the current level over the near-term. Further, long-term interest rates remain elevated and are expected to continue to remain elevated due to inflationary policies such as tariffs and tax cuts and the uncertainty regarding the Iran conflict and the increase in underlying energy costs. With long-term interest rates expected to remain relatively high, borrowing also remains relatively more expensive, and thus investors also demand a relatively high cost of capital, which means the cost of capital also remains relatively high.

V. PROXY GROUP SELECTION

Q31. Please provide a brief profile of Montana-Dakota.

A31. Montana-Dakota is a wholly owned subsidiary of MDU. The Company provides electric service to approximately 94,700 customers in North Dakota.[20] As of December 31, 2025, the Company's net utility electric plant in North Dakota was approximately $1.11 billion.[21] In addition, the Company had total electric sales in North Dakota in 2025 of approximately 3.51 billion kWh.[22] North Dakota accounted for 67 percent of electric retail revenues for

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[20] Montana-Dakota Utilities, 2025 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 7.

[21] Montana-Dakota Utilities, 2025 Annual Report to the North Dakota Public Service Commission, I. Intrastate Return on Equity, Line No. 3.

[22] Montana-Dakota Utilities, 2025 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 13.

MDU in 2025.[23] Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Stable) from S&P, Baa1 (Outlook: Stable) from Moody's and BBB+ (Outlook: Stable) from Fitch Ratings ("Fitch").[24]

Q32. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A32. In this proceeding, the cost of equity is being estimated for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and the Company's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if the Company was a publicly-traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company and thus provide a reasonable basis to estimate the appropriate cost of equity for the Company.

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[23] MDU Resources Group, Inc., SEC Form 10-K, 2025, at 13.

[24] S&P Global Ratings, Moody's and FitchRatings, as of June 9, 2026.

Q33. How did you select the companies included in your proxy group?

A33. I began with the universe of companies that *Value Line Investment Survey* ("*Value Line*") classifies as Electric Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the DCF model;
- have investment grade long-term issuer ratings;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are included in rate base;
- derive more than 40.00 percent of their megawatt-hour sales from their owned generation facilities;
- derive more than 60.00 percent of their total operating income from regulated electric operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q34. What is the composition of your proxy group?

A34. The screening criteria, discussed above, is shown in Exhibit No.___(CMW-2), Schedule 3 and results in a proxy group consisting of the companies shown in Figure 4.

Figure 4: Proxy Group[25]

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q35. Please briefly discuss the ROE in the context of the regulated rate of return.

A35. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

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25 On May 18, 2026, NextEra Energy, Inc. announced the acquisition of Dominion Resources, Inc. for $67.4 billion. While the transaction occurred after the end the analytical period (*i.e.,* April 30, 2026), I excluded both companies from the proxy group used to develop the cost of equity for Montana-Dakota.

Q36. How is the required cost of equity determined?

A36. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q37. What methods did you use to estimate the cost of equity for the Company in this proceeding?

A37. I consider the results of the constant growth form of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q38. Is it important to use more than one analytical approach?

A38. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[26] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[27] recommend the CAPM, DCF, and BYRP approaches.

A. Constant Growth DCF Model

Q39. Please describe the DCF approach.

A39. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

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26 Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* (3rd ed. 2000), at 214.

27 Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* (7th ed. 1994), at 341.

Q40. What assumptions are required for the constant growth DCF model?

A40. The constant growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q41. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A41. The dividend yield in my constant growth DCF model is based on the proxy companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of April 30, 2026.

Q42. Why did you use three averaging periods for stock prices?

A42. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q43. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A43. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q44. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A44. In its constant growth form, the DCF model (*i.e.*, Equation [2] shown previously) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q45. What sources of long-term growth rates did you rely on in your constant growth DCF model?

A45. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) Zacks Investment Research (*Zacks*); (2) S&P Capital IQ; and (3) *Value Line*.

Q46. Have you previously relied on projected EPS growth rates provided by *Yahoo! Finance*?

A46. Yes, however, *Yahoo! Finance* no longer reports consensus projected 3- to 5-year EPS growth rates. As a result, I now instead rely on the consensus projected 3- to 5-year EPS growth rates reported by *S&P Capital IQ*.

Q47. How do you calculate the range of results for the constant growth DCF models?

A47. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, *S&P Capital IQ*, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q48. Please summarize the results of your constant growth DCF analyses.

A48. Exhibit No.___(CMW-2), Schedule 4 and Figure 5 summarize the results of the constant growth DCF models.

Figure 5: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.10%	10.46%	11.57%
90-Day Avg. Stock Price	9.22%	10.59%	11.70%
180-Day Avg. Stock Price	9.32%	10.68%	11.80%
Average	**9.21%**	**10.58%**	**11.69%**
Median Results:			
30-Day Avg. Stock Price	9.46%	10.48%	11.32%
90-Day Avg. Stock Price	9.61%	10.58%	11.42%
180-Day Avg. Stock Price	9.77%	10.71%	11.44%
Average	**9.61%**	**10.59%**	**11.39%**

B. CAPM and ECAPM Analyses

Q49. Please briefly describe the Capital Asset Pricing Model.

A49. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[28] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

[28] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

K_e = the required market cost of equity;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q50. What risk-free rate did you use in your CAPM analyses?

A50. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.91 percent;[29] (2) the average projected 30-year U.S. Treasury bond yield for the third quarter of 2026 through the third quarter of

[29] Bloomberg Professional, as of April 30, 2026.

2027, which is 4.82 percent;[30] and (3) the average projected 30-year U.S. Treasury bond yield for 2027 through 2031, which is 4.60 percent.[31]

Q51. What beta coefficients did you use in your CAPM analysis?

A51. As shown in Exhibit No.___(CMW-2), Schedule 5, I use the beta coefficients for the proxy group companies as reported by *Value Line*. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit No.___(CMW-2), Schedule 6, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2025.

Q52. How do you estimate the market risk premium in the CAPM?

A52. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown on Exhibit No.___(CMW-2), Schedule 7, the expected return on the S&P 500 Index is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.31 percent and a weighted long-term growth rate of 11.89 percent, the estimated required market return for the S&P 500 Index as of April 30, 2026 is 13.28 percent.

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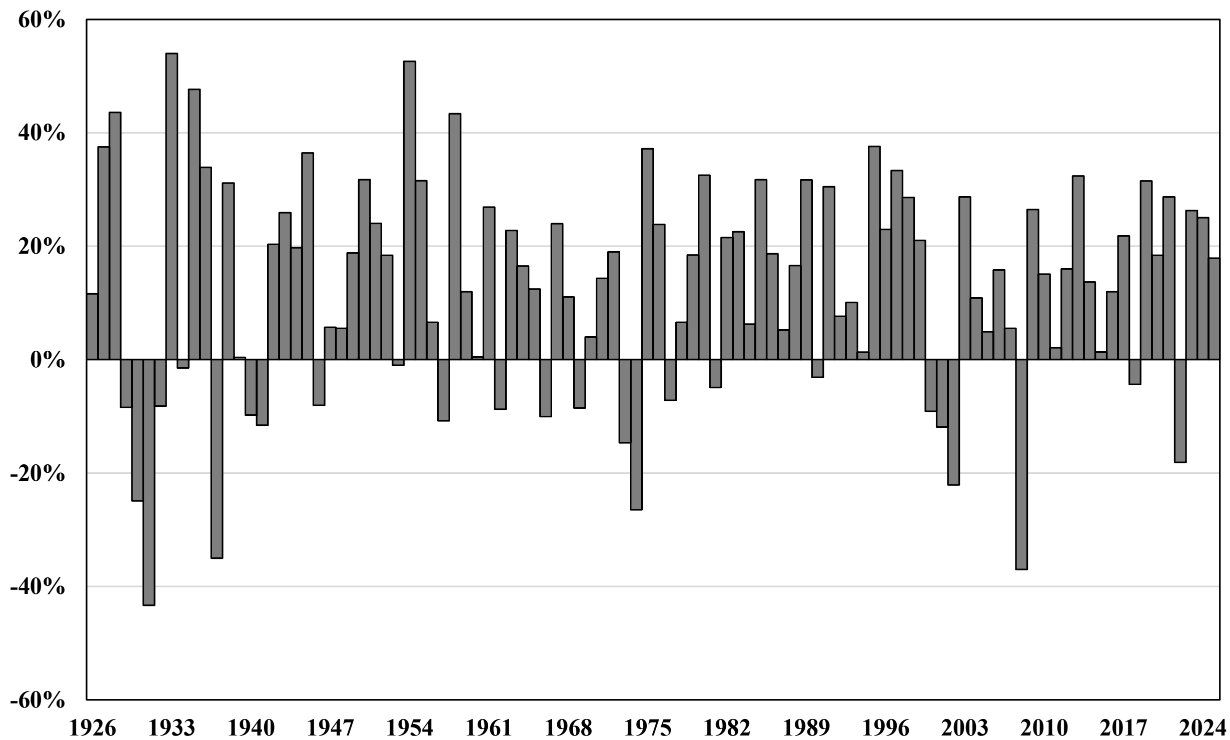
30 *Blue Chip Financial Forecasts,* Vol. 45, No.5, May 1, 2026, at 2.

31 *Blue Chip Financial Forecasts*, Vol. 44, No. 12, December 1, 2025, at 14.

Q53. How does the expected market return compare to observed historical market returns?

A53. As show in Figure 6, given the range of annual equity returns that have been observed over the past century, a current expected market return of 13.28 percent is reasonable. In 53 out of the past 100 years (or approximately 53.00 percent of observations), the realized equity market return was at least 13.28 percent or greater.

Figure 6: Realized U.S. Equity Market Returns (1926–2025)[32]



Q54. Did you consider another form of the CAPM in your analysis?

A54. Yes. I also consider the results of an ECAPM in estimating the cost of equity for the Company.[33] The ECAPM calculates the product of the adjusted beta coefficient and the

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[32] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook for 1926-2022 and from S&P Capital IQ Pro for 2023-2025.

[33] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market cost of equity;

β = adjusted beta coefficient of an individual security;

r_f = the risk-free rate of return; and,

r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[34]

Consistent with my CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bonds as the risk-free rate, forward-looking market risk premium estimates, and beta coefficients.

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[34] *Id.,* at 191.

Q55. What are the results of your CAPM and ECAPM analyses?

A55. The results of my CAPM and ECAPM analyses are summarized in Figure 7, as well as presented in Exhibit No.___(CMW-2), Schedule 5.

Figure 7: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.13%	11.11%	11.05%
Long-term Avg. *Value Line* Beta	11.39%	11.37%	11.32%
ECAPM:			
Current *Value Line* Beta	11.67%	11.65%	11.61%
Long-term Avg. *Value Line* Beta	11.86%	11.85%	11.81%

C. BYRP Analysis

Q56. Please describe your BYRP analysis.

A56. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q57. What is the fundamental relationship between the equity risk premium and interest rates?

A57. Both academic literature and market evidence indicates that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit No.__(CMW-2), Schedule 8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[35]

Q58. What did your BYRP analysis reveal?

A58. As shown in Figure 8, from January 1980 through April 30, 2026, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$\mathrm{RP} = \mathrm{a} + \mathrm{b}(\mathrm{T}) \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

[35] *See e.g.,* S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93*," Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also,* Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

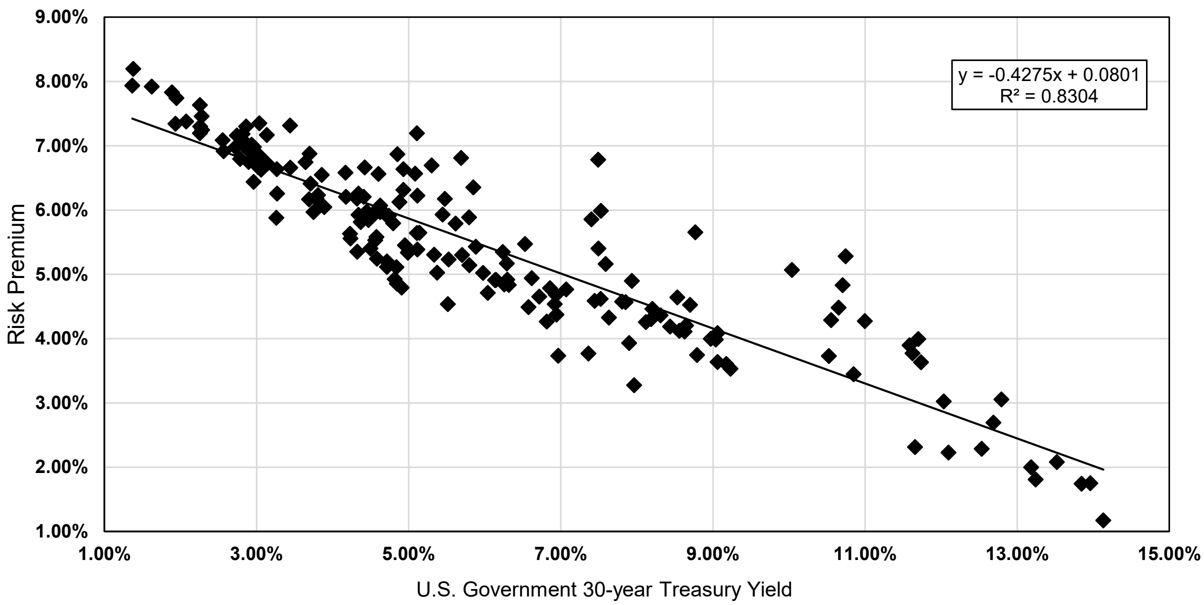
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from the vertically integrated electric utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[36] The equation's coefficients are statistically significant at the 99.00 percent level.

Figure 8: Risk Premium Regression Analysis



Q59. What are the results of your BYRP analysis?

A59. Figure 9 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit No. ___(CMW-2), Schedule 8.

[36] The data was screened to eliminate limited issue rider cases, transmission-only cases, distribution-only cases and cases that were silent with respect to the authorized ROE.

Figure 9: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.82%	10.77%	10.64%

Q60. How did the results of the BYRP inform your recommended ROE for Montana-Dakota?

A60. I consider the results of the BYRP analysis as a check on the reasonableness of the DCF, CAPM and ECAPM model results. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of vertically integrated utilities across the U.S.

VII. REGULATORY AND BUSINESS RISKS

Q61. Please explain how you use the results of the cost of equity models in estimating the Company's cost of equity?

A61. The results of the cost of equity models provide a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be considered when determining where the Company's cost of equity falls within the range of analytical results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Service Territory Risk

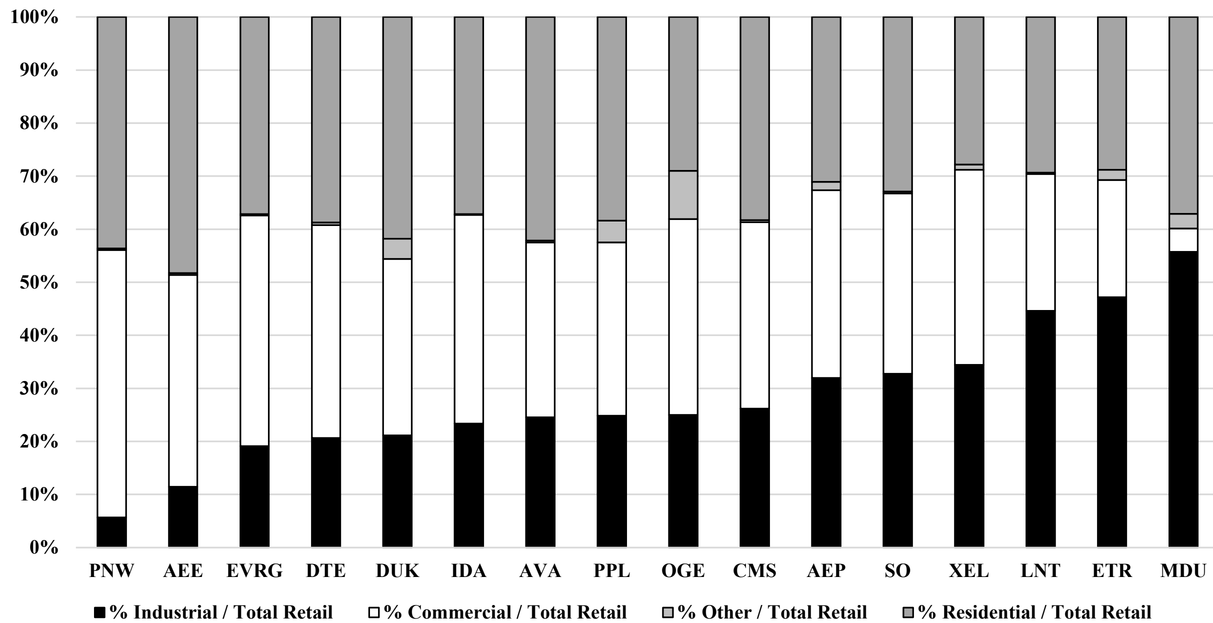
Q62. Please summarize Montana-Dakota's service territory risk.

A62. As noted above, Montana-Dakota provides electric service to approximately 94,700 customers in North Dakota.[37] The Company's service area is in Central and Western North Dakota, where a number of Montana-Dakota's large general service customers are engaged in crude oil refining, oil and natural gas production, precious metal refining and manufacturing. As I will discuss in more detail below, the oil and natural gas production industry represents a large portion of the economy in North Dakota and supports the Company's residential and commercial customers. Approximately 56 percent of Montana-Dakota's 2025 total retail kWh electric sales in North Dakota were derived from the large general customer class. As shown in Figure 10, Montana-Dakota's large general service sales volume as a percentage of total retail electric sales was higher than all of the companies in the proxy group.[38]

[37] Montana-Dakota Utilities, 2025 Annual Report to the North Dakota Public Service Commission, IV. Miscellaneous, Line No. 7.

[38] Does not include "other" or residential customers.

Figure 10: Customer Concentration – 2025 Electric Sales[39]



Q63. How does customer concentration and the Company's service territory affect business risk?

A63. An extremely high concentration of industrial and large commercial customers results in higher business risk. Since the customers are large, they can represent a significant portion of a company's sales, which could be lost if a customer goes out of business or otherwise stops taking service from the utility. As noted by Dhaliwal, Judd, Serfling and Shaikh (2016), there can be significant risks related to a single customer representing a large portion of sales:

> Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons. First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock

[39] Source: S&P Capital IQ Pro - Other sales includes: Total Public Street and Highway Lighting, Other Sales to Public Authorities, Sales to Railroad and Railways, and Interdepartmental.

> returns to the announcement that a major customer declares bankruptcy. Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt. This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).[40]

Therefore, a company that has a high degree of customer concentration will be inherently riskier than a company that derived income from a larger customer base. Furthermore, as stated in Dhaliwal, Judd, Serfling and Shaikh (2016), the increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[41]

Q64. Please describe how changes in economic conditions and the interdependent nature of Montana-Dakota's service territory can affect its business risk?

A64. While Montana-Dakota doesn't depend on any one major customer, it is important to note that one large general service customer in the oil refining industry did comprise 8.42 percent of the Company's 2025 total retail electric sales. Furthermore, the Company has a high concentration of large general service customers. Montana-Dakota's major large general service customers are engaged in industries such as crude oil refining, oil and natural gas production, precious metal refining and manufacturing. Additionally, North Dakota's state economy depends on the oil and natural gas production industry; thus the industry also supports the Company's commercial and residential customers. It is well-

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40 Dan S. Dhaliwal, J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh, "Customer Concentration Risk and the Cost of Equity Capital," *Journal of Accounting & Economics*, March 23, 2015.

41 *Id.,* at 4.

documented that the oil and natural gas production industry is very cyclical. Additionally, like other industries, the oil and natural gas production industries are also dependent on the general business cycle. As a result, the production of the customers could change based on general or industry specific economic conditions thereby impacting the customers' energy consumption.

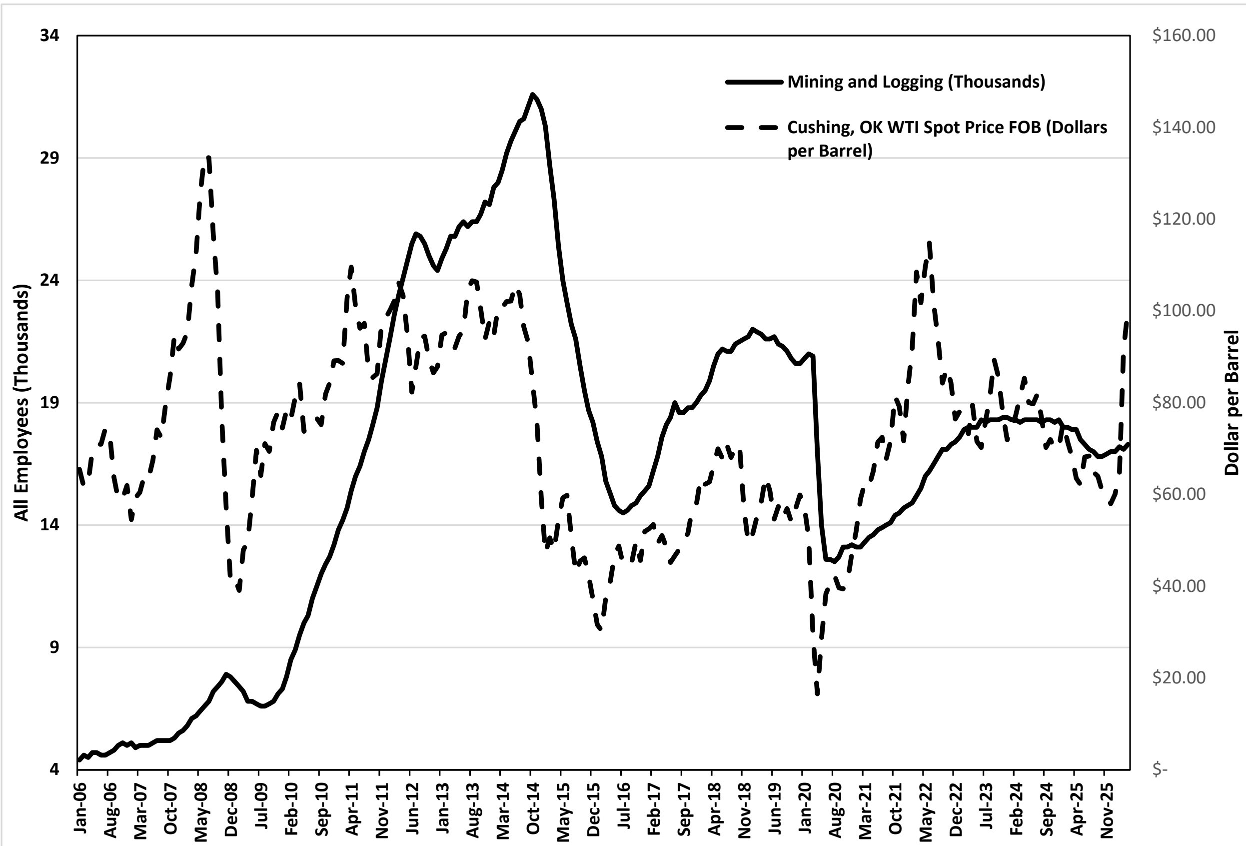
Q65. How has employment in the oil and natural gas production industry fared in recent economic conditions?

A65. Figure 11 below contains data on mining and logging employment in North Dakota from January 2006 through April 2026. I reviewed mining and logging employment because this data series considers employment in the oil and natural gas production industry. As shown in Figure 11, mining and logging employment in North Dakota has been highly dependent on the price of oil which has been very volatile since 2006. For example, the decline in the price of oil that began in 2014 and ended in 2016 resulted in a decrease in mining and logging employment in North Dakota from 31,600 in October 2014 to a low of 14,500 in July 2016 (i.e., a decline of approximately 50 percent). Similarly, since the COVID-19 pandemic, oil prices and mining and logging employment have remained correlated with mining and logging employment increasing when oil prices are increasing and vice versa. In 2025, mining and logging employment declined slightly as a result of the decline in oil prices due to the effects of global tariffs.[42] More recently in 2026, while oil prices have increased significantly as a result of the conflict in Iran, mining and logging employment has only increased slightly because uncertainty around how long oil prices

[42] Chu, Amanda. "Trump tariff talk roils US oil industry in bedrock Republican territory." *Financial Times,* April 22, 2025.

will remain elevated has currently resulted in companies increasing production of existing wells as opposed to opening new wells.[43]

Figure 11: North Dakota Mining and Logging Employment (Thous.) & West Texas Intermediate Spot Price for a Barrel of Oil[44]



Q66. Are Montana-Dakota's electric sales dependent on the oil refining and natural gas and oil production industries?

A66. Yes. As discussed above, a large portion of the Company's electric sales were to large general service customers some of which operate in the natural gas and oil production and oil refining industries. Moreover, since the economy in Western North Dakota is heavily

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43 Orledge, Jacob. "Value of North Dakota Oil Rises as Iran War Upends Markets." *North Dakota Monitor*, April 21, 2026. northdakotamonitor.com/2026/04/21/value-of-north-dakota-oil-rises-as-iran-war-upends-markets/. Accessed 9 June 2026.

44 Source: Bureau of Labor Statistics and the EIA.

reliant on the oil and natural gas production industry, Montana-Dakota's commercial and residential customers also rely on the industry for sales and employment. For example, a recent study conducted by North Dakota State University noted the oil and gas industries' contribution to the North Dakota economy in 2023:

> According to the study, North Dakota's oil and gas industry directly employed 30,100 people in 2023. When factoring in indirect and induced jobs, the industry supported 63,830 jobs statewide. Employment compensation, which includes wages, salaries, and benefits, was estimated at $5 billion.
>
> Gross business volume, which includes direct sales in the oil and natural gas sector along with the broader economic activity generated by the industry, set an all-time high of $48.8 billion — a $6.2 billion increase over 2021, accounting for more than 30% of the state's overall economic activity.[45]

In fact, when discussing the effect of global tariffs, a 2025 article in the *Financial Times* noted that North Dakota was especially sensitive to changes in oil prices:

> North Dakota — the third-largest oil-producing state — is especially vulnerable to falling crude prices and slowing production, more so than peers such as Texas and Louisiana, which have more diversified economies. A shrinking inventory of wells and an increasingly consolidated, financially restrained industry, has slowed drilling in the Bakken.[46]

Therefore, fluctuations in the price of oil as a result of the overall business cycle or external events that occur in the industry can have a significant effect on the economic conditions in Montana-Dakota's service territory in the near- and long-term. This could result in a reduction in sales to large general service customers. Additionally, if large general service customers reduce output, the effect would be compounded by a decline in local

[45] North Dakota State University News, "NDSU researcher highlights oil and gas Industry's $48.8 billion economic impact", March 11, 2025.

[46] Chu, Amanda. "Trump tariff talk roils US oil industry in bedrock Republican territory." *Financial Times,* April 22, 2025.

employment which would also reduce the electric sales for Montana-Dakota's residential and commercial customers.

Q67. What is your conclusion regarding the Company's service territory and its effect on the cost of equity for Montana-Dakota?

A67. Montana-Dakota is heavily reliant on sales to large general service customers. As noted above, approximately 56 percent of Montana-Dakota's 2025 total electric sales in North Dakota were to large general service customers. This concentration is higher than all of the proxy group companies. A high degree of customer concentration increases Montana-Dakota's risk related to customer migration and changes in economic conditions. This risk is greater in Montana-Dakota's service territory because the residential and commercial customers rely on the success of the oil and natural gas production industry for sales and employment. Increased customer and economic diversity decreases the effect that any one customer or industry can have on a company's sales. Thus, Montana-Dakota's service territory, where large general service customers represent a large portion of electric sales and commercial and residential customers rely economically on the success of the one industry segment, implies that Montana-Dakota has an above average risk profile when compared to the companies in the proxy group.

B. Flotation Cost

Q68. What are flotation costs?

A68. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q69. Why is it important to consider flotation costs in the allowed ROE?

A69. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q70. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A70. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny Montana-Dakota the opportunity to earn its required rate of return in the future.

Q71. Can you provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested?

A71. Yes. Suppose MDU issues stock with a value of $100, and an equity investor invests $100 in MDU in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q72. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A72. No. Although Montana-Dakota is a wholly-owned subsidiary of MDU, it is appropriate to consider flotation costs because wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund the utility operations and could inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q73. Is the need to consider flotation costs recognized by the academic and financial communities?

A73. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and

> prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[47]

Q74. How did you calculate the flotation costs for MDU?

A74. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU in its two most recent common equity issuances. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit No.___(CMW-2), Schedule 9, based on the flotation costs previously incurred by MDU, the impact on the proxy group's cost of equity amounts to 12 basis points (i.e., 0.12 percent).

Q75. Do your final cost of equity results include an adjustment for flotation cost recovery?

A75. No, I did not make an explicit adjustment for flotation costs to any of the quantitative results of my cost of equity models. Rather, I considered the incremental cost associated with stock issuance as part of my overall recommendations regarding the range of reasonable ROEs and ultimate recommended ROE.

C. Regulatory Risk

Q76. How does the regulatory environment affect investors' risk assessments?

A76. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on,

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[47] Shannon P. Pratt, *Cost of Capital Estimation and Applications* (2nd ed. 2002), at 220-221.

invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q77. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A77. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[48]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[49] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[50]

[48] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2.

[49] Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.

[50] *Id*.

Q78. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A78. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[51] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[52]

Q79. Have you analyzed the regulatory framework in North Dakota relative to the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A79. Yes. I have evaluated the regulatory framework in North Dakota based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk

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[51] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 8.

[52] *Id*.

assessment are shown in Exhibit No.___(CMW-2), Schedule 10 and are summarized below:

Test Year Convention: Montana-Dakota is proposing to use projected test years as of December 31, 2026 and December 31, 2027 in North Dakota which is similar to approximately 53.01 percent of the utility operating subsidiaries of the companies in the proxy group that use either fully forecasted or partially forecasted test years.

Volumetric Risk: Montana-Dakota does not have protection against volumetric risk in North Dakota, either through a revenue decoupling mechanism, formula rate plan or straight fixed-variable rate design. However, approximately 68.67 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: Montana-Dakota does have capital tracking mechanisms (*i.e.,* Renewable Resource Cost Adjustment, Generation Resource Recovery Rider, Environmental Cost Recovery Rider and Transmission Cost Adjustment) and is proposing to use a fully forecast test year which will allow the Company to recover a portion of its capital expenditures plan. Similarly, 80.72 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

Q80. What are your conclusions regarding the perceived risks related to the regulatory environment in North Dakota?

A80. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms of the Company relative to the proxy group, many of the companies in the proxy group have more timely cost recovery between rate proceedings than Montana-Dakota has in North Dakota. For this reason, I conclude that Montana-Dakota has slightly greater than average regulatory risk when compared to the proxy group.

VIII. CAPITAL STRUCTURE

Q81. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A81. Yes, it is. The equity ratio is one of the primary indicators of financial risk for a regulated utility such as Montana-Dakota. Assuming other factors equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q82. What is the Company's proposed capital structure?

A82. Montana-Dakota is proposing a projected capitalization for 2026 that is composed of 50.185 percent equity, 45.033 percent long-term debt and 4.782 percent short-term debt. The Company's proposed capitalization for 2027 is composed of 50.159 percent equity, 45.053 percent long-term debt and 4.788 percent short-term debt.

Q83. Do you conduct any analysis to determine if this requested equity ratio was reasonable?

A83. Yes. I compare the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look at the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I have calculated the average proportion of common equity, long-term debt, short-term debt and preferred equity for the most recent eight quarters for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No.___(CMW-2), Schedule 11, the common equity ratios for the operating subsidiaries of the proxy group companies range from 47.57 percent to 57.17 percent, with an average of 51.47 percent. Montana-Dakota's proposed equity ratios of 50.185 percent in 2026 and 50.159 percent in 2027 are below the average equity ratio for the utility operating subsidiaries of the proxy group and are therefore reasonable.

Q84. Are there other factors to be considered in setting the Company's capital structure?

A84. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, Moody's recently maintained its "stable" outlook for 2026 for the regulated gas and electric utilities sector based on the expectation of continued regulatory support in "most states." [53] Moody's makes clear that constructive regulatory outcomes that promote timely cost recovery is the key factor in supporting utility credit quality as Moody's has identified that utilities could be exposed to a number of credit negative factors over the next 12 to 18 months. Specifically, Moody's noted the following factors: (1) macroeconomic factors are expected to be modestly credit negative due to upward pressure on electric prices and elevated inflation; and (2) increased power demand due to "the development of new data centers, electrification of transportation and buildings, manufacturing customers and underlying population growth" will increase power prices which when coupled with inflation and elevated capital spending increases utilities' exposure to affordability concerns.[54]

S&P states that after five years of downgrades outpacing upgrades, in 2025, upgrades outpaced downgrades and the percentage of companies with a negative outlook declined which S&P noted pointed to a "more stable environment for credit quality in 2026".[55]

[53] Moody's Investors Service, Outlook, "Outlook Stable; supportive regulation to offset modestly negative macro factors," October 31, 2025.

[54] *Id.*

[55] S&P Global Ratings. Industry Credit Outlook 2026, "North American Regulated Utilities: Data center growth will support credit quality in 2026," January 14, 2026.

However, S&P expects the industry to have increased cash flow deficits as a result of significant capital spending, which must be funded with both debt and equity to maintain credit quality.[56] Therefore, S&P notes that the utility industry will need ongoing access to capital markets to fund the significant capital expenditures. S&P also notes that credit quality will depend on the ability of utilities to manage regulatory risk and achieve fair rate case orders. Finally, while S&P's base case results in a stable outlook for the utility sector, S&P states that about 40 percent of the industry has "minimal financial cushion" from the downgrade threshold and therefore would have limited ability to absorb any unexpected events outside of what is assumed in S&P's base case.[57]

Fitch maintains a "neutral" outlook for the utility industry in 2026 noting that the stable outlook was supported by growth in sales related to data centers and a "generally benign" regulatory environment for utilities.[58] However, while Fitch views load growth as a "positive development" because the growth is related to data centers, it raises longer-term uncertainty related to "rate design, customer concentration, and technology risks".[59] Further, Fitch states that capital expenditures for the industry will continue to "set records" in order to meet the growing demand and to enhance reliability and modernize. The record capital expenditures will require a balanced regulatory environment to facilitate cost recovery in a credit supportive manner.[60]

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[56] *Id.*
[57] *Id.*
[58] Fitch Ratings, "North American Utilities & Power Outlook 2026," December 9, 2025, at 1
[59] *Id.*
[60] *Id.*

The continued concerns of the credit ratings agencies over increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the Company in the context of this proceeding.

Q85. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A85. Yes. Because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Consequently, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

Q86. What is your conclusion regarding an appropriate equity ratio for Montana-Dakota?

A86. Considering the actual capital structures of the utility operating subsidiaries of the proxy group, I believe that Montana-Dakota's proposed common equity ratios of 50.185 percent for 2026 and 50.159 percent for 2027 are reasonable. The projected equity ratios are well within the range of equity ratios established by the capital structures of the utility operating subsidiaries of the proxy companies.

IX. CONCLUSION AND RECOMMENDATION

Q87. What is your conclusion regarding a fair ROE for Montana-Dakota?

A87. Figure 12 summarizes the results of my cost of equity analyses. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of

Montana-Dakota compared to the proxy group, and current and prospective conditions in capital markets, it is my view that an ROE of 10.80 percent is reasonable.

Figure 12: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.10%	10.46%	11.57%
90-Day Avg. Stock Price	9.22%	10.59%	11.70%
180-Day Avg. Stock Price	9.32%	10.68%	11.80%
Average	9.21%	10.58%	11.69%
Median Results:			
30-Day Avg. Stock Price	9.46%	10.48%	11.32%
90-Day Avg. Stock Price	9.61%	10.58%	11.42%
180-Day Avg. Stock Price	9.77%	10.71%	11.44%
Average	9.61%	10.59%	11.39%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.13%	11.11%	11.05%
Long-term Avg. *Value Line* Beta	11.39%	11.37%	11.32%
ECAPM:			
Current *Value Line* Beta	11.67%	11.65%	11.61%
Long-term Avg. *Value Line* Beta	11.86%	11.85%	11.81%
Bond Yield Risk Premium	10.82%	10.77%	10.64%

Q88. What is your conclusion regarding the Company's proposed capital structure?

A88. The Company's projected capital structures are reasonable when compared to the capital structures of the companies in the proxy group.

Q89. Does this conclude your direct testimony?

A89. Yes.

Christopher Wall

PRINCIPAL

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With 15 years of experience as a financial and economic consultant in the energy industry, Mr. Wall specializes in regulatory economics for the electric, natural gas, and water utility sectors.

Mr. Wall has expertise in matters related to rate of return, cost of equity, capital structure, cost of service, and rate design. He has prepared expert testimony related to return on equity and capital structure in over 100 regulatory proceedings for electric, natural gas, and water utility clients across the US.

He has applied his economics, financial modeling, advanced statistics, and econometrics competencies to prepare rate design, rate consolidation, marginal cost, cost of service, valuation, and demand forecast studies for electric and natural gas utilities. These studies have been submitted in utility regulatory proceedings throughout North America.

Mr. Wall has provided expert testimony before regulatory commissions in Arkansas, Massachusetts, New Hampshire, New York, Pennsylvania and South Dakota on issues that include cost of capital, natural gas demand forecasting, and statistical concepts for return on equity and cost of service.

Prior to joining Brattle, Mr. Wall was an Assistant Vice President at an economic consulting firm.

AREAS OF EXPERTISE

- Electricity Litigation & Regulatory Disputes
- M&A Litigation
- Oil & Gas
- Regulatory Economics, Finance & Rates
- Regulatory Investigations and Enforcement

EDUCATION

- **Northeastern University**
  MA in Economics
- **Saint Peter's College**
  BA in Economics and Mathematics (summa cum laude)

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal (2024-Present)
  Senior Associate (2022-2023)
- **Concentric Energy Advisors, Inc. (2010–2021)**
  Assistant Vice President (2021)
  Senior Project Manager (2019–2020)
  Project Manager (2017–2018)
  Senior Consultant (2015–2016)
  Consultant (2013–2014)
  Assistant Consultant (2011–2012)
  Associate (2010)

SELECTED CONSULTING EXPERIENCE

COST OF CAPITAL

- Provided expert testimony on the cost of capital for electric, natural gas and water utilities.
- Prepared expert testimony and exhibits for return on equity, capital structure, and cost of debt analysis for numerous electric, gas, and water utility clients across the US. This included preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting and reviewing post-hearing briefs.

DEMAND FORECASTING & SUPPLY PLANNING

- Filed expert testimony regarding the development of the natural gas demand forecast for a Northeast gas utility.

- Contributed to and worked on demand forecasting projects for multiple Northeast gas utilities:
  - Assisted in the development of natural gas price and effective degree day forecasts.
  - Developed natural gas demand forecasts by customer class using SPSS.
    - Developed models for number of customers and use per customer.
    - Performed checks for model stability, heteroscedasticity, and autocorrelation by performing the Chow, Breusch-Pagan, and Autocorrelation Function/Partial Autocorrelation Function tests.
  - Contributed in the development of the forecasting and supply planning report and supported data requests.

RATEMAKING

- Evaluated rate design restructuring and its impacts on customer bills for Northeast gas and electric utilities.
- Developed marginal cost studies and prepared testimony for Northeast electric and gas utilities.
- Designed rates and prepared testimony for a Northeast electric and gas utility.
- Prepared a cost of service study and designed rates for a Mid-Atlantic municipal gas utility.
- Prepared cost of service studies and designed rates for Midwest electric and gas utilities.
- Evaluated the impact of different rate alternatives and solar generation compensation approaches on solar customers in each rate class for a Midwest municipal electric utility.
- Contributed to the development of a benchmarking study to compare a Canadian natural gas utility’s performance with its peers.
- Assisted in the development of a Total Factor Productivity Analysis for a Canadian natural gas utility as part of an Incentive Ratemaking report filed with the Ontario Energy Board.

VALUATION

- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared expert testimony regarding the fair value of the distribution system assets of a Midwest natural gas utility and the fair value of the transmission and distribution system assets of a different Midwest electric utility.

EXPERT TESTIMONY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	04/14	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Statistical Concepts for Return on Equity and Class Cost of Service
Massachusetts Department of Public Utilities				
Berkshire Gas Company	11/25	Berkshire Gas Company	D.P.U. 25-170	Cost of Capital / Capital Structure
Berkshire Gas Company	06/22	Berkshire Gas Company	D.P.U. 22-20	Cost of Capital / Capital Structure
Berkshire Gas Company	11/20	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	11/18	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	07/16	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	08/14	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas	07/23	EnergyNorth Natural Gas	Docket No. DG 23-067	Cost of Capital / Capital Structure
Granite State Electric	05/23	Granite State Electric	Docket No. DE 23-039	Cost of Capital / Capital Structure
New York State Department of Public Service				
Corning Natural Gas Corporation	07/24	Corning Natural Gas Corporation	Case No. 24-G-0447	Cost of Capital / Capital Structure
Liberty Utilities (New York Water)	05/23	Liberty Utilities (New York Water)	Case No. 23-W-0235	Cost of Capital / Capital Structure
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Cost of Capital / Capital Structure
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Cost of Capital / Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Pennsylvania Public Utility Commission				
Pike County Light and Power Company	05/25	Pike County Light and Power Company	Docket No. R-2024-3052359	Cost of Capital / Capital Structure
Pike County Light and Power Company	05/25	Pike County Light and Power Company	Docket No. R-2024-3052357	Cost of Capital / Capital Structure
South Dakota Public Utilities Commission				
Montana-Dakota Utilities Co.	08/23	Montana-Dakota Utilities Co.	Docket No. NG23-014	Cost of Capital / Capital Structure

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS AS OF APRIL 30, 2026

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.10%	10.46%	11.57%
90-Day Avg. Stock Price	9.22%	10.59%	11.70%
180-Day Avg. Stock Price	9.32%	10.68%	11.80%
Average	9.21%	10.58%	11.69%
Median Results:			
30-Day Avg. Stock Price	9.46%	10.48%	11.32%
90-Day Avg. Stock Price	9.61%	10.58%	11.42%
180-Day Avg. Stock Price	9.77%	10.71%	11.44%
Average	9.61%	10.59%	11.39%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.13%	11.11%	11.05%
Long-term Avg. *Value Line* Beta	11.39%	11.37%	11.32%
ECAPM:			
Current *Value Line* Beta	11.67%	11.65%	11.61%
Long-term Avg. *Value Line* Beta	11.86%	11.85%	11.81%
Bond Yield Risk Premium	10.82%	10.77%	10.64%

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Positive Growth Rates from at least two sources (S&P Capital IQ, Value Line, and Zacks)	[4] Generation Assets Included in Rate Base	[5] Net Generation as a % of Total Sales > 40%	[6] Regulated Elec. Operating Income / Total Operating Income > 60%	[7] Announced Merger
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	Yes	76.11%	87.45%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	71.06%	84.42%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	53.12%	95.39%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	60.63%	74.40%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	50.66%	63.56%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	84.78%	64.14%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	81.20%	89.73%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	72.59%	97.76%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	59.95%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	64.28%	99.99%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	41.91%	97.73%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	69.56%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	41.60%	94.19%	No
Southern Company	SO	Yes	A-	Yes	Yes	76.82%	78.69%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	58.19%	85.43%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] S&P Capital IQ Pro
[5] S&P Capital IQ Pro
[6] Form 10-K's for 2025, 2024, and 2023
[7] S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$71.31	3.00%	3.11%	6.00%	7.20%	8.04%	7.08%	9.09%	10.19%	11.16%
Ameren Corporation	AEE	$3.00	$110.76	2.71%	2.82%	6.50%	9.30%	8.02%	7.94%	9.30%	10.76%	12.13%
American Electric Power Company, Inc.	AEP	$3.80	$132.66	2.86%	2.97%	6.50%	6.70%	8.55%	7.25%	9.46%	10.22%	11.54%
Avista Corporation	AVA	$1.97	$40.72	4.84%	4.99%	5.00%	7.10%	6.23%	6.11%	9.96%	11.10%	12.11%
CMS Energy Corporation	CMS	$2.28	$77.02	2.96%	3.07%	8.00%	7.10%	7.54%	7.55%	10.17%	10.62%	11.08%
DTE Energy Company	DTE	$4.66	$146.55	3.18%	3.28%	5.50%	5.90%	7.51%	6.30%	8.77%	9.58%	10.81%
Duke Energy Corporation	DUK	$4.26	$129.14	3.30%	3.40%	6.00%	n/a	6.58%	6.29%	9.40%	9.69%	9.99%
Entergy Corporation	ETR	$2.56	$111.10	2.30%	2.41%	3.00%	11.50%	11.91%	8.80%	5.34%	11.21%	14.36%
Evergy, Inc.	EVRG	$2.78	$81.62	3.41%	3.55%	6.50%	9.10%	8.93%	8.18%	10.02%	11.72%	12.66%
IDACORP, Inc.	IDA	$3.52	$143.93	2.45%	2.53%	5.00%	7.80%	8.28%	7.03%	7.51%	9.56%	10.83%
OGE Energy Corporation	OGE	$1.70	$47.76	3.56%	3.65%	3.00%	5.60%	6.57%	5.06%	6.61%	8.71%	10.25%
Pinnacle West Capital Corporation	PNW	$3.64	$101.60	3.58%	3.70%	6.00%	5.80%	8.12%	6.64%	9.49%	10.34%	11.85%
PPL Corporation	PPL	$1.14	$38.42	2.97%	3.08%	7.50%	7.50%	7.91%	7.64%	10.58%	10.72%	10.99%
Southern Company	SO	$2.96	$95.18	3.11%	3.22%	6.50%	7.20%	8.08%	7.26%	9.71%	10.48%	11.32%
Xcel Energy Inc.	XEL	$2.37	$79.65	2.98%	3.11%	8.00%	9.40%	9.36%	8.92%	11.09%	12.03%	12.52%
Mean				3.15%	3.26%	5.93%	7.66%	8.11%	7.20%	9.10%	10.46%	11.57%
Median				3.00%	3.11%	6.00%	7.20%	8.04%	7.25%	9.46%	10.48%	11.32%

Notes:
[1] Bloomberg Professional as of April 30, 2026
[2] Bloomberg Professional 30-day average as of April 30, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$68.80	3.11%	3.22%	6.00%	7.20%	8.04%	7.08%	9.20%	10.30%	11.28%
Ameren Corporation	AEE	$3.00	$107.00	2.80%	2.91%	6.50%	9.30%	8.02%	7.94%	9.39%	10.86%	12.23%
American Electric Power Company, Inc.	AEP	$3.80	$126.03	3.02%	3.12%	6.50%	6.70%	8.55%	7.25%	9.61%	10.37%	11.69%
Avista Corporation	AVA	$1.97	$40.17	4.90%	5.05%	5.00%	7.10%	6.23%	6.11%	10.03%	11.17%	12.18%
CMS Energy Corporation	CMS	$2.28	$74.37	3.07%	3.18%	8.00%	7.10%	7.54%	7.55%	10.27%	10.73%	11.19%
DTE Energy Company	DTE	$4.66	$140.49	3.32%	3.42%	5.50%	5.90%	7.51%	6.30%	8.91%	9.72%	10.95%
Duke Energy Corporation	DUK	$4.26	$124.86	3.41%	3.52%	6.00%	n/a	6.58%	6.29%	9.51%	9.81%	10.10%
Entergy Corporation	ETR	$2.56	$102.34	2.50%	2.61%	3.00%	11.50%	11.91%	8.80%	5.54%	11.42%	14.56%
Evergy, Inc.	EVRG	$2.78	$78.81	3.53%	3.67%	6.50%	9.10%	8.93%	8.18%	10.14%	11.85%	12.79%
IDACORP, Inc.	IDA	$3.52	$138.00	2.55%	2.64%	5.00%	7.80%	8.28%	7.03%	7.61%	9.67%	10.94%
OGE Energy Corporation	OGE	$1.70	$45.71	3.72%	3.81%	3.00%	5.60%	6.57%	5.06%	6.78%	8.87%	10.42%
Pinnacle West Capital Corporation	PNW	$3.64	$96.93	3.76%	3.88%	6.00%	5.80%	8.12%	6.64%	9.66%	10.52%	12.03%
PPL Corporation	PPL	$1.14	$37.01	3.08%	3.20%	7.50%	7.50%	7.91%	7.64%	10.70%	10.83%	11.11%
Southern Company	SO	$2.96	$92.33	3.21%	3.32%	6.50%	7.20%	8.08%	7.26%	9.81%	10.58%	11.42%
Xcel Energy Inc.	XEL	$2.37	$78.08	3.04%	3.17%	8.00%	9.40%	9.36%	8.92%	11.16%	12.09%	12.58%
Mean				3.27%	3.38%	5.93%	7.66%	8.11%	7.20%	9.22%	10.59%	11.70%
Median				3.11%	3.22%	6.00%	7.20%	8.04%	7.25%	9.61%	10.58%	11.42%

Notes:
[1] Bloomberg Professional as of April 30, 2026
[2] Bloomberg Professional 90-day average as of April 30, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$66.95	3.20%	3.31%	6.00%	7.20%	8.04%	7.08%	9.29%	10.39%	11.36%
Ameren Corporation	AEE	$3.00	$103.79	2.89%	3.01%	6.50%	9.30%	8.02%	7.94%	9.48%	10.95%	12.32%
American Electric Power Company, Inc.	AEP	$3.80	$119.92	3.17%	3.28%	6.50%	6.70%	8.55%	7.25%	9.77%	10.53%	11.85%
Avista Corporation	AVA	$1.97	$38.80	5.08%	5.23%	5.00%	7.10%	6.23%	6.11%	10.20%	11.34%	12.36%
CMS Energy Corporation	CMS	$2.28	$73.03	3.12%	3.24%	8.00%	7.10%	7.54%	7.55%	10.33%	10.79%	11.25%
DTE Energy Company	DTE	$4.66	$137.54	3.39%	3.49%	5.50%	5.90%	7.51%	6.30%	8.98%	9.80%	11.02%
Duke Energy Corporation	DUK	$4.26	$122.85	3.47%	3.58%	6.00%	n/a	6.58%	6.29%	9.57%	9.87%	10.16%
Entergy Corporation	ETR	$2.56	$96.88	2.64%	2.76%	3.00%	11.50%	11.91%	8.80%	5.68%	11.56%	14.71%
Evergy, Inc.	EVRG	$2.78	$76.20	3.65%	3.80%	6.50%	9.10%	8.93%	8.18%	10.27%	11.98%	12.91%
IDACORP, Inc.	IDA	$3.52	$132.76	2.65%	2.74%	5.00%	7.80%	8.28%	7.03%	7.72%	9.77%	11.05%
OGE Energy Corporation	OGE	$1.70	$44.76	3.80%	3.89%	3.00%	5.60%	6.57%	5.06%	6.86%	8.95%	10.50%
Pinnacle West Capital Corporation	PNW	$3.64	$92.44	3.94%	4.07%	6.00%	5.80%	8.12%	6.64%	9.85%	10.71%	12.22%
PPL Corporation	PPL	$1.14	$36.34	3.14%	3.26%	7.50%	7.50%	7.91%	7.64%	10.75%	10.89%	11.17%
Southern Company	SO	$2.96	$91.67	3.23%	3.35%	6.50%	7.20%	8.08%	7.26%	9.83%	10.61%	11.44%
Xcel Energy Inc.	XEL	$2.37	$77.04	3.08%	3.21%	8.00%	9.40%	9.36%	8.92%	11.20%	12.14%	12.62%
Mean				3.36%	3.48%	5.93%	7.66%	8.11%	7.20%	9.32%	10.68%	11.80%
Median				3.20%	3.31%	6.00%	7.20%	8.04%	7.25%	9.77%	10.71%	11.44%

Notes:
[1] Bloomberg Professional as of April 30, 2026
[2] Bloomberg Professional 180-day average as of April 30, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
Ameren Corporation	AEE	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
American Electric Power Company, Inc.	AEP	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
Avista Corporation	AVA	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
CMS Energy Corporation	CMS	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
DTE Energy Company	DTE	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
Duke Energy Corporation	DUK	4.91%	0.65	13.28%	8.36%	10.35%	11.08%
Entergy Corporation	ETR	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
Evergy, Inc.	EVRG	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
IDACORP, Inc.	IDA	4.91%	0.65	13.28%	8.36%	10.35%	11.08%
OGE Energy Corporation	OGE	4.91%	0.85	13.28%	8.36%	12.02%	12.34%
Pinnacle West Capital Corporation	PNW	4.91%	0.75	13.28%	8.36%	11.19%	11.71%
PPL Corporation	PPL	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
Southern Company	SO	4.91%	0.65	13.28%	8.36%	10.35%	11.08%
Xcel Energy Inc.	XEL	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
Mean						11.13%	11.67%
Median						11.19%	11.71%

Notes:
[1] Bloomberg Professional 30-day average as of April 30, 2026
[2] Value Line
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2026 - Q3 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
Ameren Corporation	AEE	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
American Electric Power Company, Inc.	AEP	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
Avista Corporation	AVA	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
CMS Energy Corporation	CMS	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
DTE Energy Company	DTE	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
Duke Energy Corporation	DUK	4.82%	0.65	13.28%	8.46%	10.32%	11.06%
Entergy Corporation	ETR	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
Evergy, Inc.	EVRG	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
IDACORP, Inc.	IDA	4.82%	0.65	13.28%	8.46%	10.32%	11.06%
OGE Energy Corporation	OGE	4.82%	0.85	13.28%	8.46%	12.01%	12.33%
Pinnacle West Capital Corporation	PNW	4.82%	0.75	13.28%	8.46%	11.16%	11.69%
PPL Corporation	PPL	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
Southern Company	SO	4.82%	0.65	13.28%	8.46%	10.32%	11.06%
Xcel Energy Inc.	XEL	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
Mean						11.11%	11.65%
Median						11.16%	11.69%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 45, No. 5, May 1, 2026, at 2
[2] Value Line
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
Ameren Corporation	AEE	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
American Electric Power Company, Inc.	AEP	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
Avista Corporation	AVA	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
CMS Energy Corporation	CMS	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
DTE Energy Company	DTE	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
Duke Energy Corporation	DUK	4.60%	0.65	13.28%	8.68%	10.24%	11.00%
Entergy Corporation	ETR	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
Evergy, Inc.	EVRG	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
IDACORP, Inc.	IDA	4.60%	0.65	13.28%	8.68%	10.24%	11.00%
OGE Energy Corporation	OGE	4.60%	0.85	13.28%	8.68%	11.98%	12.30%
Pinnacle West Capital Corporation	PNW	4.60%	0.75	13.28%	8.68%	11.11%	11.65%
PPL Corporation	PPL	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
Southern Company	SO	4.60%	0.65	13.28%	8.68%	10.24%	11.00%
Xcel Energy Inc.	XEL	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
Mean						11.05%	11.61%
Median						11.11%	11.65%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14
[2] Value Line
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.91%	0.78	13.28%	8.36%	11.41%	11.88%
Ameren Corporation	AEE	4.91%	0.75	13.28%	8.36%	11.22%	11.73%
American Electric Power Company, Inc.	AEP	4.91%	0.70	13.28%	8.36%	10.74%	11.37%
Avista Corporation	AVA	4.91%	0.80	13.28%	8.36%	11.60%	12.02%
CMS Energy Corporation	CMS	4.91%	0.72	13.28%	8.36%	10.90%	11.49%
DTE Energy Company	DTE	4.91%	0.79	13.28%	8.36%	11.54%	11.97%
Duke Energy Corporation	DUK	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
Entergy Corporation	ETR	4.91%	0.78	13.28%	8.36%	11.44%	11.90%
Evergy, Inc.	EVRG	4.91%	0.91	13.28%	8.36%	12.51%	12.70%
IDACORP, Inc.	IDA	4.91%	0.74	13.28%	8.36%	11.12%	11.66%
OGE Energy Corporation	OGE	4.91%	0.95	13.28%	8.36%	12.83%	12.94%
Pinnacle West Capital Corporation	PNW	4.91%	0.77	13.28%	8.36%	11.35%	11.83%
PPL Corporation	PPL	4.91%	0.85	13.28%	8.36%	12.05%	12.36%
Southern Company	SO	4.91%	0.70	13.28%	8.36%	10.77%	11.40%
Xcel Energy Inc.	XEL	4.91%	0.69	13.28%	8.36%	10.67%	11.32%
Mean						11.39%	11.86%
Median						11.35%	11.83%

Notes:
[1] Bloomberg Professional 30-day average as of April 30, 2026
[2] Exhibit No. ___(CMW-2), Schedule 6
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2026 - Q3 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.82%	0.78	13.28%	8.46%	11.39%	11.86%
Ameren Corporation	AEE	4.82%	0.75	13.28%	8.46%	11.20%	11.72%
American Electric Power Company, Inc.	AEP	4.82%	0.70	13.28%	8.46%	10.71%	11.35%
Avista Corporation	AVA	4.82%	0.80	13.28%	8.46%	11.59%	12.01%
CMS Energy Corporation	CMS	4.82%	0.72	13.28%	8.46%	10.87%	11.47%
DTE Energy Company	DTE	4.82%	0.79	13.28%	8.46%	11.52%	11.96%
Duke Energy Corporation	DUK	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
Entergy Corporation	ETR	4.82%	0.78	13.28%	8.46%	11.42%	11.89%
Evergy, Inc.	EVRG	4.82%	0.91	13.28%	8.46%	12.50%	12.70%
IDACORP, Inc.	IDA	4.82%	0.74	13.28%	8.46%	11.10%	11.64%
OGE Energy Corporation	OGE	4.82%	0.95	13.28%	8.46%	12.82%	12.94%
Pinnacle West Capital Corporation	PNW	4.82%	0.77	13.28%	8.46%	11.33%	11.81%
PPL Corporation	PPL	4.82%	0.85	13.28%	8.46%	12.04%	12.35%
Southern Company	SO	4.82%	0.70	13.28%	8.46%	10.74%	11.37%
Xcel Energy Inc.	XEL	4.82%	0.69	13.28%	8.46%	10.64%	11.30%
Mean						11.37%	11.85%
Median						11.33%	11.81%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 45, No. 5, May 1, 2026, at 2
[2] Exhibit No. ___(CMW-2), Schedule 6
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.60%	0.78	13.28%	8.68%	11.34%	11.83%
Ameren Corporation	AEE	4.60%	0.75	13.28%	8.68%	11.14%	11.67%
American Electric Power Company, Inc.	AEP	4.60%	0.70	13.28%	8.68%	10.64%	11.30%
Avista Corporation	AVA	4.60%	0.80	13.28%	8.68%	11.54%	11.98%
CMS Energy Corporation	CMS	4.60%	0.72	13.28%	8.68%	10.81%	11.42%
DTE Energy Company	DTE	4.60%	0.79	13.28%	8.68%	11.47%	11.93%
Duke Energy Corporation	DUK	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
Entergy Corporation	ETR	4.60%	0.78	13.28%	8.68%	11.37%	11.85%
Evergy, Inc.	EVRG	4.60%	0.91	13.28%	8.68%	12.48%	12.68%
IDACORP, Inc.	IDA	4.60%	0.74	13.28%	8.68%	11.04%	11.60%
OGE Energy Corporation	OGE	4.60%	0.95	13.28%	8.68%	12.81%	12.93%
Pinnacle West Capital Corporation	PNW	4.60%	0.77	13.28%	8.68%	11.27%	11.78%
PPL Corporation	PPL	4.60%	0.85	13.28%	8.68%	12.01%	12.33%
Southern Company	SO	4.60%	0.70	13.28%	8.68%	10.67%	11.32%
Xcel Energy Inc.	XEL	4.60%	0.69	13.28%	8.68%	10.57%	11.25%
Mean						11.32%	11.81%
Median						11.27%	11.78%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14
[2] Exhibit No. ___(CMW-2), Schedule 6
[3] Exhibit No. ___(CMW-2), Schedule 7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.80	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75	0.75
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.70	0.80
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.85	0.85	0.70	0.72
DTE Energy Company	DTE	0.80	0.75	0.75	0.65	0.65	0.55	0.55	0.95	0.95	0.95	0.95	1.00	0.80	0.79
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.90	0.90	0.65	0.70
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.75	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.75	0.91
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.65	0.74
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.85	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.75	0.77
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.80	0.85
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.65	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.70	0.69
Mean		0.72	0.71	0.74	0.68	0.69	0.59	0.57	0.91	0.90	0.88	0.92	0.94	0.73	0.77

Notes:
[1] Value Line, dated December 26, 2013
[2] Value Line, dated December 31, 2014
[3] Value Line, dated December 30, 2015
[4] Value Line, dated December 29, 2016
[5] Value Line, dated December 28, 2017
[6] Value Line, dated December 27, 2018
[7] Value Line, dated December 26, 2019
[8] Value Line, dated December 30, 2020
[9] Value Line, dated December 29, 2021
[10] Value Line, dated December 30, 2022
[11] Value Line, dated December 29, 2023
[12] Value Line, dated December 27, 2024
[13] Value Line, dated December 26, 2025
[14] Average ([1] - [13])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.31%
[2] Estimate of the S&P 500 Growth Rate	11.89%
[3] S&P 500 Estimated Required Market Return	13.28%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg/Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Agilent Technologies Inc	A	282.60232	115.55	32,654.70	0.07%	0.88%	0.00%	7.74%	0.01%
Apple Inc	AAPL	14681.14	271.35	3,983,727.34	7.98%	0.40%	0.03%	11.91%	0.95%
AbbVie Inc	ABBV	1768.76238	211.32	373,774.87	0.75%	3.27%	0.02%	16.43%	0.12%
Airbnb Inc	ABNB	418.8978	140.36	58,796.50	0.12%			14.56%	0.02%
Abbott Laboratories	ABT	1741.81243	90.79	158,139.15	0.32%	2.78%	0.01%	8.17%	0.03%
Arch Capital Group Ltd	ACGL	352.9	94.46	33,334.93	0.07%			4.23%	0.00%
Accenture PLC	ACN	615.30676	178.71	109,961.47	0.22%	3.65%	0.01%	5.50%	0.01%
Adobe Inc	ADBE	404.2	246.1	99,473.62	0.20%			14.73%	0.03%
Analog Devices Inc	ADI	488.20416	402.26	196,385.01	0.39%	1.09%	0.00%	17.17%	0.07%
Archer-Daniels-Midland Co	ADM	481.87768	74.54	35,919.16	0.07%	2.79%	0.00%	12.96%	0.01%
Automatic Data Processing Inc	ADP	399.73428	211.94	84,719.68	0.17%	3.21%	0.01%	6.50%	0.01%
Autodesk Inc	ADSK	211.32532	237	50,084.10	0.10%			18.57%	0.02%
Ameren Corp	AEE	276.65322	113.65	31,441.64	0.06%	2.64%	0.00%	7.89%	0.00%
American Electric Power Co Inc	AEP	543.56348	137.11	74,527.99	0.15%	2.77%	0.00%	7.03%	0.01%
AES Corp/The	AES	713.07162	14.2741	10,178.46		4.93%		30.00%	
Aflac Inc	AFL	515.18367	113.67	58,560.93	0.12%	2.15%	0.00%	7.53%	0.01%
American International Group Inc	AIG	534.86677	74.8	40,008.03	0.08%	2.67%	0.00%	12.46%	0.01%
Assurant Inc	AIZ	49.70492	236.27	11,743.78	0.02%	1.49%	0.00%	9.50%	0.00%
Arthur J Gallagher & Co	AJG	256.88806	206.4	53,021.70	0.11%	1.36%	0.00%	15.50%	0.02%
Akamai Technologies Inc	AKAM	145.01397	102.98	14,933.54	0.03%			8.00%	0.00%
Albemarle Corp	ALB	117.65057	196.7	23,141.87		0.82%		90.56%	
Align Technology Inc	ALGN	71.61728	176.01	12,605.36	0.03%			11.15%	0.00%
Allstate Corp/The	ALL	257.42093	217.26	55,927.27	0.11%	1.99%	0.00%	9.77%	0.01%
Allegion plc	ALLE	85.93586	137.48	11,814.46	0.02%	1.60%	0.00%	6.01%	0.00%
Applied Materials Inc	AMAT	793.60987	394.49	313,071.16	0.63%	0.54%	0.00%	14.45%	0.09%
Amcor PLC	AMCR	462.04569	38.04	17,576.22	0.04%	6.83%	0.00%	8.32%	0.00%
Advanced Micro Devices Inc	AMD	1630.33878	354.49	577,938.79				36.53%	
AMETEK Inc	AME	229.203	235.5	53,977.31	0.11%	0.58%	0.00%	8.79%	0.01%
Amgen Inc	AMGN	539.6855	346.25	186,866.10	0.37%	2.91%	0.01%	4.54%	0.02%
Ameriprise Financial Inc	AMP	90.1	474.79	42,778.58	0.09%	1.43%	0.00%	11.56%	0.01%
American Tower Corp	AMT	465.89307	182.71	85,123.32	0.17%	3.92%	0.01%	3.13%	0.01%
Amazon.com Inc	AMZN	10757.10944	265.06	2,851,279.43	5.71%			17.82%	1.02%
Arista Networks Inc	ANET	1259.16944	172.71	217,471.15	0.44%			15.47%	0.07%
Aon PLC	AON	213.57356	310.83	66,385.07	0.13%	1.06%	0.00%	8.70%	0.01%
A O Smith Corp	AOS	112.37665	61.84	6,949.37	0.01%	2.33%	0.00%	7.50%	0.00%
APA Corp	APA	353.40041	40.73	14,394.00		2.46%		-0.81%	
Air Products and Chemicals Inc	APD	222.68069	300.05	66,815.34	0.13%	2.41%	0.00%	6.00%	0.01%
Amphenol Corp	APH	1229.43071	147.27	181,058.26		0.68%		23.76%	
Apollo Global Management Inc	APO	576.51906	128.72	74,209.53	0.15%	1.58%	0.00%	12.72%	0.02%
AppLovin Corp	APP	306.08692	446.35	136,621.90				38.83%	
Aptiv PLC	APTV	213.14133	60.26	12,843.90	0.03%			11.79%	0.00%
Alexandria Real Estate Equities Inc	ARE	174.26948	40.51	7,059.66		7.11%		-5.91%	
Ares Management Corp	ARES	222.02364	117.4	26,065.58		4.60%		24.65%	
Atmos Energy Corp	ATO	165.43895	189.98	31,430.09	0.06%	2.11%	0.00%	8.33%	0.01%
AvalonBay Communities Inc	AVB	139.25898	183	25,484.39	0.05%	3.89%	0.00%	4.55%	0.00%
Broadcom Inc	AVGO	4734.66818	417.43	1,976,392.54		0.62%		37.46%	
Avery Dennison Corp	AVY	76.91703	163.93	12,609.01	0.03%	2.44%	0.00%	4.88%	0.00%
American Water Works Co Inc	AWK	195.28052	128.42	25,077.92	0.05%	2.79%	0.00%	7.22%	0.00%
Axon Enterprise Inc	AXON	80.5722	401.76	32,370.69				32.37%	
American Express Co	AXP	682.32644	323.05	220,425.56	0.44%	1.18%	0.01%	13.11%	0.06%
AutoZone Inc	AZO	16.47682	3704.03	61,030.64	0.12%			9.86%	0.01%
Boeing Co/The	BA	788.30233	229.03	180,544.88				128.76%	
Bank of America Corp	BAC	7145.70918	53.46	382,009.61	0.76%	2.10%	0.02%	9.00%	0.07%
Ball Corp	BALL	266.15306	61.08	16,256.63	0.03%	1.31%	0.00%	12.13%	0.00%
Baxter International Inc	BAX	516.46901	17.58	9,079.53		0.23%		-1.59%	
Best Buy Co Inc	BBY	209.11258	60.49	12,649.22	0.03%	6.35%	0.00%	3.48%	0.00%
Becton Dickinson & Co	BDX	284.74181	149.04	42,437.92	0.08%	2.82%	0.00%	4.31%	0.00%
Franklin Resources Inc	BEN	519.63716	29.97	15,573.53	0.03%	4.40%	0.00%	9.18%	0.00%
Brown-Forman Corp	BF/B	290.26239	25.77	7,480.06	0.01%	3.59%	0.00%	1.81%	0.00%
Bunge Global SA	BG	194.01812	127.07	24,653.88	0.05%	2.27%	0.00%	3.00%	0.00%
Biogen Inc	BIIB	147.63712	189.28	27,944.75	0.06%			2.74%	0.00%
Bank of New York Mellon Corp/The	BK	686.379	134.37	92,228.75	0.18%	1.58%	0.00%	14.30%	0.03%
Booking Holdings Inc	BKNG	774.87844	168.36	130,458.53	0.26%	1.00%	0.00%	14.84%	0.04%
Baker Hughes Co	BKR	992.0687	69.67	69,117.43	0.14%	1.32%	0.00%	12.14%	0.02%
Builders FirstSource Inc	BLDR	107.55988	79.09	8,506.91	0.02%			3.64%	0.00%
Blackrock Inc	BLK	155.36497	1065.6	165,556.91	0.33%	2.15%	0.01%	12.02%	0.04%
Bristol-Myers Squibb Co	BMY	2042.07125	60.59	123,729.10	0.25%	4.16%	0.01%	9.50%	0.02%
Broadridge Financial Solutions Inc	BR	115.6583	153.98	17,809.07	0.04%	2.53%	0.00%	9.50%	0.00%
Berkshire Hathaway Inc	BRK/B	1390.7224	473.6	658,646.13	1.32%			9.50%	0.13%
Brown & Brown Inc	BRO	338.94784	60.15	20,387.71	0.04%	1.10%	0.00%	7.16%	0.00%
Boston Scientific Corp	BSX	1486.17517	57.61	85,618.55	0.17%			10.78%	0.02%
Blackstone Inc	BX	785.49703	125.58	98,642.72	0.20%	3.69%	0.01%	19.00%	0.04%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg/Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
BXP Inc	BXP	158.67596	58.46	9,276.20	0.02%	4.79%	0.00%	0.68%	0.00%
Citigroup Inc	C	1714.90745	127.98	219,473.86		1.88%		24.31%	
Conagra Brands Inc	CAG	478.43716	14.35	6,865.57		9.76%		-6.05%	
Cardinal Health Inc	CAH	234.20586	192.88	45,173.63	0.09%	1.06%	0.00%	14.30%	0.01%
Carrier Global Corp	CARR	830.58042	67.17	55,790.09	0.11%	1.43%	0.00%	10.20%	0.01%
Casey's General Stores Inc	CASY	36.95903	821.58	30,364.80	0.06%	0.28%	0.00%	15.36%	0.01%
Caterpillar Inc	CAT	465.28733	890.11	414,156.91	0.83%	0.68%	0.01%	17.18%	0.14%
Chubb Ltd	CB	387.86011	327	126,830.26	0.25%	1.19%	0.00%	6.81%	0.02%
Cboe Global Markets Inc	CBOE	104.74227	300.09	31,432.11	0.06%	0.96%	0.00%	14.30%	0.01%
CBRE Group Inc	CBRE	292.81658	142.73	41,793.71	0.08%			9.00%	0.01%
Crown Castle Inc	CCI	436.36735	88.78	38,740.69	0.08%	4.79%	0.00%	4.00%	0.00%
Carnival Corp	CCL	1239.00021	26.51	32,845.90		2.26%			
Cadence Design Systems Inc	CDNS	276.09207	329.59	90,997.19	0.18%			13.77%	0.03%
CDW Corp/DE	CDW	127.97446	136.91	17,520.98	0.04%	1.84%	0.00%	6.88%	0.00%
Constellation Energy Corp	CEG	362.29467	313	113,398.23		0.55%		21.62%	
CF Industries Holdings Inc	CF	153.61643	124.2	19,079.16		1.61%		-13.27%	
Citizens Financial Group Inc	CFG	424.99389	65.05	27,645.85	0.06%	2.83%	0.00%	18.71%	0.01%
Church & Dwight Co Inc	CHD	236.87509	97.06	22,991.10	0.05%	1.27%	0.00%	7.11%	0.00%
CH Robinson Worldwide Inc	CHRW	117.85041	181.81	21,426.38	0.04%	1.39%	0.00%	14.72%	0.01%
Charter Communications Inc	CHTR	122.98454	165.17	20,313.36	0.04%			12.16%	0.00%
Cigna Group/The	CI	264.5324	290.58	76,867.82	0.15%	2.15%	0.00%	9.19%	0.01%
Ciena Corp	CIEN	141.39843	527.58	74,598.98				41.82%	
Cincinnati Financial Corp	CINF	154.68674	163.6	25,306.75	0.05%	2.30%	0.00%	7.43%	0.00%
Colgate-Palmolive Co	CL	802.30192	85.36	68,484.49	0.14%	2.48%	0.00%	7.37%	0.01%
Clorox Co/The	CLX	120.92135	96.44	11,661.65	0.02%	5.14%	0.00%	1.51%	0.00%
Comcast Corp	CMCSA	3562.78418	27.04	96,337.68	0.19%	4.88%	0.01%	1.51%	0.00%
CME Group Inc	CME	362.35621	287.82	104,293.36	0.21%	1.81%	0.00%	5.76%	0.01%
Chipotle Mexican Grill Inc	CMG	1282.734	33.99	43,600.13	0.09%			13.60%	0.01%
Cummins Inc	CMI	138.25742	671.01	92,772.11	0.19%	1.19%	0.00%	11.15%	0.02%
CMS Energy Corp	CMS	308.9196	76.74	23,706.49	0.05%	2.97%	0.00%	7.71%	0.00%
Centene Corp	CNC	493.797	53.69	26,511.96				28.78%	
CenterPoint Energy Inc	CNP	652.87158	43.65	28,497.84	0.06%	2.11%	0.00%	8.01%	0.00%
Capital One Financial Corp	COF	632.57143	191.3	121,010.91	0.24%	1.67%	0.00%	13.03%	0.03%
Coherent Corp	COHR	187.48185	319.71	59,939.82				38.12%	
Coinbase Global Inc	COIN	223.04128	187.77	41,880.46	0.08%			19.07%	0.02%
Cooper Cos Inc/The	COO	195.1144	62.9	12,272.70	0.02%			8.70%	0.00%
ConocoPhillips	COP	1218.29401	125.78	153,237.02	0.31%	2.67%	0.01%	2.50%	0.01%
Cencora Inc	COR	194.53068	308.01	59,917.39	0.12%	0.78%	0.00%	8.46%	0.01%
Costco Wholesale Corp	COST	443.65254	1013.06	449,446.64	0.90%	0.58%	0.01%	10.59%	0.10%
Corpay Inc	CPAY	66.13199	306.47	20,267.47	0.04%			13.06%	0.01%
Campbell's Company/The	CPB	298.14649	20.79	6,198.47		7.50%		-1.47%	
Copart Inc	CPRT	963.30839	33.11	31,895.14	0.06%			7.00%	0.00%
Camden Property Trust	CPT	104.727	105.02	10,998.43		4.04%		-1.66%	
CRH PLC	CRH	668.20022	118.42	79,128.27	0.16%	1.32%	0.00%	9.98%	0.02%
Charles River Laboratories International Inc	CRL	49.34196	166.97	8,238.63	0.02%			6.21%	0.00%
Salesforce Inc	CRM	818.05374	176.53	144,411.03		1.00%		21.00%	
Crowdstrike Holdings Inc	CRWD	253.61409	445.75	113,048.48				30.00%	
Cisco Systems Inc	CSCO	3949.89304	91.5	361,415.21	0.72%	1.84%	0.01%	7.40%	0.05%
CoStar Group Inc	CSGP	408.35572	34.61	14,133.19				30.78%	
CSX Corp	CSX	1858.13886	45.43	84,415.25	0.17%	1.23%	0.00%	11.64%	0.02%
Cintas Corp	CTAS	400.08712	174.71	69,899.22	0.14%	1.03%	0.00%	12.18%	0.02%
Coterra Energy Inc	CTRA	759.35262	35.91	27,268.35	0.05%	2.45%	0.00%	3.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	473.86947	52.9	25,067.69	0.05%	2.50%	0.00%	9.00%	0.00%
Corteva Inc	CTVA	671.3565	81.01	54,386.59	0.11%	0.89%	0.00%	10.36%	0.01%
Carvana Co	CVNA	143.25768	395.8	56,701.39	0.11%			1.83%	0.00%
CVS Health Corp	CVS	1281.6044	83.29	106,744.83	0.21%	3.19%	0.01%	7.13%	0.02%
Chevron Corp	CVX	1991.8988	193.31	385,053.96	0.77%	3.68%	0.03%	9.81%	0.08%
Dominion Energy Inc	D	878.96472	64.5	56,693.22	0.11%	4.14%	0.00%	6.02%	0.01%
Delta Air Lines Inc	DAL	656.99434	67.99	44,669.05	0.09%	1.10%	0.00%	9.00%	0.01%
DoorDash Inc	DASH	411.36427	168.65	69,376.58				39.94%	
DuPont de Nemours Inc	DD	409.86742	45.66	18,714.55	0.04%	1.75%	0.00%	11.52%	0.00%
Datadog Inc	DDOG	330.77583	132.19	43,725.26	0.09%			19.94%	0.02%
Deere & Co	DE	270.10728	589.87	159,328.18	0.32%	1.10%	0.00%	9.67%	0.03%
Deckers Outdoor Corp	DECK	141.94997	102.2	14,507.29	0.03%			8.69%	0.00%
Dell Technologies Inc	DELL	325.65462	208.95	68,045.53	0.14%	1.21%	0.00%	15.59%	0.02%
Dollar General Corp	DG	220.22632	115.88	25,519.83	0.05%	2.04%	0.00%	7.41%	0.00%
Quest Diagnostics Inc	DGX	110.69643	194.2	21,497.25	0.04%	1.77%	0.00%	7.52%	0.00%
DR Horton Inc	DHI	283.57961	153.86	43,631.56	0.09%	1.17%	0.00%	5.87%	0.01%
Danaher Corp	DHR	707.77063	178.95	126,655.55	0.25%	0.89%	0.00%	6.25%	0.02%
Walt Disney Co/The	DIS	1771.51985	103.75	183,795.18	0.37%	1.45%	0.01%	13.91%	0.05%
Digital Realty Trust Inc	DLR	348.95546	200.94	70,119.11	0.14%	2.43%	0.00%	7.07%	0.01%
Dollar Tree Inc	DLTR	197.29822	97.11	19,159.63				20.44%	
Healthpeak Properties Inc	DOC	695.25666	16.17	11,242.30	0.02%	7.54%	0.00%	5.09%	0.00%
Dover Corp	DOV	134.66141	226.41	30,488.69	0.06%	0.92%	0.00%	7.84%	0.00%
Dow Inc	DOW	720.74144	40.49	29,182.82		3.46%		36.23%	
Domino's Pizza Inc	DPZ	33.26187	339.42	11,289.74	0.02%	2.35%	0.00%	12.83%	0.00%
Darden Restaurants Inc	DRI	114.535	200.56	22,971.14	0.05%	2.99%	0.00%	10.31%	0.00%
DTE Energy Co	DTE	208.02812	151.69	31,555.79	0.06%	3.07%	0.00%	5.72%	0.00%
Duke Energy Corp	DUK	778.21667	129.55	100,817.97	0.20%	3.29%	0.01%	6.25%	0.01%
DaVita Inc	DVA	65.94434	155.14	10,230.60	0.02%			18.16%	0.00%
Devon Energy Corp	DVN	621.4403	51.37	31,923.39	0.06%	1.87%	0.00%	4.79%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg/Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Dexcom Inc	DXCM	385.87298	59.55	22,978.74				20.97%	
Electronic Arts Inc	EA	250.25371	202.37	50,643.84	0.10%	0.38%	0.00%	9.50%	0.01%
eBay Inc	EBAY	444	103.48	45,945.12	0.09%	1.20%	0.00%	12.91%	0.01%
Ecolab Inc	ECL	282.42377	260.6	73,599.63	0.15%	1.12%	0.00%	10.43%	0.02%
Consolidated Edison Inc	ED	368.42125	111.49	41,075.29	0.08%	3.18%	0.00%	6.69%	0.01%
Equifax Inc	EFX	119.07241	173.94	20,711.45	0.04%	1.29%	0.00%	10.30%	0.00%
Everest Group Ltd	EG	39.8	356.76	14,199.05	0.03%	2.24%	0.00%	9.49%	0.00%
Edison International	EIX	384.79394	69.49	26,739.33	0.05%	5.05%	0.00%	8.03%	0.00%
Estee Lauder Cos Inc/The	EL	247.2197	76.71	18,964.22		1.83%		23.64%	
Elevance Health Inc	ELV	217.16238	376.42	81,744.26	0.16%	1.83%	0.00%	4.40%	0.01%
EMCOR Group Inc	EME	44.44028	891.67	39,626.06	0.08%	0.18%	0.00%	16.50%	0.01%
Emerson Electric Co	EMR	562	140.44	78,927.28	0.16%	1.58%	0.00%	11.47%	0.02%
EOG Resources Inc	EOG	535.71581	140.57	75,305.57	0.15%	2.90%	0.00%	5.11%	0.01%
EPAM Systems Inc	EPAM	52.44431	113.78	5,967.11	0.01%			9.00%	0.00%
Equinix Inc	EQIX	98.62425	1082.83	106,793.30	0.21%	1.91%	0.00%	18.26%	0.04%
Equity Residential	EQR	374.67174	65.38	24,496.04	0.05%	4.30%	0.00%	3.62%	0.00%
EQT Corp	EQT	625.478	60.08	37,578.72	0.08%	1.10%	0.00%	11.03%	0.01%
Erie Indemnity Co	ERIE	46.18907	218.93	10,112.17	0.02%	2.67%	0.00%	18.00%	0.00%
Eversource Energy	ES	375.84535	70.7	26,572.27	0.05%	4.46%	0.00%	4.11%	0.00%
Essex Property Trust Inc	ESS	64.26287	263.21	16,914.63	0.03%	3.94%	0.00%	4.25%	0.00%
Eaton Corp PLC	ETN	387.98534	433.01	168,001.53	0.34%	1.02%	0.00%	13.50%	0.05%
Entergy Corp	ETR	457.79863	117.27	53,686.05	0.11%	2.18%	0.00%	7.35%	0.01%
Evergy Inc	EVRG	229.74594	82.84	19,032.15	0.04%	3.36%	0.00%	7.79%	0.00%
Edwards Lifesciences Corp	EW	576.54169	83.5	48,141.23	0.10%			10.28%	0.01%
Exelon Corp	EXC	1023.17509	45.99	47,055.82	0.09%	3.65%	0.00%	6.00%	0.01%
Expand Energy Corp	EXE	239.22885	102.15	24,437.23		2.25%			
Expeditors International of Washington Inc	EXPD	132.98401	147.89	19,667.01	0.04%	1.04%	0.00%	4.99%	0.00%
Expedia Group Inc	EXPE	114.49863	248.37	28,438.02		0.77%		20.10%	
Extra Space Storage Inc	EXR	211.19711	143.33	30,270.88	0.06%	4.52%	0.00%	0.77%	0.00%
Ford Motor Co	F	3913.84055	12.08	47,279.19		4.97%		22.42%	
Diamondback Energy Inc	FANG	281.31173	205.63	57,846.13	0.12%	2.04%	0.00%	12.83%	0.01%
Fastenal Co	FAST	1148.03506	44.93	51,581.22	0.10%	2.14%	0.00%	9.62%	0.01%
Freeport-McMoRan Inc	FCX	1437.5307	57.78	83,060.52		1.04%		23.79%	
FactSet Research Systems Inc	FDS	36.43113	227.58	8,291.00	0.02%	1.93%	0.00%	5.66%	0.00%
FedEx Corp	FDX	238.60676	403.31	96,232.49	0.19%	1.44%	0.00%	9.63%	0.02%
FirstEnergy Corp	FE	577.12618	47.52	27,425.04	0.05%	3.91%	0.00%	6.31%	0.00%
F5 Inc	FFIV	56.753	323.9	18,382.30	0.04%			5.95%	0.00%
Fair Isaac Corp	FICO	23.19091	1025	23,770.68				24.63%	
Fidelity National Information Services Inc	FIS	516.86918	46.53	24,049.92	0.05%	3.78%	0.00%	10.00%	0.00%
Fiserv Inc	FISV	533.94866	62.65	33,451.88	0.07%			5.50%	0.00%
Fifth Third Bancorp	FITB	905.5635	50.76	45,966.40	0.09%	3.15%	0.00%	10.00%	0.01%
Comfort Systems USA Inc	FIX	35.20242	1840.25	64,781.25		0.17%		23.50%	
Fox Corp	FOX	224.70222	57.02	12,812.52	0.03%	0.98%	0.00%	1.78%	0.00%
Fox Corp	FOXA	200.69386	63.49	12,742.05	0.03%	0.88%	0.00%	4.89%	0.00%
Federal Realty Investment Trust	FRT	86.38821	110.9	9,580.45	0.02%	4.08%	0.00%	3.33%	0.00%
First Solar Inc	FSLR	107.45336	201.89	21,693.76				26.00%	
Fortinet Inc	FTNT	732.10205	84.31	61,723.52	0.12%			12.50%	0.02%
Fortive Corp	FTV	304.86102	59.79	18,227.64	0.04%	0.40%	0.00%	6.50%	0.00%
General Dynamics Corp	GD	270.43019	344.3	93,109.11	0.19%	1.85%	0.00%	11.26%	0.02%
GoDaddy Inc	GDDY	132.6972	86.79	11,516.79	0.02%			5.50%	0.00%
General Electric Co	GE	1043.33724	289.93	302,494.77	0.61%	0.65%	0.00%	17.09%	0.10%
GE HealthCare Technologies Inc	GEHC	454.89179	60.84	27,675.62	0.06%	0.23%	0.00%	8.05%	0.00%
Gen Digital Inc	GEN	605.66377	19.29	11,683.25	0.02%	2.59%	0.00%	8.50%	0.00%
GE Vernova Inc	GEV	268.72	1083.46	291,147.37		0.18%		66.80%	
Gilead Sciences Inc	GILD	1241.20374	130.84	162,399.10	0.33%	2.51%	0.01%	11.22%	0.04%
General Mills Inc	GIS	533.68122	35.31	18,844.28		6.91%		-4.04%	
Globe Life Inc	GL	78.44455	154.3	12,103.99	0.02%	0.86%	0.00%	8.00%	0.00%
Corning Inc	GLW	859.01484	164.24	141,084.60		0.68%		30.91%	
General Motors Co	GM	901.6652	76.89	69,329.04	0.14%	0.94%	0.00%	12.33%	0.02%
Generac Holdings Inc	GNRC	58.81174	259.23	15,245.77	0.03%			18.50%	0.01%
Alphabet Inc	GOOG	5456	381.94	2,083,864.64	4.17%	0.23%	0.01%	17.10%	0.71%
Alphabet Inc	GOOGL	5824	384.8	2,241,075.20	4.49%	0.23%	0.01%	17.69%	0.79%
Genuine Parts Co	GPC	137.62455	107.23	14,757.48	0.03%	3.96%	0.00%	2.00%	0.00%
Global Payments Inc	GPN	275.24301	71.96	19,806.49	0.04%	1.39%	0.00%	8.00%	0.00%
Garmin Ltd	GRMN	192.85621	251.14	48,433.91	0.10%	1.67%	0.00%	8.19%	0.01%
Goldman Sachs Group Inc/The	GS	294.99394	923.77	272,506.55	0.55%	1.95%	0.01%	13.14%	0.07%
WW Grainger Inc	GWW	47.32999	1161.35	54,966.68	0.11%	0.86%	0.00%	6.88%	0.01%
Halliburton Co	HAL	835.39774	42.3	35,337.32	0.07%	1.61%	0.00%	8.69%	0.01%
Hasbro Inc	HAS	141.52154	95.84	13,563.42	0.03%	2.92%	0.00%	7.20%	0.00%
Huntington Bancshares Inc/OH	HBAN	2027.13059	16.76	33,974.71	0.07%	3.70%	0.00%	9.51%	0.01%
HCA Healthcare Inc	HCA	221.8398	434.45	96,378.30	0.19%	0.72%	0.00%	9.84%	0.02%
Home Depot Inc/The	HD	996.02766	328.8	327,493.89	0.66%	2.83%	0.02%	5.80%	0.04%
Hartford Insurance Group Inc/The	HIG	274.13082	136.81	37,503.84	0.08%	1.75%	0.00%	5.22%	0.00%
Huntington Ingalls Industries Inc	HII	39.37717	364.29	14,344.71	0.03%	1.52%	0.00%	15.28%	0.00%
Hilton Worldwide Holdings Inc	HLT	227.64837	324.07	73,774.01	0.15%	0.19%	0.00%	12.97%	0.02%
Honeywell International Inc	HON	633.65312	214.33	135,810.87	0.27%	2.22%	0.01%	7.69%	0.02%
Robinhood Markets Inc	HOOD	791.1847	72.89	57,669.45				23.14%	
Hewlett Packard Enterprise Co	HPE	1326.85409	28.77	38,173.59	0.08%	1.98%	0.00%	12.68%	0.01%
HP Inc	HPQ	914.5502	20.86	19,077.52	0.04%	5.75%	0.00%	3.14%	0.00%
Hormel Foods Corp	HRL	550.28421	21.47	11,814.60	0.02%	5.45%	0.00%	5.81%	0.00%
Henry Schein Inc	HSIC	114.74805	74.59	8,559.06	0.02%			8.76%	0.00%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg/Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Host Hotels & Resorts Inc	HST	687.3333	21.13	14,523.35	0.03%	3.79%	0.00%	4.34%	0.00%
Hershey Co/The	HSY	148.22986	185.74	27,532.21	0.06%	3.13%	0.00%	13.00%	0.01%
Hubbell Inc	HUBB	53.02473	508.17	26,945.58	0.05%	1.12%	0.00%	7.50%	0.00%
Humana Inc	HUM	120.0615	236.44	28,387.34	0.06%	1.50%	0.00%	9.20%	0.01%
Howmet Aerospace Inc	HWM	400.71356	243.04	97,389.42		0.20%		20.50%	
Interactive Brokers Group Inc	IBKR	445.61648	79.5	35,426.51	0.07%	0.44%	0.00%	14.41%	0.01%
International Business Machines Corp	IBM	939.88528	230.98	217,094.70	0.43%	2.93%	0.01%	7.29%	0.03%
Intercontinental Exchange Inc	ICE	565.51249	158.09	89,401.87	0.18%	1.32%	0.00%	11.52%	0.02%
IDEXX Laboratories Inc	IDXX	79.51894	560.8	44,594.22	0.09%			11.91%	0.01%
IDEX Corp	IEX	74.01505	217.85	16,124.18	0.03%	1.30%	0.00%	4.50%	0.00%
International Flavors & Fragrances Inc	IFF	255.43782	70.2	17,931.73	0.04%	2.28%	0.00%	5.83%	0.00%
Incyte Corp	INCY	199.78216	95.27	19,033.25	0.04%			18.93%	0.01%
Intel Corp	INTC	5026	94.48	474,856.48				47.81%	
Intuit Inc	INTU	276.55	388.5	107,439.68	0.22%	1.24%	0.00%	13.99%	0.03%
Invitation Homes Inc	INVH	594.04196	28.77	17,090.59	0.03%	4.17%	0.00%	6.10%	0.00%
International Paper Co	IP	529.48621	30.42	16,106.97	0.03%	6.08%	0.00%	9.50%	0.00%
IQVIA Holdings Inc	IQV	169.7	158.37	26,875.39	0.05%			7.45%	0.00%
Ingersoll Rand Inc	IR	391.33683	79.86	31,252.16	0.06%	0.10%	0.00%	8.50%	0.01%
Iron Mountain Inc	IRM	297.52468	125.99	37,485.13	0.08%	2.74%	0.00%	9.50%	0.01%
Intuitive Surgical Inc	ISRG	354.16284	457.61	162,068.46	0.32%			15.06%	0.05%
Gartner Inc	IT	67.51019	148.49	10,024.59	0.02%			6.23%	0.00%
Illinois Tool Works Inc	ITW	288.07808	258.01	74,327.03	0.15%	2.50%	0.00%	8.86%	0.01%
Invesco Ltd	IVZ	443.32083	26.21	11,619.44		3.28%		22.56%	
Jacobs Solutions Inc	J	117.44671	129.41	15,198.78	0.03%	1.11%	0.00%	10.29%	0.00%
JB Hunt Transport Services Inc	JBHT	94.2992	251.53	23,719.08	0.05%	0.72%	0.00%	12.98%	0.01%
Jabil Inc	JBL	105.50262	337.49	35,606.08	0.07%	0.09%	0.00%	15.78%	0.01%
Johnson Controls International plc	JCI	612.06621	146.03	89,380.03	0.18%	1.10%	0.00%	17.45%	0.03%
Jack Henry & Associates Inc	JKHY	72.16737	153.75	11,095.73	0.02%	1.59%	0.00%	6.50%	0.00%
Johnson & Johnson	JNJ	2407.21697	229.85	553,298.82	1.11%	2.33%	0.03%	7.24%	0.08%
JPMorgan Chase & Co	JPM	2682.21963	313.23	840,151.65	1.68%	1.92%	0.03%	9.85%	0.17%
Keurig Dr Pepper Inc	KDP	1360.55947	29.4	40,000.45	0.08%	3.13%	0.00%	10.22%	0.01%
KeyCorp	KEY	1087.293	22.11	24,040.05	0.05%	3.71%	0.00%	12.92%	0.01%
Keysight Technologies Inc	KEYS	171.5025	349.91	60,010.44	0.12%			12.73%	0.02%
Kraft Heinz Co/The	KHC	1185.76231	22.66	26,869.37		7.06%		-0.33%	
Kimco Realty Corp	KIM	674.40321	23.64	15,942.89	0.03%	4.40%	0.00%	10.16%	0.00%
KKR & Co Inc	KKR	891.55089	104.34	93,024.42	0.19%	0.71%	0.00%	7.00%	0.01%
KLA Corp	KLAC	130.62752	1750.35	228,643.88	0.46%	0.43%	0.00%	15.00%	0.07%
Kimberly-Clark Corp	KMB	331.94036	98.43	32,672.89	0.07%	5.20%	0.00%	4.96%	0.00%
Kinder Morgan Inc	KMI	2224.82576	32.87	73,130.02	0.15%	3.62%	0.01%	7.92%	0.01%
Coca-Cola Co/The	KO	4302.48242	78.76	338,863.52	0.68%	2.69%	0.02%	7.36%	0.05%
Kroger Co/The	KR	612.57561	68.07	41,698.02	0.08%	2.06%	0.00%	6.00%	0.01%
Kenvue Inc	KVUE	1919.91631	17.53	33,656.13	0.07%	4.73%	0.00%	13.12%	0.01%
Loews Corp	L	205.7677	112.61	23,171.50	0.05%	0.22%	0.00%	14.00%	0.01%
Leidos Holdings Inc	LDOS	125.92855	149.22	18,791.06	0.04%	1.15%	0.00%	8.71%	0.00%
Lennar Corp	LEN	215.2444	90.3	19,436.57	0.04%	2.21%	0.00%	2.46%	0.00%
Labcorp Holdings Inc	LH	82.18705	256.8	21,105.63	0.04%	1.12%	0.00%	6.58%	0.00%
L3Harris Technologies Inc	LHX	186.29495	320.55	59,716.85	0.12%	1.56%	0.00%	13.86%	0.02%
Lennox International Inc	LII	34.79997	534.89	18,614.16	0.04%	0.97%	0.00%	11.00%	0.00%
Linde PLC	LIN	462.64217	501.14	231,848.50	0.46%	1.28%	0.01%	8.17%	0.04%
Lumentum Holdings Inc	LITE	71.4	902.32	64,425.65					
Eli Lilly & Co	LLY	941.74141	934.6	880,151.52	1.76%	0.74%	0.01%	20.00%	0.35%
Lockheed Martin Corp	LMT	230.56361	517.97	119,425.03	0.24%	2.66%	0.01%	16.33%	0.04%
Alliant Energy Corp	LNT	258.27648	73.43	18,965.24	0.04%	2.91%	0.00%	6.48%	0.00%
Lowe's Cos Inc	LOW	560.06289	238.79	133,737.42	0.27%	2.01%	0.01%	4.58%	0.01%
Lam Research Corp	LRCX	1250.571	257.86	322,472.24		0.40%		26.70%	
Lululemon Athletica Inc	LULU	109.95744	137.7	15,141.14	0.03%			2.00%	0.00%
Southwest Airlines Co	LUV	488.77371	37.92	18,534.30		1.90%		48.52%	
Las Vegas Sands Corp	LVS	662.63733	54.61	36,186.62		2.20%		20.86%	
LyondellBasell Industries NV	LYB	322.76929	74.6	24,078.59		3.70%		22.59%	
Live Nation Entertainment Inc	LYV	235.12481	157.94	37,135.61				81.03%	
Mastercard Inc	MA	877.03623	502.92	441,079.06	0.88%	0.69%	0.01%	13.35%	0.12%
Mid-America Apartment Communities Inc	MAA	116.3848	129.18	15,034.59	0.03%	4.74%	0.00%	1.09%	0.00%
Marriott International Inc/MD	MAR	264.93199	361.69	95,823.25	0.19%	0.74%	0.00%	9.00%	0.02%
Masco Corp	MAS	201.73444	71.82	14,488.57	0.03%	1.78%	0.00%	8.65%	0.00%
McDonald's Corp	MCD	710.82763	293.59	208,691.88	0.42%	2.53%	0.01%	8.75%	0.04%
Microchip Technology Inc	MCHP	541.13546	92.91	50,276.90	0.10%	1.96%	0.00%	19.73%	0.02%
McKesson Corp	MCK	122.48746	815.2	99,851.78	0.20%	0.40%	0.00%	12.89%	0.03%
Moody's Corp	MCO	174.7	461.85	80,685.20	0.16%	0.89%	0.00%	11.11%	0.02%
Mondelez International Inc	MDLZ	1283.64977	61.44	78,867.44	0.16%	3.26%	0.01%	7.36%	0.01%
Medtronic PLC	MDT	1283.88496	80.97	103,956.17	0.21%	3.51%	0.01%	7.02%	0.01%
MetLife Inc	MET	647.0462	80.1	51,828.40	0.10%	2.96%	0.00%	10.43%	0.01%
Meta Platforms Inc	META	2196.04559	611.91	1,343,782.26	2.69%	0.34%	0.01%	15.42%	0.41%
MGM Resorts International	MGM	255.85124	38.94	9,962.85				25.00%	
McCormick & Co Inc/MD	MKC	253.94312	50.84	12,910.47	0.03%	3.78%	0.00%	5.64%	0.00%
Martin Marietta Materials Inc	MLM	60.0459	619.07	37,172.62	0.07%	0.54%	0.00%	11.49%	0.01%
3M Co	MMM	521.56726	146.52	76,420.03		2.13%		30.85%	
Monster Beverage Corp	MNST	977.90602	77.07	75,367.22	0.15%			10.10%	0.02%
Altria Group Inc	MO	1669.89124	72.65	121,317.60	0.24%	5.84%	0.01%	5.01%	0.01%
Mosaic Co/The	MOS	317.84664	23.27	7,396.29	0.01%	3.78%	0.00%	10.68%	0.00%
Marathon Petroleum Corp	MPC	294.49688	248.29	73,120.63	0.15%	1.61%	0.00%	10.12%	0.01%
Monolithic Power Systems Inc	MPWR	49.12927	1614.41	79,314.78	0.16%	0.50%	0.00%	15.00%	0.02%

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Merck & Co Inc	MRK	2469.87921	109.18	269,661.41	0.54%	3.11%	0.02%	12.50%	0.07%
Moderna Inc	MRNA	396.58686	45.94	18,219.20				23.66%	
Marsh & McLennan Cos Inc	MRSH	481.7945	167.71	80,801.76	0.16%	2.15%	0.00%	7.75%	0.01%
Morgan Stanley	MS	1580	190.59	301,132.20	0.60%	2.10%	0.01%	12.57%	0.08%
MSCI Inc	MSCI	73.12021	591.41	43,244.02	0.09%	1.39%	0.00%	11.36%	0.01%
Microsoft Corp	MSFT	7428.4347	407.78	3,029,167.10	6.07%	0.89%	0.05%	14.96%	0.91%
Motorola Solutions Inc	MSI	166.20361	439.03	72,968.37	0.15%	1.10%	0.00%	9.15%	0.01%
M&T Bank Corp	MTB	146.917	218.63	32,120.46	0.06%	2.74%	0.00%	8.88%	0.01%
Mettler-Toledo International Inc	MTD	20.24851	1276.61	25,849.45	0.05%			8.88%	0.00%
Micron Technology Inc	MU	1127.73405	517.16	583,218.94		0.12%		101.94%	
Norwegian Cruise Line Holdings Ltd	NCLH	459.10543	18.18	8,346.54	0.02%			14.09%	0.00%
Nasdaq Inc	NDAQ	565.5408	91.91	51,978.85	0.10%	1.35%	0.00%	11.32%	0.01%
Nordson Corp	NDSN	55.7836	288.45	16,090.78	0.03%	1.14%	0.00%	8.00%	0.00%
NextEra Energy Inc	NEE	2085.34146	97.88	204,113.22	0.41%	2.55%	0.01%	8.05%	0.03%
Newmont Corp	NEM	1067.55276	111.09	118,594.44	0.24%	0.94%	0.00%	15.45%	0.04%
Netflix Inc	NFLX	4210.79853	93.61	394,172.85				22.26%	
NiSource Inc	NI	479.35779	48.28	23,143.39	0.05%	2.49%	0.00%	7.86%	0.00%
NIKE Inc	NKE	1199.49928	44.36	53,209.79		3.70%		-0.77%	
Northrop Grumman Corp	NOC	142.03348	579.48	82,305.56	0.16%	1.59%	0.00%	7.60%	0.01%
ServiceNow Inc	NOW	1031	88.31	91,047.61	0.18%			17.00%	0.03%
NRG Energy Inc	NRG	214.55659	155.105	33,278.80	0.07%	1.22%	0.00%	20.00%	0.01%
Norfolk Southern Corp	NSC	224.594	315.83	70,933.52	0.14%	1.71%	0.00%	8.50%	0.01%
NetApp Inc	NTAP	197.3304	110.77	21,858.29	0.04%	1.88%	0.00%	6.99%	0.00%
Northern Trust Corp	NTRS	185.04726	166.34	30,780.76	0.06%	1.92%	0.00%	11.29%	0.01%
Nucor Corp	NUE	227.63611	225.29	51,284.14	0.10%	0.99%	0.00%	17.49%	0.02%
NVIDIA Corp	NVDA	24300	199.57	4,849,551.00		0.02%		35.78%	
NVR Inc	NVR	2.73183	6315.87	17,253.88	0.03%			2.81%	0.00%
News Corp	NWS	184.3403	30.48	5,618.69		0.66%			
News Corp	NWSA	367.8178	26.32	9,680.96	0.02%	0.76%	0.00%	19.50%	0.00%
NXP Semiconductors NV	NXPI	252.47108	293.59	74,122.98	0.15%	1.38%	0.00%	12.94%	0.02%
Realty Income Corp	O	932.45063	64.24	59,900.63	0.12%	5.05%	0.01%	4.16%	0.00%
Old Dominion Freight Line Inc	ODFL	208.29212	212.43	44,247.50	0.09%	0.55%	0.00%	9.83%	0.01%
ONEOK Inc	OKE	630.03285	92.46	58,252.84	0.12%	4.63%	0.01%	12.50%	0.01%
Omnicom Group Inc	OMC	285.0062	76.72	21,865.68	0.04%	4.17%	0.00%	11.47%	0.01%
ON Semiconductor Corp	ON	393.32732	100.81	39,651.33	0.08%			15.01%	0.01%
Oracle Corp	ORCL	2876.046	161.39	464,165.06		1.24%		21.11%	
O'Reilly Automotive Inc	ORLY	836.69947	99.4	83,167.93	0.17%			9.74%	0.02%
Otis Worldwide Corp	OTIS	383.71608	77.88	29,883.81	0.06%	2.26%	0.00%	9.50%	0.01%
Occidental Petroleum Corp	OXY	991.69518	60.58	60,076.89		1.72%			
Palo Alto Networks Inc	PANW	816	179.32	146,325.12				22.14%	
Paychex Inc	PAYX	358.29088	92.63	33,188.48	0.07%	4.66%	0.00%	7.50%	0.00%
PACCAR Inc	PCAR	526.28623	118.8	62,522.80	0.13%	1.18%	0.00%	9.14%	0.01%
PG&E Corp	PCG	2202.22473	16.62	36,600.98	0.07%	1.20%	0.00%	9.26%	0.01%
Public Service Enterprise Group Inc	PEG	498.73991	81.66	40,727.10	0.08%	3.28%	0.00%	7.27%	0.01%
PepsiCo Inc	PEP	1366.76832	158.49	216,619.11	0.43%	3.59%	0.02%	5.74%	0.02%
Pfizer Inc	PFE	5688.35613	26.7	151,879.11	0.30%	6.44%	0.02%	0.01%	0.00%
Principal Financial Group Inc	PFG	216.01238	100.91	21,797.81	0.04%	3.25%	0.00%	7.67%	0.00%
Procter & Gamble Co/The	PG	2328.59898	147.09	342,513.62	0.69%	2.96%	0.02%	3.95%	0.03%
Progressive Corp/The	PGR	584.4	201.28	117,628.03	0.24%	0.20%	0.00%	8.01%	0.02%
Parker-Hannifin Corp	PH	126.21653	909.42	114,783.84	0.23%	0.88%	0.00%	10.01%	0.02%
PulteGroup Inc	PHM	190.48635	122.36	23,307.91	0.05%	0.85%	0.00%	3.89%	0.00%
Packaging Corp of America	PKG	89.02795	213.45	19,003.02	0.04%	2.34%	0.00%	7.31%	0.00%
Prologis Inc	PLD	932.23068	142.02	132,395.40	0.27%	3.01%	0.01%	5.68%	0.02%
Palantir Technologies Inc	PLTR	2295.91577	139.11	319,384.84				47.57%	
Philip Morris International Inc	PM	1558.55885	165.07	257,271.31	0.52%	3.56%	0.02%	7.36%	0.04%
PNC Financial Services Group Inc/The	PNC	402	223	89,646.00	0.18%	3.05%	0.01%	12.03%	0.02%
Pentair PLC	PNR	161.60554	80.71	13,043.18	0.03%	1.34%	0.00%	11.81%	0.00%
Pinnacle West Capital Corp	PNW	121.02565	103.72	12,552.78	0.03%	3.51%	0.00%	6.31%	0.00%
Insulet Corp	PODD	69.26371	172.14	11,923.06				28.35%	
Pool Corp	POOL	36.443	213.32	7,774.02	0.02%	2.44%	0.00%	3.98%	0.00%
PPG Industries Inc	PPG	222.9	108.5	24,184.65	0.05%	2.62%	0.00%	6.08%	0.00%
PPL Corp	PPL	751.307	37.44	28,128.93	0.06%	3.04%	0.00%	7.51%	0.00%
Prudential Financial Inc	PRU	347.8187	98.11	34,124.49	0.07%	5.71%	0.00%	7.45%	0.01%
Public Storage	PSA	175.54575	302.45	53,093.81	0.11%	3.97%	0.00%	4.96%	0.01%
Paramount Skydance Corp	PSKY	1080.24102	10.24	11,061.67		1.95%		25.16%	
Phillips 66	PSX	400.93502	179.15	71,827.51		2.84%		48.18%	
PTC Inc	PTC	118.99612	136.3	16,219.17	0.03%			7.81%	0.00%
Quanta Services Inc	PWR	150.06015	727.77	109,209.28	0.22%	0.06%	0.00%	17.11%	0.04%
PayPal Holdings Inc	PYPL	899.67397	50.14	45,109.65	0.09%	1.12%	0.00%	5.91%	0.01%
Qnity Electronics Inc	Q	209.44158	140.66	29,460.05		0.23%			
QUALCOMM Inc	QCOM	1054	179.58	189,277.32	0.38%	2.05%	0.01%	3.26%	0.01%
Royal Caribbean Cruises Ltd	RCL	268.19498	263.76	70,739.11	0.14%	2.27%	0.00%	14.06%	0.02%
Regency Centers Corp	REG	183.08337	77.85	14,253.04	0.03%	3.88%	0.00%	5.65%	0.00%
Regeneron Pharmaceuticals Inc	REGN	103.02189	707.06	72,842.66	0.15%	0.53%	0.00%	9.87%	0.01%
Regions Financial Corp	RF	854.31627	28.55	24,390.73	0.05%	3.71%	0.00%	8.58%	0.00%
Raymond James Financial Inc	RJF	194.6	158.32	30,809.07	0.06%	1.36%	0.00%	12.33%	0.01%
Ralph Lauren Corp	RL	38.65514	358.64	13,863.28	0.03%	1.02%	0.00%	17.07%	0.00%
ResMed Inc	RMD	145.6784	213.81	31,147.50	0.06%	1.12%	0.00%	10.11%	0.01%
Rockwell Automation Inc	ROK	112.35791	408.91	45,944.27	0.09%	1.35%	0.00%	12.23%	0.01%
Rollins Inc	ROL	481.46366	55.73	26,831.97	0.05%	1.31%	0.00%	11.55%	0.01%
Roper Technologies Inc	ROP	102.4	354.81	36,332.54	0.07%	1.03%	0.00%	8.00%	0.01%

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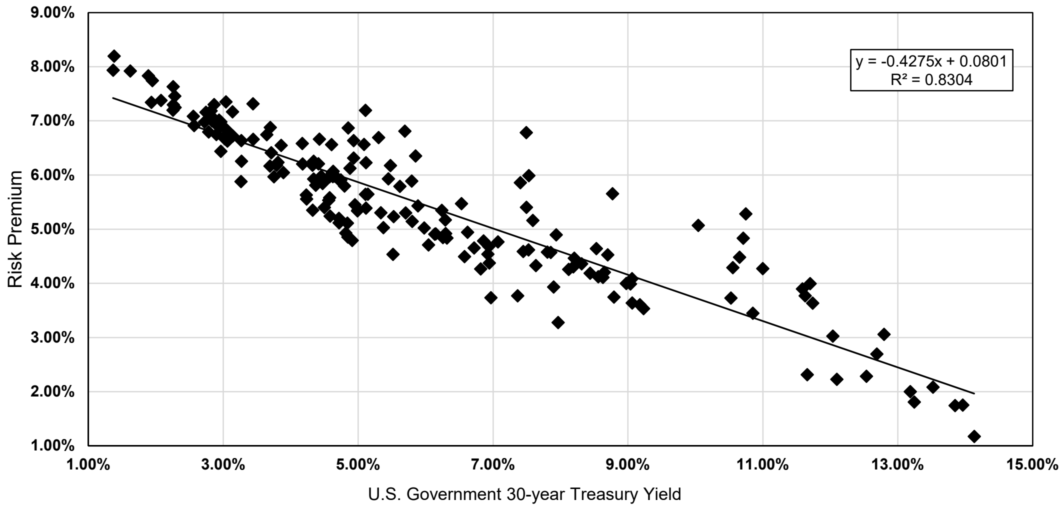
Ross Stores Inc	ROST	322.14815	227.79	73,382.13	0.15%	0.78%	0.00%	9.34%	0.01%
Republic Services Inc	RSG	308.95619	209.22	64,639.81	0.13%	1.19%	0.00%	8.25%	0.01%
RTX Corp	RTX	1346.68343	176.07	237,110.55	0.47%	1.66%	0.01%	11.06%	0.05%
Revvity Inc	RVTY	111.80333	86.62	9,684.40	0.02%	0.32%	0.00%	6.86%	0.00%
EchoStar Corp	SATS	157.52739	123.14	19,397.92					
SBA Communications Corp	SBAC	106.063	221.2	23,461.14	0.05%	2.26%	0.00%	5.51%	0.00%
Starbucks Corp	SBUX	1139.7	105.33	120,044.60	0.24%	2.35%	0.01%	10.57%	0.03%
Charles Schwab Corp/The	SCHW	1738.09944	91.64	159,279.43	0.32%	1.40%	0.00%	13.30%	0.04%
Sherwin-Williams Co/The	SHW	246.63562	321.61	79,320.48	0.16%	0.99%	0.00%	10.43%	0.02%
J M Smucker Co/The	SJM	106.64832	98.03	10,454.73	0.02%	4.49%	0.00%	4.51%	0.00%
SLB Ltd	SLB	1495.05766	56.88	85,038.88	0.17%	2.07%	0.00%	6.73%	0.01%
Super Micro Computer Inc	SMCI	600.48195	27.4	16,453.21				27.06%	
Snap-on Inc	SNA	51.80192	383.4	19,860.86	0.04%	2.55%	0.00%	4.47%	0.00%
Sandisk Corp/DE	SNDK	147.60097	1096.51	161,845.94					
Synopsys Inc	SNPS	191.56203	482.6	92,447.84	0.19%			13.23%	0.02%
Southern Co/The	SO	1128.31983	96.7	109,108.53	0.22%	3.14%	0.01%	7.81%	0.02%
Solventum Corp	SOLV	173.40525	67.36	11,680.58	0.02%			9.40%	0.00%
Simon Property Group Inc	SPG	324.84019	203.71	66,173.20	0.13%	4.32%	0.01%	3.50%	0.00%
S&P Global Inc	SPGI	296	431.23	127,644.08	0.26%	0.90%	0.00%	10.65%	0.03%
Sempra	SRE	653.33256	95.12	62,144.99	0.12%	2.76%	0.00%	7.57%	0.01%
STERIS PLC	STE	98.07503	216.88	21,270.51	0.04%	1.16%	0.00%	8.00%	0.00%
Steel Dynamics Inc	STLD	144.21278	228.66	32,975.69	0.07%	0.93%	0.00%	16.16%	0.01%
State Street Corp	STT	276.76703	152.84	42,301.07	0.08%	2.20%	0.00%	12.91%	0.01%
Seagate Technology Holdings PLC	STX	224.22899	673.64	151,049.62		0.44%		50.16%	
Constellation Brands Inc	STZ	172.17254	156.58	26,958.78	0.05%	2.63%	0.00%	3.67%	0.00%
Smurfit Westrock PLC	SW	524.25374	38.39	20,126.10		4.71%		43.72%	
Stanley Black & Decker Inc	SWK	155.45556	78.16	12,150.41	0.02%	4.25%	0.00%	20.00%	0.00%
Skyworks Solutions Inc	SWKS	150.40596	70.17	10,553.99		4.05%		-4.65%	
Synchrony Financial	SYF	336.95134	76.2	25,675.69	0.05%	1.57%	0.00%	8.83%	0.00%
Stryker Corp	SYK	382.98425	315.13	120,689.83	0.24%	1.12%	0.00%	10.05%	0.02%
Sysco Corp	SYY	478.18261	74.71	35,725.02	0.07%	2.94%	0.00%	6.50%	0.00%
AT&T Inc	T	6948.33884	26.13	181,560.09	0.36%	4.25%	0.02%	7.50%	0.03%
Molson Coors Beverage Co	TAP	175.21542	42.74	7,488.71	0.01%	4.49%	0.00%	0.82%	0.00%
TransDigm Group Inc	TDG	56.47356	1159.98	65,508.20	0.13%			13.09%	0.02%
Teledyne Technologies Inc	TDY	46.32914	645.85	29,921.68	0.06%			9.34%	0.01%
Bio-Techne Corp	TECH	156.45329	55.32	8,655.00	0.02%	0.58%	0.00%	13.00%	0.00%
TE Connectivity PLC	TEL	291.8958	211.66	61,782.67	0.12%	1.47%	0.00%	11.27%	0.01%
Teradyne Inc	TER	156.55943	343.47	53,773.47		0.15%		32.71%	
Truist Financial Corp	TFC	1241.00975	51.5	63,912.00	0.13%	4.04%	0.01%	9.02%	0.01%
Target Corp	TGT	454.17625	129.75	58,929.37	0.12%	3.51%	0.00%	4.50%	0.01%
TJX Cos Inc/The	TJX	1105.81426	156.75	173,336.39	0.35%	1.22%	0.00%	10.38%	0.04%
TKO Group Holdings Inc	TKO	74.96767	186.09	13,950.73		1.68%		80.07%	
Thermo Fisher Scientific Inc	TMO	371.62136	478.96	177,991.77	0.36%	0.39%	0.00%	8.05%	0.03%
T-Mobile US Inc	TMUS	1082.20472	195.5	211,571.02	0.42%	2.09%	0.01%	17.00%	0.07%
Texas Pacific Land Corp	TPL	68.94155	443.67	30,587.30	0.06%	0.54%	0.00%	10.00%	0.01%
Tapestry Inc	TPR	202.46422	145.04	29,365.41	0.06%	1.10%	0.00%	13.92%	0.01%
Targa Resources Corp	TRGP	214.80197	260.08	55,865.70	0.11%	1.92%	0.00%	17.00%	0.02%
Trimble Inc	TRMB	232.08873	67.32	15,624.21	0.03%			6.50%	0.00%
T Rowe Price Group Inc	TROW	214.26661	102.88	22,043.75	0.04%	5.05%	0.00%	2.88%	0.00%
Travelers Cos Inc/The	TRV	212.64469	305.14	64,886.40	0.13%	1.64%	0.00%	4.62%	0.01%
Tractor Supply Co	TSCO	526.00631	35.1	18,462.82	0.04%	2.74%	0.00%	8.12%	0.00%
Tesla Inc	TSLA	3755.72387	381.63	1,433,296.90	2.87%			10.50%	0.30%
Tyson Foods Inc	TSN	282.06996	64.07	18,072.22	0.04%	3.18%	0.00%	14.10%	0.01%
Trane Technologies PLC	TT	221.05548	492.54	108,878.67	0.22%	0.85%	0.00%	12.52%	0.03%
Trade Desk Inc/The	TTD	426.98914	23.59	10,072.67	0.02%			18.20%	0.00%
Take-Two Interactive Software Inc	TTWO	185.17546	213.76	39,583.11				75.23%	
Texas Instruments Inc	TXN	910.09279	281.08	255,808.88	0.51%	2.02%	0.01%	14.96%	0.08%
Textron Inc	TXT	173.88898	95.96	16,686.39	0.03%	0.08%	0.00%	11.82%	0.00%
Tyler Technologies Inc	TYL	42.16746	341.14	14,385.01	0.03%			9.00%	0.00%
United Airlines Holdings Inc	UAL	324.64938	90	29,218.44	0.06%			11.00%	0.01%
Uber Technologies Inc	UBER	2036.82486	74.61	151,967.50	0.30%			3.27%	0.01%
UDR Inc	UDR	324.91565	36.34	11,807.43	0.02%	4.79%	0.00%	3.84%	0.00%
Universal Health Services Inc	UHS	53.78098	168.27	9,049.73	0.02%	0.48%	0.00%	10.32%	0.00%
Ulta Beauty Inc	ULTA	43.56042	537.48	23,412.85	0.05%			8.85%	0.00%
UnitedHealth Group Inc	UNH	908.21318	370.48	336,474.82	0.67%	2.39%	0.02%	6.03%	0.04%
Union Pacific Corp	UNP	593.71321	269.48	159,993.84	0.32%	2.05%	0.01%	8.85%	0.03%
United Parcel Service Inc	UPS	745.6334	108.8	81,124.91	0.16%	6.03%	0.01%	4.66%	0.01%
United Rentals Inc	URI	62.64656	959.84	60,130.67	0.12%	0.82%	0.00%	12.13%	0.01%
US Bancorp	USB	1555	56.66	88,106.30	0.18%	3.67%	0.01%	9.64%	0.02%
Visa Inc	V	1659.70993	329.84	547,438.72	1.10%	0.81%	0.01%	12.19%	0.13%
VICI Properties Inc	VICI	1069.03019	29.2	31,215.68	0.06%	6.16%	0.00%	8.00%	0.01%
Valero Energy Corp	VLO	296.93278	252.58	74,999.28	0.15%	1.90%	0.00%	10.54%	0.02%
Veralto Corp	VLTO	245.59927	88.2	21,661.86	0.04%	0.59%	0.00%	8.50%	0.00%
Vulcan Materials Co	VMC	129.75489	301.74	39,152.24	0.08%	0.69%	0.00%	10.18%	0.01%
Verisk Analytics Inc	VRSK	131.02184	184.49	24,172.22	0.05%	1.08%	0.00%	9.24%	0.00%
VeriSign Inc	VRSN	91	268.66	24,448.06	0.05%	1.21%	0.00%	8.00%	0.00%
Vertiv Holdings Co	VRT	384.10882	328.49	126,175.91		0.08%		31.79%	
Vertex Pharmaceuticals Inc	VRTX	254.45696	427.38	108,749.82	0.22%			11.19%	0.02%
Vistra Corp	VST	338.54929	157.84	53,436.62		0.58%		32.00%	
Ventas Inc	VTR	486.16972	87.86	42,714.87	0.09%	2.37%	0.00%	16.78%	0.01%
Viatris Inc	VTRS	1164.42091	14.94	17,396.45	0.03%	3.21%	0.00%	3.33%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg/Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Verizon Communications Inc	VZ	4176	48.03	200,573.28	0.40%	5.89%	0.02%	4.85%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	169.67735	269.89	45,794.22	0.09%	0.46%	0.00%	14.09%	0.01%
Waters Corp	WAT	98.16549	309.23	30,355.71	0.06%			9.10%	0.01%
Warner Bros Discovery Inc	WBD	2506.67942	27.05	67,805.68					
Workday Inc	WDAY	210	122.4	25,704.00					
Western Digital Corp	WDC	339.03792	434.52	147,318.76		0.14%		55.92%	
WEC Energy Group Inc	WEC	325.69961	117.94	38,413.01	0.08%	3.23%	0.00%	7.08%	0.01%
Welltower Inc	WELL	705.91445	217.34	153,423.45		1.36%		22.52%	
Wells Fargo & Co	WFC	3060.18949	82.23	251,639.38	0.50%	2.19%	0.01%	10.21%	0.05%
Waste Management Inc	WM	401.57575	232.55	93,386.44	0.19%	1.63%	0.00%	9.01%	0.02%
Williams Cos Inc/The	WMB	1222.85695	76.31	93,316.21	0.19%	2.75%	0.01%	16.89%	0.03%
Walmart Inc	WMT	7970.99052	131.93	1,051,612.78	2.11%	0.75%	0.02%	9.89%	0.21%
W R Berkley Corp	WRB	390.019	66.83	26,064.97	0.05%	0.54%	0.00%	8.02%	0.00%
Williams-Sonoma Inc	WSM	119.01605	181.21	21,566.90	0.04%	1.68%	0.00%	6.12%	0.00%
West Pharmaceutical Services Inc	WST	70.6476	297.59	21,024.02	0.04%	0.30%	0.00%	9.41%	0.00%
Willis Towers Watson PLC	WTW	94.44798	256.2	24,197.57	0.05%	1.50%	0.00%	13.57%	0.01%
Weyerhaeuser Co	WY	721.04261	24.52	17,679.96	0.04%	3.43%	0.00%	17.11%	0.01%
Wynn Resorts Ltd	WYNN	104.0434	107.11	11,144.09		0.93%		27.00%	
Xcel Energy Inc	XEL	624.26956	82.95	51,783.16	0.10%	2.86%	0.00%	8.68%	0.01%
Exxon Mobil Corp	XOM	4156.55942	154.33	641,481.82	1.28%	2.67%	0.03%	9.19%	0.12%
Xylem Inc/NY	XYL	237.69349	118.16	28,085.86	0.06%	1.46%	0.00%	8.50%	0.00%
Block Inc	XYZ	535.37047	70.51	37,748.97					
Yum! Brands Inc	YUM	276.17328	159.65	44,091.06	0.09%	1.88%	0.00%	9.73%	0.01%
Zimmer Biomet Holdings Inc	ZBH	193.56908	82.43	15,955.90	0.03%	1.16%	0.00%	5.64%	0.00%
Zebra Technologies Corp	ZBRA	48.36261	226.26	10,942.52	0.02%			7.00%	0.00%
Zoetis Inc	ZTS	420.64	114.97	48,360.98	0.10%	1.84%	0.00%	7.89%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of April 30, 2026
[5] Bloomberg Professional as of April 30, 2026
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of April 30, 2026
[9] Equals [7] x [8]
[10] Average of Bloomberg Professional and Value Line, as of April 30, 2026
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9112866
R Square	0.8304432
Adjusted R Square	0.8295217
Standard Error	0.0058210
Observations	186

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03054	0.03054	901.18231	0.00000
Residual	184	0.00623	0.00003		
Total	185	0.03677			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0801	0.00	83.74	0.0000	0.0782	0.0819	0.0782	0.0819
U.S. Govt. 30-year Treasury	(0.4275)	0.01	(30.02)	0.0000	(0.4556)	(0.3994)	(0.4556)	(0.3994)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury [7]	Risk Premium [8]	ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.91%	5.91%	10.82%
Blue Chip Near-Term Projected Forecast (Q3 2026 - Q3 2027) [5]	4.82%	5.95%	10.77%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.60%	6.04%	10.64%
AVERAGE			10.74%

Notes:
[1] Regulatory Research Associates, rate cases through April 30, 2026
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of April 30, 2026
[5] Blue Chip Financial Forecasts, Vol. 45, No. 5, May 1, 2026, at 2
[6] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080059 + (-0.427540 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.54%	1.62%	7.92%
2021.1	9.45%	2.07%	7.38%
2021.2	9.55%	2.26%	7.30%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.88%	3.05%	6.83%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.97%
2023.2	10.04%	3.81%	6.23%
2023.3	9.79%	4.23%	5.55%
2023.4	9.82%	4.58%	5.24%
2024.1	9.67%	4.32%	5.35%
2024.2	10.16%	4.58%	5.58%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2024.3	9.86%	4.23%	5.63%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.95%	4.84%	5.11%
2025.3	9.70%	4.85%	4.85%
2025.4	9.91%	4.71%	5.20%
2026.1	9.74%	4.82%	4.93%
2026.2	9.70%	4.91%	4.79%
AVERAGE	11.44%	6.01%	5.44%
MEDIAN	10.86%	5.11%	5.54%

FLOTATION COST ADJUSTMENT -- MONTANA-DAKOTA PROXY GROUP

Company	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
MDU Resources Group	12/4/2025	10,152	$ 19.70	$ 0.6600	$ 300	$ 19.01	$ 7,001	$ 200,000	$ 192,999	3.50%
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
							$ 9,174	$ 253,636	$ 244,462	3.62%

[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9638, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[10] Annualized Dividend	[11] Stock Price	[12] Dividend Yield	[13] Expected Dividend Yield	[14] Expected Dividend Yield Adjusted for Flotation Costs	[15] Value Line Projected EPS Growth Rate	[16] Zacks Projected EPS Growth Rate	[17] S&P Capital IQ Projected EPS Growth Rate	[18] Average Earnings Growth	[19] ROE	[20] ROE Adjusted for Flotation Costs
Alliant Energy Corporation	LNT	2.14	71.31	3.00%	3.11%	3.22%	6.00%	7.20%	8.04%	7.08%	10.19%	10.30%
Ameren Corporation	AEE	3.00	110.76	2.71%	2.82%	2.92%	6.50%	9.30%	8.02%	7.94%	10.76%	10.86%
American Electric Power Company, Inc.	AEP	3.80	132.66	2.86%	2.97%	3.08%	6.50%	6.70%	8.55%	7.25%	10.22%	10.33%
Avista Corporation	AVA	1.97	40.72	4.84%	4.99%	5.17%	5.00%	7.10%	6.23%	6.11%	11.10%	11.28%
CMS Energy Corporation	CMS	2.28	77.02	2.96%	3.07%	3.19%	8.00%	7.10%	7.54%	7.55%	10.62%	10.73%
DTE Energy Company	DTE	4.66	146.55	3.18%	3.28%	3.40%	5.50%	5.90%	7.51%	6.30%	9.58%	9.71%
Duke Energy Corporation	DUK	4.26	129.14	3.30%	3.40%	3.53%	6.00%	n/a	6.58%	6.29%	9.69%	9.82%
Entergy Corporation	ETR	2.56	111.10	2.30%	2.41%	2.50%	3.00%	11.50%	11.91%	8.80%	11.21%	11.30%
Evergy, Inc.	EVRG	2.78	81.62	3.41%	3.55%	3.68%	6.50%	9.10%	8.93%	8.18%	11.72%	11.86%
IDACORP, Inc.	IDA	3.52	143.93	2.45%	2.53%	2.63%	5.00%	7.80%	8.28%	7.03%	9.56%	9.65%
OGE Energy Corporation	OGE	1.70	47.76	3.56%	3.65%	3.79%	3.00%	5.60%	6.57%	5.06%	8.71%	8.84%
Pinnacle West Capital Corporation	PNW	3.64	101.60	3.58%	3.70%	3.84%	6.00%	5.80%	8.12%	6.64%	10.34%	10.48%
PPL Corporation	PPL	1.14	38.42	2.97%	3.08%	3.20%	7.50%	7.50%	7.91%	7.64%	10.72%	10.83%
Southern Company	SO	2.96	95.18	3.11%	3.22%	3.34%	6.50%	7.20%	8.08%	7.26%	10.48%	10.60%
Xcel Energy Inc.	XEL	2.37	79.65	2.98%	3.11%	3.23%	8.00%	9.40%	9.36%	8.92%	12.03%	12.15%
Mean											10.46%	10.58%
Median											10.48%	10.60%
Flotation Cost Adjustment (Mean)										[21]		0.12%
Flotation Cost Adjustment (Median)										[22]		0.12%

Notes:
[1]-[4] Sources: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated December 5, 2025.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Source: Bloomberg Professional
[11] Source: Bloomberg Professional, equals 30-day average as of April 30, 2026.
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Source: Value Line
[16] Source: Zacks
[17] Source: S&P Capital IQ
[18] Equals Average ([15], [16], [17])
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals Average ([20]) − Average ([19])
[22] Equals Median ([20]) − Median ([19])

REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Revenue Stabilization: Overall Revenue Stabilization	[6] Capital Cost Recovery
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	Yes
	Interstate Power & Light Co.	Iowa	Gas	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Historical	No	No	No	No	No
	AEP Texas	Texas	Electric	Historical	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	No
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	Yes
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	Yes
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes
DTE Energy Company	DTE Electric Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes
	DTE Gas Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Duke Energy Carolinas LLC	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes
	Duke Energy Progress LLC	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC	South Carolina	Electric	Historical	No	No	No	No	Yes
	Duke Energy Progress LLC	South Carolina	Electric	Historical	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	No	No	No	No	No
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Entergy Texas Inc.	Texas	Electric	Fully Forecast	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	Yes
OGE Energy Corporation	Oklahoma Gas and Electric Company	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes
	Oklahoma Gas and Electric Company	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Yes	No	No	Yes	Yes
PPL Corporation	Kentucky Utilities Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	PPL Electric Utilities Corp.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	Narragansett Electric Co.	Rhode Island	Electric	Historical	Yes	No	No	Yes	Yes
	Narragansett Electric Co.	Rhode Island	Gas	Historical	Yes	No	No	Yes	Yes
	Kentucky Utilities Co.	Virginia	Electric	Historical	No	No	No	No	No
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	No	No	No	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	Yes	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	Yes	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Proxy Group Totals									
			Fully Forecast	36					
			Partially Forecast	8				Yes 57	67
			Historical	39				No 26	16
			% Forecast	53.01%				% Yes 68.67%	80.72%
Montana-Dakota Utilities Co. [7]		North Dakota	Electric	Fully Forecast	No	No	No	No	Yes

Notes:
[1] Regulatory Research Associates, effective as of April 30, 2026.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September, 2025. Operating subsidiaries not covered in this report were excluded from this exhibit. Designated "Yes" if full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025. Designated "Yes" if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".
[7] Data provided by the Company.

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2024 Q1 - 2025 Q4)				
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-Term Debt Ratio	Total Capitalization
Alliant Energy Corporation	LNT	51.49%	47.65%	0.00%	0.86%	100.00%
Ameren Corporation	AEE	52.26%	45.46%	0.44%	1.83%	100.00%
American Electric Power Company, Inc.	AEP	48.47%	50.19%	0.00%	1.34%	100.00%
Avista Corporation	AVA	47.57%	47.35%	0.00%	5.09%	100.00%
CMS Energy Corporation	CMS	47.91%	51.23%	0.16%	0.70%	100.00%
DTE Energy Company	DTE	48.01%	49.08%	0.00%	2.91%	100.00%
Duke Energy Corporation	DUK	52.39%	46.36%	0.00%	1.26%	100.00%
Entergy Corporation	ETR	50.73%	49.18%	0.09%	0.00%	100.00%
Evergy, Inc.	EVRG	57.17%	38.24%	0.00%	4.58%	100.00%
IDACORP, Inc.	IDA	49.12%	50.88%	0.00%	0.00%	100.00%
OGE Energy Corporation	OGE	52.80%	46.29%	0.00%	0.91%	100.00%
Pinnacle West Capital Corporation	PNW	49.92%	46.43%	0.00%	3.64%	100.00%
PPL Corporation	PPL	55.54%	43.43%	0.00%	1.03%	100.00%
Southern Company	SO	55.08%	44.19%	0.00%	0.72%	100.00%
Xcel Energy Inc.	XEL	53.54%	45.82%	0.00%	0.64%	100.00%
Average		51.47%	46.79%	0.05%	1.70%	
Median		51.49%	46.43%	0.00%	1.03%	
Maximum		57.17%	51.23%	0.44%	5.09%	
Minimum		47.57%	38.24%	0.00%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of the operating subsidiaries.
[2] Operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony

Of

Robert Frank

Q. Please state your name and business address.

A. My name is Robert Frank, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am employed by Montana-Dakota Utilities Co. (Montana-Dakota or Company) as the Director of Electric Transmission Engineering.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have leadership responsibility for the engineering, design, construction, and maintenance of Montana-Dakota's electric transmission and substation facilities, including property and right-of-way acquisitions of the Company.

Q. Please outline your educational and professional background.

A. I received my Bachelor of Science degree in Electrical Engineering from North Dakota State University in 2002. I received my Master of Business Administration from the University of Mary in 2008. In 2015, I attended the Utility Executive Course at the University of Idaho. I am a registered Professional Engineer in the State of North Dakota.

I began my career at Montana-Dakota in 2004 as a system protection engineer in the Electric Transmission Engineering Department. Throughout the next ten years, I worked on various substation and transmission projects gaining experience in engineering design, project management, construction management, and real estate transactions. In 2014, I accepted my current position.

Prior to joining Montana-Dakota, I worked for an industrial contractor as a field engineer providing engineering support to construction crews and performing project management duties.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming and the Public Utilities Commission of South Dakota.

Q. What is the purpose of your testimony?

A. My testimony supports the Company's request for rate recovery associated with transmission and substation capital investments by describing the scope, purpose, and necessity of those investments. These investments are necessary to maintain system reliability and support load growth and are included in the Company's proposed rate base in this proceeding.

Q. How does the Company identify and prioritize transmission and substation capital projects?

A. Capital projects are identified through system planning studies, inspection and testing results, and load growth. Montana-Dakota's system planning engineers conduct annual system performance studies that include N-1 contingency analysis, which is a reliability assessment used to ensure the power system can withstand the loss of any single component without causing widespread disruption. These studies identify areas of the system that require upgrades to reliably serve existing and forecasted customer load under a range of operating conditions. The Company incorporates the identified upgrades into its work plan and prioritizes them based on system needs, including current reliability requirements and expected future conditions. In addition to these studies, routine inspections, maintenance activities, and equipment testing also identify system deterioration and potential equipment failure. These needs are also incorporated into the work plan and prioritized based on acceptable performance tolerances and operating experience with similar equipment and systems.

Capital projects may also be initiated in response to requests from third parties seeking interconnection to the transmission system. The priority of these projects is generally determined by the schedule of the interconnecting party.

Q. Would you please describe the major capital projects that are currently underway?

A. Yes. I will provide a description of each project and why it is needed.

<u>Stanley Substation</u>

Q. Please describe the new Stanley Substation project.

A. The new 115/69 kilovolt (kV) Stanley Substation project will replace the existing Stanley Substation near Stanley, North Dakota, which is being retired due to age and condition. The new Stanley Substation is being constructed on a greenfield site and will include new foundations, substation equipment, control systems, an equipment enclosure, and associated materials. Construction of new 115 kV and 69 kV transmission line segments is required to terminate the existing lines into the new Stanley Substation.

Q. Why did Montana-Dakota initiate this project?

A. Montana-Dakota's inspection, maintenance, and testing programs identified significant deterioration in the control systems, power transformer, voltage regulator, and circuit breakers. In response, the Company performed a comprehensive review of the protection system components and other outdoor substation equipment. The review determined that most of the protection and control components are obsolete; cables and other material have deteriorated and are failing, and the outdoor substation equipment requires extensive maintenance and repair. Given the age of the facility, which was constructed in 1969, the Company determined that replacement of the entire substation is necessary.

Q. What is the project timeline?

A. Project design was initiated in 2024, construction began in the fall of 2025, and project completion is scheduled for December 2026.

Q. How will Montana-Dakota customers benefit from the project?

A. Montana-Dakota customers will experience improved system reliability as a result of the new Stanley Substation. The existing Stanley Substation is currently configured as a tap on the 115 kV transmission line between the Tioga and Kenmare substations. Under this configuration, a fault on the 115 kV line results in an outage to all customers served from the Stanley Substation.

The new Stanley Substation will be constructed using a ring bus design, which separates the 115 kV line into two independent line sections. With this configuration, a fault on one line section will not interrupt service to Stanley customers, as the remaining line section will continue to serve load. The design significantly reduces customer exposure to transmission line faults and enhances overall system reliability.

In addition, the installation of new substation equipment incorporating modern materials, technology, and design standards will further improve system reliability and resiliency.

Q. How is the project allocated?

A. The 115 kV section of the Stanley Substation is allocated to Montana-Dakota's integrated transmission system, while the 69 kV section is allocated to North Dakota customers directly. The corresponding transmission lines are allocated to the integrated transmission system.

Q. Describe any alternatives considered to address the identified issues.

A. As an alternative to a complete substation rebuild, the Company evaluated replacing only those components that are not repairable. While this approach may defer some costs in the near term, it would require ongoing construction at this facility and result in higher long-term costs due to the continued need to replace aging equipment and materials. In addition, ongoing operation and maintenance costs would be significant due to the condition of the existing infrastructure. This alternative is estimated to cost significantly more than building the new Stanley Substation.

Q. What are the costs of the project?

A. The costs of the project are as follows:

- Stanley Substation - $7,159,959 as included in FP-324740 on Statement B, Schedule B-2, page 3.
- Transmission line reroutes - $216,658 and $919,746 as included in FP-326903 and FP-326877, respectively, on Statement B, Schedule B-2, pages 3 and 10.

<u>Install Lignite–Kincaid 60kV transmission line</u>

Q. Please describe the Lignite–Kincaid 60 kV transmission line project.

A. The Lignite-Kincaid 60 kV transmission line project involves constructing a new 60 kV transmission line that connects the existing Lignite Transmission Substation, near Lignite, North Dakota, to the existing transmission system at the Kincaid Transmission Substation, near Columbus, North Dakota. Upon completion, the line will become part of Montana-Dakota's transmission system serving customers in the Lignite to Crosby and Lignite to Tioga areas.

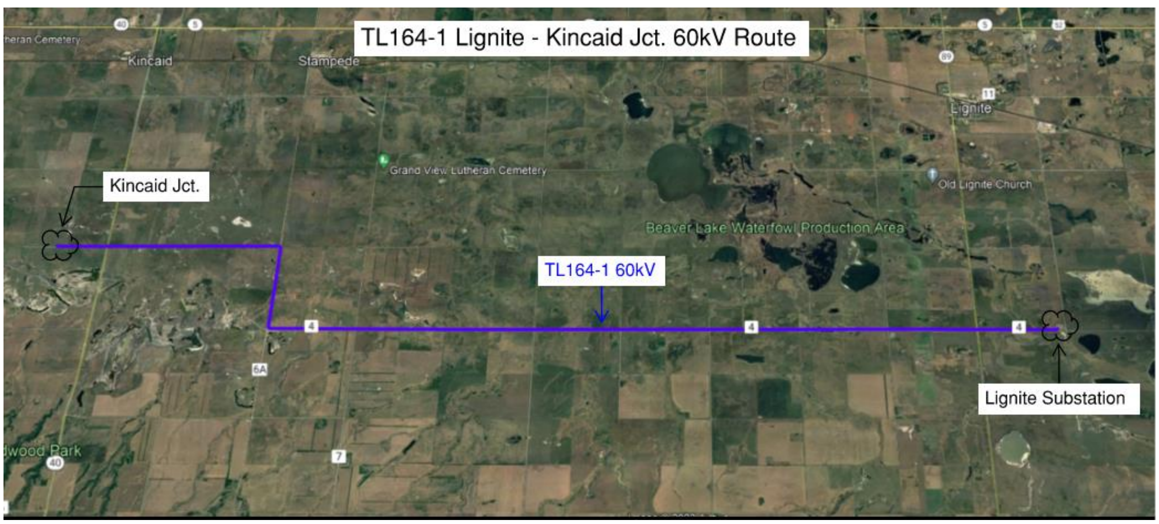


Figure 1 – Lignite-Kincaid 60 kV Line Route

Q. Why did Montana-Dakota initiate this project?

A. Montana-Dakota initiated this project due to the deteriorating condition of the existing Kincaid Transmission Substation, which has reached the point where replacement is necessary. The substation was originally constructed to connect the Kincaid Power Station which was retired in the 1960s. Today, the substation operates as a 60 kV switching substation connecting transmission lines from Crosby, Lignite, and Tioga. The project will improve system configuration by directly connecting Lignite to Crosby, bypassing Kincaid, while the existing Lignite-Kincaid 60 kV transmission line will be utilized to maintain the connection between Lignite and Tioga. As a result of this project, the Kincaid Transmission Substation is no longer needed and will be retired without replacement.

Q. What is the project timeline?

A. Project design began in 2025, construction is scheduled to begin in the fall of 2026, and the project is expected to be completed in March 2027.

Q. How will Montana-Dakota customers benefit from the project?

A. The project will provide several key benefits to Montana-Dakota customers. It will improve system reliability by eliminating the existing three-terminal transmission line configuration, which helps reduce the frequency and duration of outages. Under the current configuration, line faults are difficult to detect and isolate quickly due to the limitations in the protection and control systems, resulting in increased outage exposure and longer restoration times. The project will also incorporate updated transmission line design standards for the new Lignite-Kincaid line, including the use of horizontal post insulators with a pole top shield wire, replacing older construction that utilized crossarms without a shield wire. Using horizontal post insulators instead of crossarms provides a hardened design that helps reduce wildfire risk. In addition, the project will increase system capacity, supporting future growth and development in the area.

Q. How is the project allocated?

A. The Lignite-Kincaid 60 kV transmission project is allocated to North Dakota customers directly and is not a part of the integrated transmission system. The existing Kincaid Substation was directly assigned to North Dakota customers as well.

Q. Describe any alternatives considered to address the identified issues.

A. Replacement of the Kincaid Transmission Substation was considered as an alternative; however, this option was not pursued due to the operational limitations associated with maintaining a three-terminal line switching substation. The Lignite Transmission Substation, constructed in 2014, provided the opportunity for the Company to pursue the proposed project, which provides greater overall system benefits.

Q. What are the costs of the project?

A. The cost of the project is as follows:

- Transmission line build - $7,731,195 as shown as FP-307500 on Statement B, Schedule B-2, page 10.

<u>Merricourt Transmission Substation</u>

Q. Please describe the Merricourt Transmission Substation project.

A. Montana-Dakota is constructing an addition to the existing Merricourt Transmission Substation near Ashley, North Dakota. The addition includes installing a 230 kV shunt reactor, 230 kV circuit breakers, a 230/41.6 kV power transformer, a 41.6 kV ring bus addition with three 41.6 kV circuit breakers, and all associated equipment and material. The Company originally constructed the Merricourt Transmission Substation to interconnect the Merricourt wind facility to Montana-Dakota's 230 kV transmission system.

Q. Why did Montana-Dakota initiate this project?

A. Montana-Dakota initiated this project based on findings from transmission system stability studies conducted by its system planning engineers, which showed that voltage levels on the 230 kV transmission system routinely exceed normal operating limits during low wind conditions and when line sections are de-energized. Installation of a shunt reactor will absorb reactive power and reduce voltage, supporting reliable and efficient system operations under a range of operating conditions.

In addition, the existing 41.6 kV transmission system cannot carry the area load when operated from a single source. For example, if a line section is opened near Wishek, the remaining energized line cannot serve load from Ellendale. This limits operational flexibility and demonstrates the need for an additional power source between Wishek and Ellendale.

The Merricourt Transmission Substation is ideally located approximately midway between the Wishek and Ellendale substations, allowing it to serve as an additional source of supply for the area. Installation of a 230/41.6 kV power transformer and a 41.6 kV ring bus at Merricourt will divide the existing 41.6 kV circuits and provide a third source to improve system reliability.

Q. What is the project timeline?

A. Project design was initiated in 2024, construction began in 2025, and project completion is scheduled for the end of 2027.

Q. How will Montana-Dakota customers benefit from the project?

A. The shunt reactor is needed to absorb excess reactive power that the transmission system generates during periods of light loading, which can result in elevated transmission voltages. The reactors maintain system voltages within established operating limits, improve system reliability, and support the safe operation of the transmission grid.

The addition of the power transformer and 41.6 kV ring bus provides a third power source to the existing transmission system, improving reliability to customers in the towns of Ashley, Lehr, Fredonia, Kulm, Merricourt, Monango, and the surrounding areas. The Merricourt Transmission Substation reconfigures the existing system into separate sections, reducing customer exposure to transmission line faults and enhancing overall system reliability.

Q. How is the project allocated?

A. The 230 kV additions and a portion of the 230/41.6 kV power transformer are allocated to Montana-Dakota's integrated transmission system, and the 41.6 kV ring bus is allocated to North Dakota customers directly.

Q. Describe any alternatives considered to address the identified issues.

A. The Company evaluated alternatives to the installation of a shunt reactor, including operational adjustments and system reconfiguration. However, unlike increased system loading, which can naturally absorb reactive power, these alternatives do not provide the same level of continuous and predictable voltage control. Shunt reactors represent the most practical and reliable solution for addressing persistent high-voltage conditions when sufficient system load is not present.

The Company also considered open-air reactor designs but determined they were not suitable for North Dakota's extreme weather conditions, larger space requirements, and increased maintenance considerations. The 230 kV transmission system is the only source of additional power to this area beyond the existing 41.6 kV transmission system. The alternative to using the 230 kV source at Merricourt is to upgrade the existing 41.6 kV transmission system or convert the 41.6 kV transmission system to a higher voltage, such as 69 kV. The cost of upgrading the transmission system between Wishek and Ellendale is significantly more expensive than this project.

Q. What are the costs of the project?

A. The costs of the project are as follows:

- Add Reactor – Merricourt Substation:
  - 2026: $2,700,796 as included in FP-326847 on Statement B, Schedule B-2, page 3.

    - 2027: $517,475 as included in FP-326847 on Statement B, Schedule B-2, page 10.
- Add Transformer – Merricourt Substation - $4,174,599 as included in FP-316202 on Statement B, Schedule B-2, page 3.
- Add Ring Bus – Merricourt Substation- $2,540,856 as included in FP-326843 on Statement B, Schedule B-2, page 10.

Q. In addition to reliability and operational benefits, are there other benefits associated with these projects?

A. Yes. In addition to improving reliability and operational flexibility, transmission investments of this nature may provide additional system-level benefits under applicable regional transmission organization tariff provisions, including potential eligibility for regional cost recovery mechanisms or transmission-related credits. While such benefits are not the primary driver of these projects, they may help offset overall system costs and provide incremental value to customers over time.

The projects discussed in my testimony, along with several other projects in this case, have been approved through the Midcontinent Independent System Operator, Inc. (MISO) Transmission Expansion Plan (MTEP), as shown in Table 1. In addition, two of the projects have been approved for Southwest Power Pool, Inc. (SPP) Section 30.9 credits, as shown in Table 2. These approvals provide regional transmission benefits and help offset transmission tariff charges which are returned to customers through the Transmission Cost Adjustment Rate 59.

Table 1 - MISO Transmission Expansion Plan (MTEP) Approved Projects

2026		Project ID	Facility ID
FP-324742	Purchase Land - Elgin Substation	50260	50458
FP-326269	Purchase Land - Hettinger Substation	50260	50455
FP-316202	Add Bay & Breaker Ring - Merricourt Substation	15747	23760
FP-324740	Build New Stanley Substation	13869	22936
FP-326847	Add Reactor - Merricourt Substation	25475	28712

2027		Project ID	Facility ID
FP-326843	Add Ring Bus - Merricourt Substation	15747	23760
FP-326847	Add Reactor - Merricourt Substation	25475	28712
FP-321704	Replace Glendive River Crossing	51075	51972 & 51972
FP-307500	Install Line - Lignite-Kincaid	15780	23791 & 23792

Table 2 - SPP Section 30.9 Credit Projects

2026

FP-324740 Build New Stanley Substation

2027

FP-307500 Install Line - Lignite to Kincaid 60 kV Line

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26___

Direct Testimony

Of

Brian Giggee

Q. Please state your name and business address.

A. My name is Brian Giggee and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Director of Electric System Operations and Planning for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I am responsible for the oversight and management of the day-to-day operations of the Company's electric control center, as well as its system operations and planning and communication engineering departments.

Q. Please outline your educational and professional background.

A. I hold a Bachelor of Science degree in Electrical Engineering from the South Dakota School of Mines and Technology and have been employed by Montana-Dakota for more than eighteen years, including the past year managing the system operations and planning department.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports the Company's projected electric sales and demand used in developing the revenue requirement and provides support for the inclusion of the mobile radio system replacement project in rate base.

<u>Electric Load Forecast</u>

Q. What is the result of Montana-Dakota's latest customer long-term electric load forecast?

A. Montana-Dakota completes an update to its long-term electric load forecast every year with the 2026-2045 forecast completed on December 31, 2025. The long-term electric load forecast is a twenty-year forecast that shows annual customer electric sales volumes along with a forecast of annual summer and winter customer peak demand.

The Company develops electric sales forecasts separately for Montana, North Dakota, and South Dakota for the following customer classes: residential, small commercial and industrial, large commercial and industrial, street lighting and miscellaneous. The state-specific forecasts are then combined to produce a total Integrated System sales forecast. Summer and winter peak demand forecasts are developed on an Integrated System basis and then allocated back to the states.

Q. What were the results of the 2026-2045 sales forecast?

A. The total Integrated System sales in the new forecast are projected to grow at a five-year average rate of 0.28% per year from 2026-2031, an improvement to the five-year historic average growth rate of -0.05% from 2020-2025. North Dakota's electric sales over a five-year period are projected to increase at 0.33% per year for 2026-2031 compared to a historic five-year period growth rate of 0.46% per year from 2020-2025.

The Integrated System summer peak is forecasted to increase at 0.30% per year, while the winter peak is forecasted to grow at 0.39% per year over the twenty-year period. Based on this forecast, it is anticipated Montana-Dakota will remain a summer peaking electric utility.

The five-year projected average sales forecast and five-year historic growth rate for North Dakota electric customers by rate class are:

Customer Class	Projected Five-Year Average Sales Growth Rate	Historic Five-Year Average Sales Growth Rate
Residential	0.33%	0.31%
Small C&I	0.67%	1.21%
Large C&I	0.07%	0.15%
Street Lighting	0.00%	-2.32%
Miscellaneous	0.00%	-0.32%

The projections are used as the basis for the billing determinants used to develop the Company's revenue requirement.

Q. Why are large loads, such as data centers, excluded from Montana-Dakota's long-term electric load forecast?

A. Montana-Dakota has a High Density Contracted Demand Response Rate 45 tariff in North Dakota and South Dakota available to data center customers with loads greater than 10 MW and subject to an electric service agreement.

Rate 45 customers are excluded from the long-term electric forecast, as their loads are not supplied by Montana-Dakota's rate base generation fleet. These load requirements are instead met through purchases on the Midcontinent Independent System Operator (MISO) electric market and/or specific supply arrangements.

<u>Mobile Radio System Replacement Project</u>

Q. Can you describe the Company's existing mobile radio system?

A. Montana-Dakota and its division, Great Plains Natural Gas Co. operate a two-way radio system that serves utility operations across portions of five states. The Company constructed the current system in the 1970s and 1980s. It consists of 70 radio towers, 350 mobile units, 20 office base consoles, and 30 remote handheld units. The system is now obsolete and depends on telephone interconnects to link repeater towers, requiring users to manually key or dial codes and telephone numbers to communicate between coverage areas.

Q. Why is replacement of the Company's existing mobile radio system necessary?

A. Replacement of the existing mobile radio system is necessary because the current system creates operational inefficiencies and increases risk during emergency conditions. Reliable communication is critical during emergencies to support the continued safe and reliable delivery of electric service.

Q. What type of replacement is the Company implementing for its mobile radio system?

A. The Company is installing a new trunked 450 MHz radio system which allows users to move throughout the Company's service territory and communicate with other employees without relying on telephone interconnect equipment. The new system will improve communication reliability, enhance emergency response capabilities, and support efficient system operations across the Company's service territory.

Q. What alternatives did the Company consider in evaluating the need to replace its mobile radio system?

A. The alternative options that Company considered are:

1. Updating the existing mobile radio system; and
2. Utilizing prioritized cellular communications like AT&T's First Net system.

Updating the Company's existing mobile radio system would continue to rely on existing radio frequencies, newer repeater equipment, and telephone interconnects. This configuration is difficult for employees to use and does not support movement throughout the Company's service territory, which reduces its effectiveness during normal operations. The Company further believes this option would be less effective during emergency conditions because communications would remain constrained by access to area repeater sites and the fixed coverage area of individual repeater towers.

Cellular options such as AT&T's First Net rely on commercial cellular towers and networks, which may become overloaded during emergencies. In these situations, 911 operators can direct AT&T First Net to remove non-emergency personnel, including Montana-Dakota, from its prioritized network, potentially leaving Montana-Dakota in a situation where employees cannot communicate during emergencies. Furthermore, cellular towers currently provide less coverage than two-way radio systems. That limited coverage creates communication issues across the Company's service territories, especially in rural areas.

Q. What is expected cost of the mobile radio system project?

A. The cost of the mobile radio system project is $11,582,297 and will be placed in service in 2027 as shown in FP-316490 and FP-316128 on Statement B, Schedule B-2, page 11 and 12.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26___

Direct Testimony

Of

Daryl Anderson

Q. Please state your name and business address.

A. My name is Daryl Anderson and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Director of Electric Distribution Services for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. My responsibilities include oversight and management of the electric distribution operations and engineering support services, including electric operations systems, metering, electric engineering systems, electric engineering project construction & maintenance, and electric distribution standards and procedures.

Q. Please outline your educational and professional background.

A. I hold an Associates of Science Degree in Engineering from Minot

State College and a Bachelor of Science in Electrical and Electronics Engineering from North Dakota State University. My work experience at Montana-Dakota includes six years as an Electrical Engineer working at various District locations, twelve years working as the Electric Superintendent in the Rocky Mountain Region, and seven years as the Director of Distribution Engineering with both gas and electric utility responsibilities. I assumed my current position in 2015. Prior to my work at Montana-Dakota I worked for five and a half years as an Electric Engineer for a combination gas and electric utility located in Iowa.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Wyoming and Montana and the South Dakota Public Utilities Commission.

Q. What is the purpose of your testimony?

A. My testimony supports the Company's request to include electric distribution system upgrades (EDS), including wildfire mitigation investments, in rate base by describing the scope, purpose, and necessity of these projects.

Q. Please briefly describe what type of wildfire mitigation upgrades are being done.

A. Montana-Dakota filed its North Dakota Wildfire Mitigation Plan in Case No. PU-25-301 and continues to implement and refine that plan as part of its electric operations. As part of the plan, the Company is undertaking targeted EDS projects intended to help reduce the risk that electric facilities could contribute to wildfire ignition. These efforts focus on two primary areas:

1. Operational changes based on situational awareness of current weather and fire hazard conditions intended to reduce wildfire risks.
2. EDS hardening of the existing electric distribution lines through assessment and mitigation of conditions that could contribute to wildfire-related risk.

Q. What is meant by operational changes based on situational awareness?

Montana-Dakota's system operations group tracks weather-related warnings such as Red-Flag warnings and Fire Hazard Index information and adjusts daily operations to help reduce wildfire risk. Based on situational weather conditions and wildfire risk information, Montana-

Dakota is working to establish an Enhanced Protection Safety Settings (EPSS) program that allows real-time modifications of electric distribution circuit protection equipment to help reduce the risks of fire ignition during system events. The modified settings may include elimination of automated reclosing operations or a reduction in total fault energy, should a fault occur.

Q. What is distribution system hardening?

A. Distribution system hardening is a term used for performing assessments and mitigation of existing distribution lines aimed at reducing the likelihood that EDS equipment could initiate a fire. The process for system hardening includes assessing each line section within the wildfire risk areas and implementing mitigation measures. Mitigation may include:

1. Undergrounding existing overhead line section: or
2. Modifying existing overhead lines by eliminating obsolete equipment and updating line sections to current construction standards.

By assessing and mitigating the existing electric distribution lines in higher fire risk areas, Montana-Dakota seeks to reduce wildfire risk and improve avian safety for eagles and large raptor birds.

Q. How does the Company determine whether to underground or modify existing overhead lines?

A. The Company considers several factors for each existing line section, including expected future load growth, the age and condition of the line, existing engineering design, emergency access for maintenance and patrol, vegetation-related risk, and the overall cost of each mitigation option. The Company evaluates these factors to determine which option provides the most effective wildfire mitigation while maintaining reliable and cost-effective service.

Q. What are the benefits of these operations changes and system upgrades?

A. The operations changes and system upgrades are reasonable and prudent and have been designed to help reduce the risk that the electric distribution system may contribute to a wildfire event. In doing so, the projects are intended to improve the overall safety of the public and Montana-Dakota employees. The upgrades also enhance system reliability by reducing the likelihood of faults occurring on the distribution system. Additionally, undergrounding and overhead distribution structure mitigation improvements increase avian and other animal safety around distribution structures. These improvements include new insulated materials and improved avian voltage spacing on remaining overhead structures and equipment. As discussed in the testimony of Ms. Kivisto, these investments are part of the Company's broader strategy to maintain and enhance electric system reliability and safety.

Q. What is the cost of the Wildfire Distribution Upgrades?

A. For the above stated reasons, the Company's requested capital costs reflect the EDS upgrades described earlier in my testimony, including operational enhancements and system hardening measures intended to prudently mitigate the risk of electric facilities contributing to wildfire ignition. The total costs are $2,144,905 for 2026 and $2,661,698 for 2027, as shown in FP-326500 on Statement B, Schedule B-2, page 4 and 10.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony

Of

Bradley J. Davison

Q. Please state your name and business address.

A. My name is Bradley J. Davison and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota or Company).

Q. Please describe your duties as Regulatory Affairs Manager.

A. I am responsible for the overall management of the general rate case filing process for each of the jurisdictions in which Montana-Dakota operates, including the preparation of gas and electric cost of service studies and the associated projected operating income, rate base, and rate of return, and the additional revenue requirement for each distinct jurisdiction.

Q. **Please describe your education and professional background.**

A. I graduated from North Dakota State University with a Bachelor of Science degree in Hospitality and Tourism Management, and University of Mary with a Bachelor of Science degree in Accounting. I started my career with Montana-Dakota in 2011 as a Credit and Collections Team Lead. During my tenure with the Company, I have held various positions of increasing responsibilities including Credit and Collections Supervisor, Revenue Accounting Manager, and now as Regulatory Affairs Manager.

Q. **Have you testified in other proceedings before regulatory bodies?**

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming and the Public Utilities Commission of South Dakota.

Q. **Are you familiar with the books and records of Montana-Dakota and the manner in which they are kept?**

A. Yes. Montana-Dakota's books and records are kept in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the North Dakota electric operations per books cost of service for the twelve months ended December 31, 2025, and the projected cost of service for 2026 and 2027. Based on the results, I have prepared the calculation of the revenue deficiency. Separately, I have calculated the interim request. Specifically, I will:

- Provide an overview of the Company's revenue requirement, including how it was developed and the treatment of key components reflected in this filing, including the Renewable Rider, Generation Rider, Transmission Rider, and High Density Contracted Demand Rate 45 tariff;
- Describe the development of projected revenues and expenses, including key Operation and Maintenance expenses such as labor and benefits;
- Describe the calculation of depreciation expense, including the application of approved and proposed depreciation rates, decommissioning-related amortization, and the implementation of FERC Order No. 898;

- Describe the calculation of taxes, including local, state, and federal taxes. This section includes the computation of property, payroll and production taxes as well as other miscellaneous taxes included in the projected cost of service;
- Present the development of projected rate base, including plant in service, accumulated depreciation, working capital, and accumulated deferred income tax balances;
- Describe significant plant additions and changes reflected in the test period, including those discussed below, specifically the new Mobridge District Office and Warehouse, Training Center, and the retirement of Glen Ullin Station 6;
- Present the Company's analysis of the E8760 alternative energy allocation methodology;
- Present the interim revenue requirement, including the adjustments made to reflect the currently authorized return on equity and other applicable modifications.

Each of the items above supports the proposed revenue requirement and reflects necessity of investments in system reliability, safety, and regulatory compliance, while maintaining cost causation and protecting general customers from costs associated with large-load customers taking service under Rate 45.

Q. What statements, schedules, and exhibits are you sponsoring?

A. I am sponsoring the following statements and exhibits which provide detailed support for the revenue requirement presented in my testimony:

- Statements A through D, Statement F and Statements F-2 through J, and the revenue requirement presented in Exhibit No.___(BJD-1).
- Interim Statements A through D, Interim Statement F and Interim Statements F-2 through J, the interim revenue requirement presented in Exhibit No.___(BJD-2).
- Common Depreciation Study performed by Concentric Advisors, ULC presented in Exhibit No.___(BJD-3).
- E8760 alternative energy allocation analysis for fuel and purchased power presented in Exhibit No.___(BJD-4).

Q. Were these statements and exhibits prepared by you or under your direct supervision?

A. Yes, they were.

Revenue Requirement

Q. What is the amount of the revenue increase requested in the case?

A. The Company is requesting an overall net revenue increase of $34,494,537, or 14.5 percent, based on a projected 2027 test year. This overall net increase includes the transition of the transmission plant investments from the Transmission Rider to base rates, as shown in Table 1 below.

Table 1: Net Revenue Requirement

Base Rate Revenue Increase	$43,220,844	18.1%
Transmission Rider Decrease	(8,726,307)	(3.6%)
Net Change	$34,494,537	14.5%

The increase in the revenue requirement is necessary to recover the cost of providing safe and reliable electric service, including continued investment in transmission, distribution, general plant, and other utility infrastructure, as well as changes in operating costs needed to serve customers.

Q. You have touched on riders and Rate 45. Please explain their impact to the Revenue Requirement.

In developing the revenue requirement for this filing, Montana-Dakota made targeted adjustments to ensure proper cost assignment and alignment with regulatory recovery mechanisms. Specifically:

- Costs and revenues associated with large-load customers served under Rate 45 have been excluded;
- Costs and revenues associated with the Renewable Resource Cost Adjustment (Renewable Rider) and the Generation Resource Recovery Rider (Generation Rider) have been excluded;
- The Environmental Cost Recovery Rider is not currently in use and therefore no adjustments were necessary; and
- The Company transferred plant in service previously authorized for recovery in the Transmission Cost Adjustment (Transmission Rider) to base rates. Transmission-related expenses and revenues will remain in the Transmission Rider for future recovery.

The Company began with the 2025 per books results of operations and removed the Renewable Rider, Generation Rider, Rate 45, and the revenues and expenses that will remain in the Transmission Rider. These adjustments established the Adjusted 2025 amount that will be referenced throughout this testimony.

These adjustments maintain consistency with prior Commission treatment while improving the alignment between cost responsibility and rate recovery and are described in greater detail below.

Q. Please describe and compare 'traditional' retail customers and Rate 45 customers. In addition, provide clarification of the Company's treatment of Rate 45 revenue and costs in this filing.

A. Montana-Dakota is a vertically integrated electric utility, and the traditional retail customer takes a bundled service that includes components of generation, transmission and distribution service. The Company's revenue requirement is designed to match the total cost of service for all customers with an allocation of that cost for each customer class.

In contrast, Montana-Dakota's current Rate 45 customers take only the transmission service component. Rate 45 customers are not connected to the distribution system and cannot rely on the Company's generation fleet for capacity and energy needs. Furthermore, all customers served under Rate 45 take service through a Commission-approved Electric Service Agreement (ESA). Each ESA is tailored to the facts and circumstances for that individual customer and situation and includes appropriate recovery related to the transmission service the customer is taking. Lastly, the Company's current ESAs have special provisions regarding the treatment of the revenue received, the level of investment and associated responsibility of the related funding.

Therefore, the Company has excluded costs and revenues associated with these large-load customers served under Rate 45 to ensure that the revenue requirement in this case accurately reflects the costs and revenues associated with serving traditional retail customers.

Q. How does the Company treat plant and infrastructure associated with data center customers?

A. The Company does not include rate base associated with data center infrastructure in this filing. The facilities required to serve these customers are either directly assigned to the customer or otherwise funded by the data center, ensuring that these investments are not recovered from general customers.

Q. How are fuel and purchased power costs for data center customers treated?

A. Fuel and purchased power costs associated with data center customers are treated as a pass-through; however, they are not intermingled with traditional customers' fuel and purchased power costs. These customers are responsible for the purchase of their power needs through the MISO market, and as such, those costs are not included in the revenue requirement used to establish base rates in this proceeding.

Q. Do data center customers provide any benefit to general customers?

A. Yes. The Company has a Commission-approved arrangement where a percentage of the margins associated with these customers are returned to general customers through the Fuel and Purchased Power Adjustment. In addition, transmission-related revenues are credited to customers through the Transmission Rider.

Q. What is the overall effect of excluding Rate 45 from this filing?

A. Excluding Rate 45 ensures that the revenue requirement reflects only the costs and revenues associated with serving general customers, while maintaining appropriate cost causation and avoiding cross-subsidization between customer classes. The Company has taken steps to remove costs and revenues associated with data center customers from this filing. To the extent an incidental cost has not been removed, the Company asserts these minor costs have been more than offset by the benefits customers receive through the margin sharing mechanism.

Q. Please describe how the Company is proposing to treat the Transmission Rider in this filing.

A. In this filing, the Company proposes to transfer the December 31, 2025 plant in service balance of approximately $81.2 million currently included in the Transmission Rider rate base into the Revenue

Requirement to be recovered in base rates going forward. The Transmission Rider will continue to recover ongoing transmission-related revenues and expenses, including those associated with MISO and SPP transmission activity, as well as Rate 45 transmission revenues.

The Company's proposed treatment is similar to the approach approved in Case No. PU-22-194, where certain Generation Rider-related investments were moved to base rates while the rider mechanism continued to function for ongoing cost recovery and true-up.

To reflect this change, the Company will adjust base rates through rate design to incorporate the revenue requirement associated with the transferred transmission investment, while maintaining the Transmission Rider for future recoveries consistent with its existing structure.

Q. What is the customer impact associated with transferring the Transmission Rider components to base rates?

A. The proposed transfer of Transmission Rider components to base rates will result in a corresponding decrease in Transmission Rider rates and an offsetting increase in base rates. This reallocation does not, in and of itself, change the overall revenue requirement, but rather shifts the recovery of these costs from a rider mechanism to base rates.

Q. Why are the Renewable and Generation Riders excluded from this case?

A. Montana-Dakota has implemented a levelized recognition of the Production Tax Credits (PTCs) for Thunder Spirit Wind in Case No. PU-20-440, the Diamond Willow Wind Phase 1 repower project in Case No. PU-21-420, and Badger Wind in Case No. PU-25-75. Under this methodology, customer impacts of PTCs are spread over the life of the respective wind facilities rather than being recognized solely in the periods in which they are earned. To maintain transparency and consistency with this treatment, the Company is not proposing any changes to the Renewable Rider in this case.

This non-traditional rate making approach does not comport to the calculation of the revenue requirement for base rates used in this proceeding and it would not be appropriate to include the Renewable Rider.

No changes to the Generation Rider revenue requirement are proposed in this filing. The Company believes it is appropriate to continue recovering the regulatory assets established upon the closure of Lewis & Clark Unit I and Heskett Units I and II through the Generation Rider, which is trued-up annually and allows timely rate adjustments once amortization is complete.

Q. How was the $34,494,537 revenue requirement increase derived?

A. The projected revenue requirement for the 2027 test period was developed using projected sales revenues, O&M expenses, other operating expenses, taxes, and rate base. Projected sales revenues include $8,726,307 associated with transmission plant currently being recovered through the Transmission Rider. The development of these components is discussed in greater detail in the following sections.

Q. What were the results of North Dakota electric operations for 2025?

A. Statement A, pages 2 and 3 show the per books income statement and rate base for the North Dakota electric operations for 2025. As shown on page 2, North Dakota electric operations produced a return on rate base of 5.813 percent for the twelve months ended December 31, 2025. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the referenced Statements.

Q. How do the Per Books, Adjusted, and Projected results relate to each other?

A. The Per Books 2025 results reflect actual historic performance. The Adjusted 2025 reflects the removal of rider-related costs and Rate 45 as discussed above, to provide a comparable baseline to the projected periods. The projected 2026 and 2027 results then build on this adjusted baseline to reflect expected future operations. Any mention of removing riders and Rate 45 will be referred to as “Adjusted 2025”.

Q. How was the per books cost of service allocated to North Dakota?

A. The Company uses a jurisdictional accounting system that directly assigns or allocates each item of revenue, expense, and rate base to the appropriate jurisdiction through its monthly accounting process. Costs are directly assigned where possible. Where direct assignment is not feasible, costs are allocated based on appropriate jurisdictional allocation factors designed to reflect cost causation. The allocation methods and procedures are similar to those previously used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. **What test period are you using to determine the revenue requirement?**

A. The revenue requirement is based on a projected 2027 test period. Montana-Dakota is using a future test year in accordance with North Dakota Century Code § 49-05-04.1.

Q. **What are the primary drivers of the Company's proposed revenue requirement increase?**

A. As summarized by Ms. Nicole Kivisto, the revenue requirement increase is largely driven by:

Table 2: Change in Revenue Requirement

Amount (in millions)	Revenue Requirement
Incremental Rate Base	$15.3
Operating Income Items:	
Margin	(2.2)
Other Revenue	(1.3)
O&M	15.4
Depreciation Expense	6.5
Other Taxes	0.8
Revenue Requirement Increase	$34.5

Q. **Please describe the development of the projected cost of service for 2026 and 2027.**

A. The projected 2026 and 2027 cost of service is presented in Statement A, with schedules supporting the income statement in

Statements F, G, H, I, and J. The revenues and expenses reflect the annual level that is projected for 2026 and 2027. Likewise, the rate base reflects average 2026 and 2027 plant and related balances with supporting schedules in Statements B,C,D,H and J.

Income Statement

Q. Please describe the development of the projected revenues and expenses.

A. Revenue and expenses were developed using Adjusted 2025 as the baseline to reflect base rate recovery in this filing, and to exclude Glen Ullin Station 6 Waste Heat Generator beginning in 2026. The projected revenues for 2026 and 2027 are summarized in Statement F. The development of the projected sales forecasts is discussed in the testimony of Mr. Brian Giggee, and the development of the retail sales revenues is discussed in the testimony of Ms. Stephanie Bosch.

Base Rates: The projected base revenues for 2026 and 2027 are summarized on Statement F, page 1. Retail sales revenues reflect projected volumes at current rates, based on Adjusted 2025. The supporting detail is provided on Statement F, Schedule F-1, page 1.

The Company reported wholesale sales revenue in 2025 and is projecting additional wholesale sales revenue in the test period. The associated costs are reflected as an offset to Fuel and Purchased Power expense.

Other operating revenues are projected to decrease, as detailed on Statement F, Schedule F-2, page 1, which is primarily attributable to a reduction in rent-related revenues due to the expiration of the Transition Service Agreement associated with the Everus spinoff.

Late payment revenues were projected for 2026 and 2027 based on the 2025 ratio of late payment revenue to retail sales revenue of 0.175 percent applied to Projected 2026 and 2027 retail sales revenue.

Q. Please describe the development of the operation and maintenance (O&M) expenses.

A. The projected 2026 and 2027 O&M expenses are summarized on Statement G, Schedule G-1, pages 5 through 8, with the detail provided on pages 9 through 27. Overall, the projected O&M expenses reflect current cost levels, known changes, and modest inflation adjustments, as further discussed below.

Q. Please describe the development of the projected other O&M expense.

A. O&M expenses were reviewed and projected by resource or cost category on a North Dakota electric basis. Montana-Dakota used the Adjusted 2025 calculation as the starting point to develop the projected 2026 and 2027 O&M expense levels.

Montana-Dakota projected the O&M expenses for 2026 by by reviewing current information, as well as discussions with operations personnel to determine the best information for 2026 . Projected 2027 expenses are based on Projected 2026 expenses with the Company's best estimate when changes are known or based on an inflation factor when appropriate.

Q. How did Montana-Dakota calculate the inflation factors?

A. The Company calculated the inflation factors using an average of inflation projections published by the Organization for Economic Cooperation and Development, Congressional Budget Office, International Monetary Fund, and PricewaterhouseCoopers. The resulting average inflation factors are 2.28 percent for 2026 and 2.05 percent for 2027.

Q. Have you updated the fuel and purchased power costs?

A. Yes. The fuel and purchased power cost adjustment has been included on Statement G, Schedule G-1, page 9. The fuel and purchased power cost adjustment has been computed in total and allocated to both primary and secondary sales classes for the purposes of determining the recovery in revenue on a per unit basis.

Q. Would you describe the projected fuel and purchased power costs for the 2027 test year, and the primary factors contributing to the change from 2025?

A. Compared to the costs reflected as of December 31, 2025, the Company projects lower fuel and purchased power costs for 2027, as shown on Statement Workpaper G, Schedule G-1, page 2. This decrease is primarily attributable to the addition of the Badger Wind Project (Badger Wind). Energy generated by Badger Wind is expected to offset MISO market purchases, thereby reducing fuel and purchased power costs. The estimated energy savings associated with Badger Wind are approximately $11.6 million, or $0.005 per Kwh in 2027, based on projected generation that would otherwise be purchased from the MISO energy market. For a residential customer using 800 Kwh per month, this reflects an estimated average monthly bill decrease of $3.98, or $47.71 annually.

Q. Please describe the development of the labor and benefits expense.

A. Labor and benefits expense is shown on Statement G, Schedule G-1, page 10. The projection begins with actual labor expense for the twelve months ended December 31, 2025, adjusted to reflect the Adjusted 2025 baseline.

Montana-Dakota expects to hire 5 full-time employees in various departments including; Fleet, Regulatory, Community Engagement, Engineering and Power Production. These new positions and the labor expenses associated are further defined in Statement Workpaper G, Schedule G-1, pages 10 through 12. Additional benefits associated with the new positions discussed above are reflected on Statement Workpaper G, Schedule G-1, pages 14 and 15.

The overall projected labor increase for 2026 is 5.35 percent, which includes a 6.00 percent increase for bargaining unit employees pursuant to the negotiated union contract and a 5.00 percent increase for non-bargaining unit employees. Incentive compensation has been adjusted to reflect 11.20 percent of straight time and vacation pay. The overall projected labor increase for 2027 is 4.48 percent, which includes a 3.50 percent increase for bargaining unit employees pursuant to the negotiated union contract and a 5.00 percent increase for non-bargaining unit employees.

Benefits are shown on Statement G, Schedule G-1, page 12, with additional support provided on Statement Workpaper G, Schedule G-1, pages 13 through 15. Benefits expense includes medical/dental insurance, pension, post-retirement, 401(k), and workers' compensation. Each of these items are adjusted individually as follows:

- Medical/dental expense for 2026 and 2027 reflect an increase of 5.00 percent per year based on premiums in effect for 2026.
- Pension and post-retirement expense for 2026 and 2027 is based on the 2025 Actuarial Estimate.
- Projected 401(k), workers' compensation, and other benefits expense reflected the straight time labor increase of 5.35 percent for 2026 and 4.48 percent for 2027.

Q. Please describe the other projected O&M expense items.

A. Subcontract labor expense, shown on Statement G, Schedule G-1, pages 13 and 14, is based on the Adjusted 2025 amount. The projected subcontract labor expense for 2026 and 2027 was adjusted to reflect increases in maintenance contract costs and the retirement of Glen Ullin Station 6, as detailed on Statement Workpaper G, Schedule G-1, page 16. In addition, inflation factors of 2.28 percent for 2026 and 2.05 percent for 2027 were applied based on the average of the indices discussed above.

Big Stone and Coyote expenses, shown on Statement G, Schedule G-1, page 15, are based on 2025 actual expenses. Projected 2026 and 2027 expenses were adjusted to reflect expected operating costs for 2026 and 2027 with normalized outages scheduled.

Materials expense, as shown on Statement G, Schedule G-1, page 16, reflects the Adjusted 2025 level and includes increases for existing plant maintenance and material requirements, as well as higher transmission and distribution material expense attributable to anticipated increases in applicable tariffs as shown on Statement Workpaper G, Schedule G-1, page 20.

Vehicles and work equipment expense, shown on Statement G, Schedule G-1, page 17, includes all costs associated with the Company's vehicles and equipment, such as backhoes, skid steers, and excavators, including the cost of fuel, insurance, maintenance, and depreciation expense. Depreciation expense for vehicles and work equipment is charged to a clearing account rather than directly to depreciation expense. It is then allocated to O&M expense or capitalized as part of a project based on actual equipment usage. Projected 2026 and 2027 expense is based on projected plant balances applied to the currently approved and/or proposed depreciation rates, as well as projected fuel expense based on the U.S. Energy Information Administration's Short-Term Energy Outlook.

Company utilities expense, shown on Statement G, Schedule G-1, page 18, includes costs for general utilities, electric service, and natural gas consumption in Company buildings. The projected 2026 and 2027 general utilities and electric components are based on Adjusted 2025 expenses, increased by inflation factors of 2.28 percent and 2.05 percent, respectively. The natural gas component is based on 2025 weather-normalized volumes and projected indices for natural gas and propane.

Postage expense, shown on Statement G, Schedule G-1, page 19, reflects the 9.23 percent increase in postage rates effective in 2026. This increase is partially offset by postage savings associated with the number of customers receiving monthly bills electronically as of December 2025.

Postage expense for 2027 is projected to increase by the 2.05 percent inflation rate.

Uncollectible accounts expense, shown on Statement G, Schedule G-1, page 20, was developed using the ratio of the three-year average of net write-offs to sales revenue. That ratio was then applied to projected 2026 and 2027 sales revenues, which results in a decrease in uncollectible accounts expense relative to the Adjusted 2025 level.

Advertising expense, shown on Statement G, Schedule G-1, page 21, reflects the elimination of promotional advertising expense from the projected periods. Informational and institutional advertising expenses were also adjusted to exclude amounts not applicable to North Dakota electric operations. Projected 2026 and 2027 advertising expenses were then increased by inflation factors of 2.28 percent and 2.05 percent, respectively.

Industry dues, shown on Statement G, Schedule G-1, page 22, reflect the projected levels of industry dues and eliminate the industry dues not specifically applicable to North Dakota electric operations.

Insurance expense, shown on Statement G, Schedule G-1, page 23, reflects the current insurance premium levels in effect as of April 2026 for the projected 2026 period. Projected 2027 insurance expense reflects a 5.00 percent increase based on recent insurance cost trends.

Regulatory commission expense, shown on Statement G, Schedule G-1, page 24, reflects the projected costs to be incurred in this filing, amortized over a three-year period; the three-year average of ongoing regulatory commission expense; and costs associated with the common and electric depreciation studies, amortized over five years. These amounts are reflected in projected 2026 and 2027 expense.

Software maintenance expense, shown on Statement G, Schedule G-1, page 25, is based on estimated 2026 expense levels. Projected 2027 software maintenance expense reflects an overall increase of 4.46 percent due to increased license renewal costs, mandated security requirements, and the shift to cloud-based software licensing, which results in certain costs being recorded as O&M expense rather than capital.

Rent expense, shown on Statement G, Schedule G-1, page 26, is based on the Adjusted 2025 level and includes projected 2026 and 2027 changes related to mobile radio tower sites.

Legal expense, shown on Statement G, Schedule G-1, page 27, is based on a five-year average expense level, adjusted for inflation of 2.28

percent in 2026 and 2.05 percent in 2027. Projected legal expense for 2026 and 2027 excludes fees associated with the congestion litigation addressed in the Commission's Order in Case No. PU-24-388. Those costs were approved for deferred accounting treatment and have been recovered through the Fuel and Purchased Power Adjustment.

The O&M expense categories discussed above represent approximately 97.68 percent of total North Dakota electric O&M expense, as shown on Statement G, Schedule G-1, pages 1 and 2. The remaining O&M expense categories, which represent approximately 2.32 percent of total North Dakota electric O&M expense, were adjusted by inflation factors of 2.28 percent for 2026 and 2.05 percent for 2027.

Depreciation

Q. Please describe the calculation of depreciation expense.

A. The adjustments to depreciation expense are summarized on Statement H, page 1. The adjustment includes three components:

1. Annual depreciation expense was calculated based on the average projected level of plant in service.
2. Concentric Advisors, ULC prepared a depreciation study at the Company's request for common assets based on plant balances as

of December 31, 2021. The detailed report prepared by Concentric Advisors, ULC is provided in Exhibit No.___(BJD-3). All other electric depreciation rates proposed in this filing remain consistent with the rates approved in the Company's most recent electric rate case, Case No. PU-22-194.

3. Depreciation expense also reflects the impact of the latest decommissioning studies and related projected decommissioning balances. The current estimate for North Dakota's share of decommissioning costs indicates that the unamortized balance as of December 31, 2026, requires annual amortization of $688,442. This amount is slightly higher than the current annual amortization due to updated decommissioning studies.

Q. Have there been any other changes that are necessary to incorporate into the calculation of depreciation expense in this filing?

A. Yes. FERC Order No. 898 (Order No. 898) updated the Uniform System of Accounts by introducing new accounts and subaccounts, enhancing the level of detail required for recording certain utility assets and associated items. Among other things, the Order added or revised accounts for renewable generation plant, clarified the functional classification of certain energy storage assets, addressed the accounting treatment for environmental credits, and updated account detail for certain information technology and communications equipment.

Q. How were the depreciation rates determined for the new accounts?

A. Montana-Dakota initiated a depreciation study specifically which will include the new or revised accounts established under Order No. 898; however, as of the date of filing this study has not been completed. Therefore, the Company reviewed the requirements of Order No. 898 and transferred the affected assets into the appropriate new FERC accounts. At the time of transfer, the depreciation rates from the original accounts were applied to these assets. Until a future depreciation study is performed, these assets will continue to be depreciated using the authorized rates associated with their previous accounts. This approach supports compliance with federal accounting requirements and maintains transparency in the presentation of plant and depreciation expense in this case. As a result, the Company's implementation of Order No. 898 will not result in a change in depreciation expense in total.

<u>Taxes</u>

Q. How were taxes other than income projected?

A. Projected taxes other than income are shown on Statement I. As shown on Statement I, Schedule I-1, page 1, ad valorem taxes were calculated using the projected 2026 and 2027 average plant in service balances and applying the effective tax rate based on the ratio of the Adjusted 2025 ad valorem taxes to the Adjusted 2025 plant balances by function.

Projected payroll taxes, shown on Statement I, Schedule I-1, page 2, were calculated by applying the 2025 ratio of payroll taxes to labor expense to projected 2026 and 2027 labor expense.

Production taxes were adjusted to reflect projected 2026 and 2027 generation levels and applicable retail sales volumes. North Dakota coal conversion taxes were also adjusted to reflect projected generation levels. Wind generation tax was removed because it is recovered through the Renewable Rider.

All other taxes other than income were projected to remain at the 2025 level.

Q. Please describe the calculation of federal and state income taxes.

A. The projected income tax calculation for North Dakota electric operations is shown on Statement J. Interest is deductible for tax purposes and the projected interest expense, shown on Schedule J-1, page 1, is calculated on the projected rate base using the projected debt ratio and weighted cost of debt from Statement E, page 1.

North Dakota federal and state income taxes are fully normalized;

therefore, the calculation of income taxes is made on the taxable income after interest, since any tax deductions would be fully offset by deferred income taxes.

<u>Rate Base</u>

Q. Please describe the development of the projected rate base for 2026 and 2027.

A. The rate base is summarized on Statement A, page 3 and shows the Per Books 2025, Adjusted 2025, and projected 2026 and 2027 average rate base for North Dakota electric operations. Statements B, C, D, and J are the supporting components of the projected rate base.

Statement B, page 1 shows the projected plant in service for 2026 and 2027. The projected plant was developed by adding the capital budget items for 2026 to the Adjusted 2025 plant in service balances. The projected 2026 plant is detailed in Statement B, Schedule B-1, pages 1-8. Retirements, based on a three-year average of retirements by function, were deducted and the average 2026 balance was calculated. The process was repeated for 2027 in detail on Statement B, Schedule B-1, pages 9-17.

The detailed capital additions by project for 2026 and 2027 are shown on Statement B, Schedule B-2, pages 1 through 13.

The projected accumulated reserve for depreciation is summarized in Statement C. The projected reserve balances were calculated using the adjusted reserve balances as of December 31, 2025, adding the calculated depreciation expense, and deducting retirements based on a three-year average, as shown on Statement H, Schedule H-2, pages 1 and 2. The average 2026 balances were then calculated, and the same process was repeated for 2027.

Q. How were the working capital items derived?

A. The projected working capital summary is presented on Statement D, page 1, with supporting detail provided on Statement D, Schedule D-1, pages 1 through 11. Materials and supplies, fuel stocks, and prepaid insurance were restated to reflect thirteen-month average balances, as shown on pages 1, 2, and 3.

Materials and supplies reflect actual balances through March 2026, with balances for April 2026 through December 2027 based on prior-period actual results. Prepaid insurance reflects actual balances through

March 2026, with balances for April 2026 through December 2027 based on projected insurance expense.

The unamortized redemption of preferred stock costs and gain or loss on the sale of buildings were calculated using the December 31, 2025, balances as the starting point. The calculated 2026 changes, which reflect annual amortization, were then added to determine the 2026 balances. The 2025 and 2026 balances were averaged to determine the 2026 average balances, and the same process was repeated to calculate the 2027 average balances, as shown on Statement D, Schedule D-1, pages 4 through 6. Associated accumulated deferred income taxes were also included.

Pension and Post Retirement balances, shown on Schedule D-1, pages 7 and 8, were calculated using the balance as of December 31, 2025 and adding the actuarily determined expense and funding. Statement Workpaper Statement D, Schedule D-1, pages 1-2 show the projected 2026 and 2027 expense.

Customer advances for construction, shown on Statement D, Schedule D-1, page 9, have been restated to a thirteen-month average balance for 2026 and 2027, using actual balances through March 2026.

Q. Please describe how the accumulated deferred income tax balances were developed.

A. The accumulated deferred income tax balances are summarized on Statement J, Schedule J-2, page 1. Projected balances were developed by adding the projected 2026 and 2027 changes in deferred income taxes to the Adjusted 2025 balances and then calculating the average balances for each projected year.

The changes associated with book/tax depreciation are shown on Statement J, Schedule J-2, page 3. These amounts reflect projected changes related to both new plant additions and existing plant. The Company is required to use the proration method to compute deferred taxes for test period filings when forecasted information is used to develop the revenue requirement, in order to comply with IRS normalization rules.

<u>Plant Additions and Retirements</u>

Q. Please describe the significant capital additions included in the projected 2026 and 2027 rate base.

A. The significant capital additions reflected in the projected 2026 and 2027 rate base consist of several major project categories discussed throughout this proceeding. These include transmission substation and line projects—such as the Merricourt and Stanley Substations and the Lignite-to-Kincaid transmission line—addressed in the testimony of Mr. Robert Frank; distribution system investments supporting wildfire mitigation initiatives, as discussed by Mr. Daryl Anderson; replacement of the Company's mobile radio system, as presented by Mr. Giggee; and general plant additions, including the new Mobridge District Office and Warehouse and a new Training Center in Mandan, ND.

<u>Mobridge District Office and Warehouse</u>

Q. Why is a new office and warehouse needed in Mobridge and why are North Dakota customers responsible for a building in South Dakota?

A. The existing Mobridge facilities are outdated and do not adequately support employees or operations. The Company currently operates out of multiple locations and faces space constraints, operational inefficiencies, and other limitations. Although the facility is located in South Dakota, it supports electric operations that serve North Dakota customers.

Q. What alternatives were considered?

A. Montana-Dakota evaluated expanding the existing garage and shop facilities but determined there was insufficient space to meet operational needs.

Q. How will the Company benefit from the new Mobridge facility?

A. The new facility will consolidate employees into one location, eliminate leased warehouse space, and improve access for large equipment and materials along a designated truck route.

<u>Training Center</u>

Q. Why is Montana-Dakota building a new Training Center?

A. The Company's current training space no longer provides sufficient capacity or resources to support comprehensive, hands-on training. The new Training Center is necessary to ensure safe and effective operation of the electric system by providing dedicated space for hands-on training, safety certifications, and emergency response preparation.

Q. What alternatives were considered?

A. The Company evaluated continuing to share space at the Bismarck Service Center; however, space limitations prevent expansion and modernization of training programs.

Q. What are the benefits of the new Training Center?

A. The new facility will include offices, classrooms, and indoor and outdoor training areas designed to support both electric and natural gas training needs, improving safety, efficiency, and workforce readiness.

Q. Were any significant plant retirements reflected in the projected rate base?

A. The projected rate base reflects the retirement of the Glen Ullin Station 6, a 7.5 MW waste heat generating facility located near Glen Ullin, North Dakota. As further outlined in Case No. PU-26-174, the Company determined that retirement is the most cost-effective and prudent course of action, and the unit was retired June 1, 2026. The retirement results in a net reduction to rate base of approximately $2.86 million.

E8760 Alternative Energy Allocation Methodology

Q. Please provide an overview of the E8760 Alternative Energy Allocation Methodology and why you are addressing it in this Case.

A. The E8760 Alternative Energy Allocation Methodology (E8760) was brought forward in the Company's last general electric rate case, Case No. PU-22-194 by Kavita Maini, KM Energy Consulting, LLC, testifying on behalf of Marathon Petroleum Company LP (Marathon). Ms. Maini argued "MDU's flat energy allocator is likely over allocating energy costs to high load factor classes such as the General Primary Class. I therefore recommend that the Commission require the Company to develop and introduce an E8760 allocator to allocate fuel costs recovered through the fuel and purchased power rider. This allocator should be effective with final rates in this case."

The Commission approved an all-party settlement agreement that required Montana-Dakota to file with the Commission an application regarding its fuel and purchased power cost rider that provides an alternative allocation option of allocating these costs to the various classes using the E8760 allocation methodology. On March 6, 2024 Montana-Dakota submitted a compliance filing in Case No. PU-24-099 that compared the results of the fuel and purchased power costs calculated pursuant to Fuel and Purchased Power Adjustment Rate 58 (Rate 58) and compare those results with a similar calculation utilizing the E8760 methodology.

In that filing, Montana-Dakota stated its preference was to investigate the development of the E8760 allocation method, prepare an evaluation, and offer a proposal in its next North Dakota general electric rate case. Deferring allowed the Company additional time to structure and evaluate the Company's load research study with E8760 classifications in mind and review the implications for the Company's jurisdictional allocations as they relate to the Company's fuel and purchased power costs. Montana-Dakota has historically performed load research studies only in the context of a rate case. For the purposes of a properly supported E8760 allocation method, annual load research studies were performed to ensure all classes are properly represented and anomalies from any one annual period were properly mitigated.

The Commission issued an Order on October 22, 2024 stating that Montana-Dakota shall file an analysis utilizing the E8760 allocator methodology concurrent with its next electric rate case.

Q. Has the Company performed an analysis of the E8760 allocation for fuel and purchased power costs?

A. Yes. The Company has prepared an analysis utilizing the E8760 allocation as shown in Exhibit No.__(BJD-4) and compared those results to the allocation methodology pursuant to Rate 58.

One important item that was not reflected in Marathon's recommendation is that Montana-Dakota operates an integrated electric utility covering portions of North Dakota, South Dakota and Montana. The Company's analysis was prepared only for the North Dakota portion of the fuel and purchased power costs and ignores the portion to Montana and South Dakota customers. While that may not seem important, the Company's procurement of energy and capacity needs are developed on an integrated system basis. Therefore, not considering nearly 30 percent of the responsibility will potentially misrepresent cost causation. Lastly, both Montana and South Dakota's fuel and purchased power adjustment mechanisms are very similar to North Dakota's current methodology.

Based on the analysis of North Dakota only, the Company demonstrated this change would shift cost responsibility among customer classes, which was expected. In particular, the E8760 methodology would assign a greater share of costs to residential customers while reducing the share assigned to certain higher-load-factor classes. For a residential customer using 800 Kwh per month, the E8760 methodology would result in an estimated increase of approximately $9 per year. Given the affordability issues for residential customers and the additional administrative burden and limitations of calculating and maintaining the E8760 allocation methodology on an integrated system basis, the Company proposes to continue utilizing the current allocation method under Rate 58.

Interim Revenue Requirement

Q. Is Montana-Dakota seeking an interim increase in this case?

A. Yes. As stated by Ms. Kivisto, Montana-Dakota is seeking interim rate relief in this case pursuant to NDCC §49-05-06.

Q. What amount of interim rate relief is the Company seeking?

A. The Company has calculated a net interim revenue requirement increase of $26,347,265 based on the 2027 projected cost of service, which is presented in Exhibit No.__(BJD-2) and Statement A of the Interim Application.

Q. Please describe how the interim revenue requirement was calculated and how the interim revenue requirement differs from that described above.

A. Pursuant to NDCC §49-05-06, section 2, the interim rate request has been calculated using the proposed test year cost of capital, rate base, and expenses, except for the following:

- The rate of return on common equity was set at 9.750 percent, the amount equal to that authorized by the commission in the Company's most recent rate proceeding (Case No. PU-22-194);
- Depreciation rates and regulatory commission expense were set equal to those currently in effect as stated in the most recent rate proceeding; and
- Incentive compensation was reduced by $1.8 million, which was the amount stated in the settlement agreement in the most recent rate proceeding.

Lastly, the interim rates will be applied to ensure there is no change to existing rate design as further described by Ms. Bosch.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS

BASE RATES	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$190,458,513	**$34,494,537**		$224,953,050
Wholesale Sales Revenue	4,824,692			4,824,692
Other	5,195,734			5,195,734
Total Revenues	$200,478,939	$34,494,537		$234,973,476
Operating Expenses				
Operation and Maintenance				
Cost of Fuel & Purchased Power	$50,904,601			$50,904,601
Other O&M	68,688,248	179,372	2/	68,867,620
Total O&M	$119,592,849	$179,372		$119,772,221
Gain/Loss on Environmental Credits	(1,033,138)			(1,033,138)
Depreciation	32,430,158			32,430,158
Taxes Other Than Income	8,457,663			8,457,663
Current Income Taxes	4,129,500	8,374,582	2/	12,504,082
Deferred Income Taxes	0			-
Total Expenses	$163,577,032	$8,553,954		$172,130,986
Operating Income	$36,901,907	$25,940,584		$62,842,491
Rate Base	$785,924,095			$785,924,095
Rate of Return	**4.695%**			**7.996%**

1/ See Statement A, page 2.
2/ Reflects state and federal taxes at 24.4049% after deducting uncollectibles of 0.52%.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
PROJECTED OPERATING INCOME AND RATE OF RETURN - INTERIM
REFLECTING ADDITIONAL REVENUE REQUIREMENTS

BASE RATES	Before Additional Revenue Requirements 1/	Additional Revenue Requirements		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$190,458,513	**$26,347,265**		$216,805,778
Wholesale Sales Revenue	4,824,692			4,824,692
Other	5,195,734			5,195,734
Total Revenues	$200,478,939	$26,347,265		$226,826,204
Operating Expenses				
Operation and Maintenance				
Cost of Fuel & Purchased Power	$50,904,601			$50,904,601
Other O&M	66,909,726	137,006	2/	67,046,732
Total O&M	$117,814,327	$137,006		$117,951,333
Gain/Loss on Environmental Credits	(1,033,138)			(1,033,138)
Depreciation	31,600,264			31,600,264
Taxes Other Than Income	8,333,656			8,333,656
Current Income Taxes	4,789,662	6,396,587	2/	11,186,249
Deferred Income Taxes	0			-
Total Expenses	$161,504,771	$6,533,593		$168,038,364
Operating Income	$38,974,168	$19,813,672		$58,787,840
Rate Base	$786,985,804			$786,985,804
Rate of Return	**4.952%**			**7.470%**

1/ See Statement A, page 2.
2/ Reflects state and federal taxes at 24.4049% after deducting uncollectibles of 0.52%.

Exhibit No.___(BJD-3)
Common Report

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO COMMON PLANT IN SERVICE
as of December 31, 2021

Prepared for Montana-Dakota Utilities Co.
April 2023

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SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to Montana-Dakota Utilities Co.'s ("MDU" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the common general plant accounts, as of December 31, 2021. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of common utility plant, as of December 31, 2021.

The depreciation rates are based on the broad group Straight-Line method using the Average Life Group ("ALG") procedure and were applied on a Remaining Life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2021, are amortized over the composite remaining life of assets.

MDU's accounting policy has not changed since the last depreciation study.

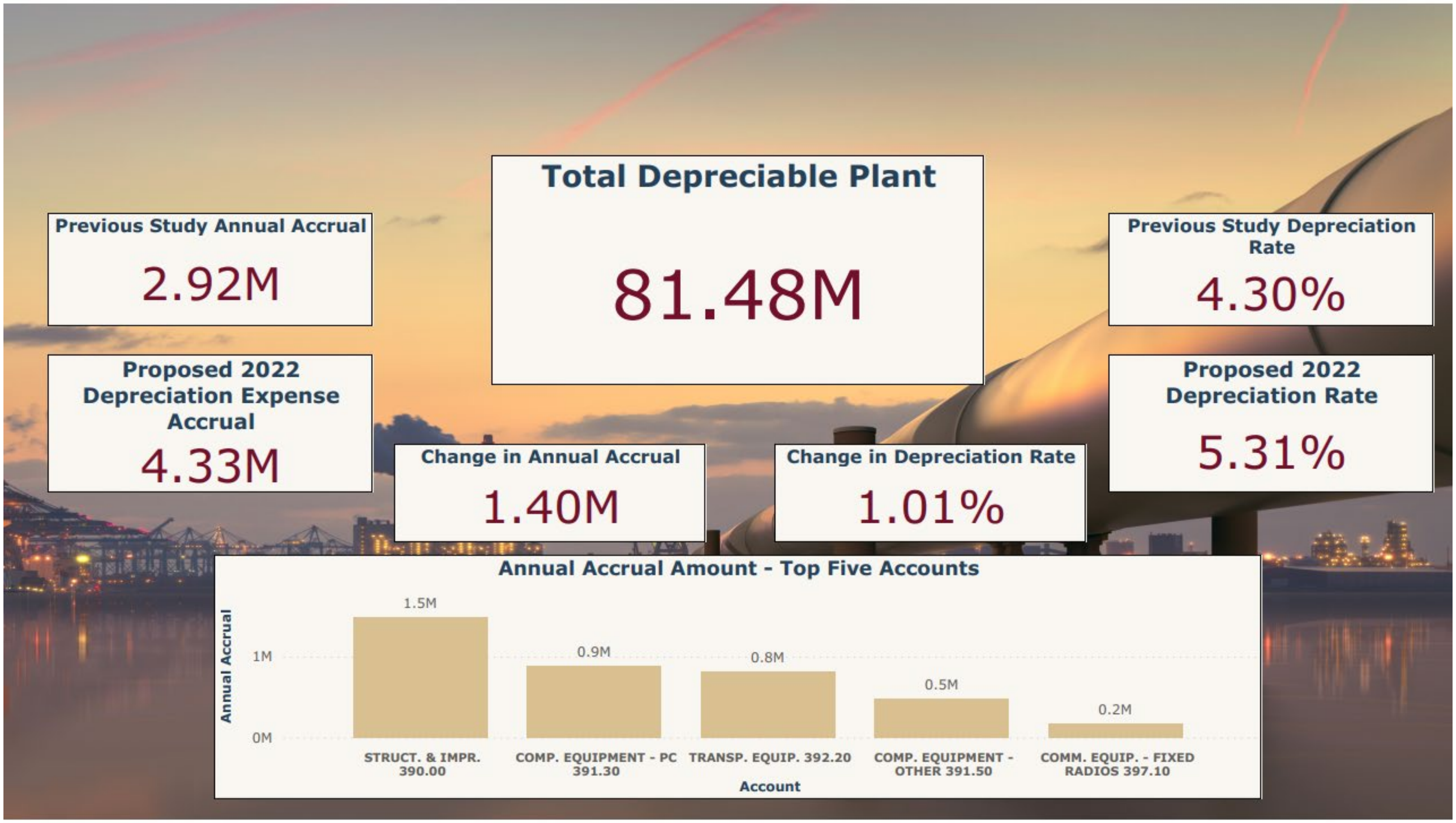
Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to common plant in service, as of December 31, 2021. The annual depreciation accrual rates are summarized by tables related to:

- the total required annual accrual amounts;
- the annual accrual requirements related to the recovery of the original cost of the investment; and
- the annual accrual amount related to the recovery of the expected net salvage requirements at the time of retirement.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $4.3 million, when applied to depreciable plant study balances, as of December 31, 2021, of $81.5 million. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
General Plant	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970
TOTAL	**$81,481,558**	**4.30%**	**$2,924,572**	**5.31%**	**$4,327,970**


Total Depreciable Plant
81.48M
Previous Study Annual Accrual
2.92M
Previous Study Depreciation Rate
4.30%
Proposed 2022 Depreciation Expense Accrual
4.33M
Proposed 2022 Depreciation Rate
5.31%
Change in Annual Accrual
1.40M
Change in Depreciation Rate
1.01%
Annual Accrual Amount - Top Five Accounts
Annual Accrual
1M
0M
1.5M
0.9M
0.8M
0.5M
0.2M
STRUCT. & IMPR. 390.00
COMP. EQUIPMENT - PC 391.30
TRANSP. EQUIP. 392.20
COMP. EQUIPMENT - OTHER 391.50
COMM. EQUIP. - FIXED RADIOS 397.10
Account

SECTION 2

2 BASIS OF THE STUDY

2.1 Scope

This study sets forth the results of the depreciation study for the common general plant assets of MDU, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the ALG Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU assets in service, as of December 31, 2021.

The service life estimates resulting from the study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data recorded through December 31, 2021;
- a review of MDU company practice and outlook, as they relate to plant operation and retirement; and
- consideration of current practice in the electric and gas system industries, including knowledge of service life estimates used for other electric and gas system companies.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The estimated survivor curves used in this study are based on studies incorporating actual data through 2021 for most accounts.

2.2 Plan of Study

This study is presented in the following order:

Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the basis of the study
Section 3:	Development of the Required Depreciation Rates, presents descriptions of the methods used and factors considered in the service life study
Section 4:	Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation
Section 5:	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, and 1B.
Section 6:	Presents the results of the Retirement Rate Analysis
Section 7:	Presents the results of the Net Salvage Study
Section 8:	Presents the results of the Detailed Depreciation Calculations
Section 9:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10:	Estimation of Net Salvage discusses the methodology used in calculating net salvages

2.3 Depreciation

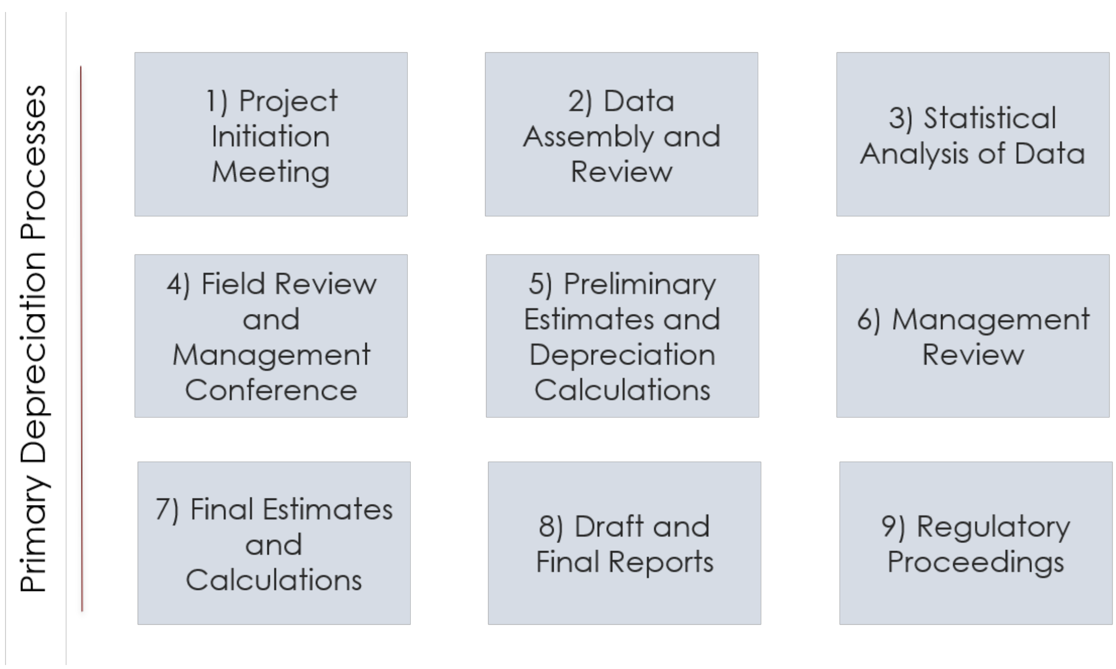
A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. selection of an appropriate grouping procedure;
4. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
5. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

Consistent with the current MDU practice, amortization accounting continues to be recommended for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.



2.4 Information Provided by MDU

MDU has provided Concentric with the required information, as of December 31, 2021 for all accounts being studied in this study. This information includes the following:

- Current balances by vintage year for each account (aged balances) through December 31, 2021. The balances provide the amount of investment sorted by installation year. This file is only inclusive of plant in service and does not include any retirement information;
- retirement transactions for all accounts through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired; and
- cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.5 Data Reconciliation

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;
- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that any adjusting transactions are properly accounted for within the databases.

SECTION 3

3 DEVELOPMENT OF THE REQUIRED DEPRECIATION RATES

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e. Iowa curve) and net salvage recommendations (i.e. the depreciation parameters). Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for MDU have been calculated in accordance with the Straight-Line method, the ALG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of common plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature.

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Gas Utilities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service - that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.1.1 Study Depreciation Methods and Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group (ALG) and Equal Life Group (ELG) procedures.

In the ALG Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

While the Equal Life Group Procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Straight-Line Method, Average Life Group Procedure is a commonly used depreciation calculation that has been widely accepted in jurisdictions throughout North America including MDU in prior studies. Concentric recommends its continued use.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and ALG Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to correct the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.1.2 Changes Since Last MDU Full Depreciation Study

The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the straight-line method, the ALG Procedure applied on a remaining life basis. However, Concentric notes that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintaged remaining life approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a CAD weighted calculation in the textbook Depreciation Systems by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994 under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies was based on a broad averaging of the composite remaining life. The method is also discussed as the Amortization Method (AM) in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

When depreciation rates are calculated utilizing a remaining life technique, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. This calculation is made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole. This calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account.

   MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. Concentric notes that this is the practice employed by virtually all regulated utilities. As such, the accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates and the achieved age of each vintage.

2. The estimated remaining life of each vintage with each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on CAD approach to the remaining life calculations is widely considered to be the most accurate. Concentric agrees and views this methodology as the correct and most appropriate calculation.

3.1.3 Survivor Curves

The use of an average service life or a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

3.1.4 Survivor Curve and Net Salvage Judgments

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric and gas utility industries, and comparisons of the service life and net salvage estimates from Concentric's studies of other utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based mostly in part on historical data related to actual retirement activity for the years 1968 through 2021, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Concentric notes the data from the previous depreciation consultant was used and considered in the historic net salvage analysis, but more relevancy was placed on the more recent data from 2009 through 2021 provided directly to Concentric by MDU. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 390 – STRUCTURES AND IMPROVEMENTS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$57,959,115	71.13%	38-R3	40-R2	0%	-5%

The investment in Structures and Improvements is approximately $57.9 million, representing 71 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1952 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $7,806,923.44 were recorded for this period. The currently approved life parameter is an Iowa 38-R3 that produced a fit with a related residual measure of 3.0467. An Iowa 40-R2 produced a better fit with a residual measure of 2.5362, as depicted on page 6-2. Discussions with MDU operational and management staff indicated that the Iowa 40-R2 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 40-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 40-R2 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of zero percent. This account has shown a wide range in historical net salvage activity since 1968. The range has been from negative 31 percent to positive 43 percent. A three-year band produces results that range from over negative 1,000 percent to over positive 100 percent. The five-year band ranges from over negative 500 to over positive 1,000 percent. The full depth band averages positive 21 percent. At this time, Concentric recommends that a slight step down to a negative five percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 392.1- TRANSPORTATION EQUIPMENT – TRAILERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$18,482	0.02%	25-L1	25-R1	20%	15%

The investment in this account relates to Transportation Equipment - Trailers. The investment in this account is approximately $18 thousand, representing 0.02 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1937 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $55,565.59 were recorded for this period. The currently approved life parameter is an Iowa 25-L1 which produced a fit with a related residual measure of 1.748. An Iowa 25-R1 produced a fit with a related residual measure of 1.7738, as depicted on page 6-6. Discussions with MDU operational and management staff indicated that the Iowa 25-R1 is a good representation of the historical life and future expectations. Based on the above and considerations, and on Concentric's experience, an Iowa 25-R1 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 25-R1 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 20 percent. This account has shown a limited range in the historical net salvage activity with low retirements since 2013. At this time, Concentric recommends that a positive 15 percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 392.2 – TRANSPORTATION EQUIPMENT – VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$8,552,949	10.5%	9-R3	10-L2.5	20%	20%

The investment in this account relates to Transportation Equipment – Vehicles. This includes everything from ¼ ton trucks to ¾ ton trucks, service trucks, and trucks with cranes.

The investment in Transportation Equipment - Vehicles is approximately $8.5 million, representing 10.5 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1979 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $7,601,423.76 were recorded for this period. The currently approved life parameter for the MDU account is an Iowa 9-R3 that produced a fit with a related residual measure of 0.2624. Data analysis and discussion with MDU personnel indicated that a slight adjustment to a 10-L2.5, with a residual measure of 0.1571, produced a better visual and mathematical fit, and is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L2.5 going forward to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 20 percent. This account has shown a close range in historical net salvage activity since 2009. The range has been from positive 31 percent to positive 82 percent. A three-year band produces results that range from positive 15 percent to positive 49 percent. The five-year band ranges from positive 18 percent to positive 68 percent. The full depth band averages positive 31 percent. At this time, Concentric recommends that a positive 20 percent net salvage estimate continue to be used in the depreciation calculations within this study.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable plant in service. The accounts and their amortization periods are as follows:

Account	Title	Investment	Recommended Amortization Period in Years
391.1	Office Furniture & Equipment	$2,130,096	15
391.3	Computer Equipment – PC	$3,638,802	5
391.5	Computer Equipment – Other	$2,045,305	5
393.0	Stores Equipment	$174,519	30
394.1	Tools, Shop, & Garage Equipment	$759,520	20
394.3	Vehicle Maintenance Equipment	$46,590	20
394.4	Vehicle Refueling Equipment	$3,815	20
397.1	Communication Equipment – Fixed Radios	$2,454,294	15
397.2	Communication Equipment – Mobile Radios	$1,069,272	15
397.3	General Telephone Communication Equipment	$681,544	10
397.5	Supervisory & Telemetering Equipment	$15,704	10
397.8	Network Equipment	$387,937	5
398.0	Miscellaneous Equipment	$1,543,614	25

For the purpose of calculating annual amortization amounts, as of December 31, 2021, the book depreciation reserve for each plant account (or sub-account) is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

4.2 Monitoring of Book Accumulated Depreciation

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual vintage remaining lives.

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study and are shown in Tables 1, 1A, and 1B, related to investment as of December 31, 2021. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the ALG procedure, based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The following tables provide summaries by account of the original cost of investment, calculated and booked accumulated depreciation amounts, the required amount of annual depreciation expense, the required depreciation rate to be applied against the original cost of the account and the estimated composite remaining life of the surviving plant in service.

The detailed calculations of annual depreciation applicable to depreciable assets, as of December 31, 2021, are presented in account sequence starting in Section 5 – Page 5-2. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth (for each installation year) the original cost, calculated accrued depreciation and the calculated annual accrual.

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN COMMON PLANT AS OF DECEMBER 31, 2021

- TOTAL -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE	REMAINING LIFE
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	40-R2	-5	57,959,115	16,797,415	17,279,728	1,490,513	2.57%	29.0
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	1,006,971	980,352	144,983	6.81%	7.9
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	1,803,390	1,465,895	886,780	24.37%	2.5
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	990,748	806,878	484,639	23.70%	2.6
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	15	18,482	4,321	4,252	633	3.42%	18.1
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	20	8,552,949	2,647,624	1,941,593	825,496	9.65%	6.1
393.0	STORES EQUIPMENT	30-SQ	0	174,519	44,725	50,428	5,123	2.94%	22.3
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	329,182	602,422	9,640	1.27%	11.3
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	36,560	36,561	2,328	5.00%	4.3
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	3,147	3,815	-	0.00%	3.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	1,108,474	1,075,983	172,894	7.04%	8.2
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	658,235	644,848	75,385	7.05%	5.8
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	508,725	483,979	80,619	11.83%	2.5
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	11,645	7,698	4,356	27.74%	2.6
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	187,973	139,218	97,514	25.14%	2.6
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	529,827	695,508	47,067	3.05%	16.4
TOTAL GENERAL PLANT				**81,481,558**	**26,668,962**	**26,219,158**	**4,327,970**	**5.31%**	
TOTAL COMMON PLANT STUDIED				**81,481,558**	**26,668,962**	**26,219,158**	**4,327,970**	**5.31%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437					
389.0	LAND & LAND RIGHTS GENERAL			3,285,775					
392.3	AIRCRAFT EQUIPMENT			5,104,289					
TOTAL PLANT				157,961,059					

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1A. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN COMMON PLANT AS OF DECEMBER 31, 2021

- LIFE -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE	REMAINING LIFE
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	40-R2	0	57,959,115	15,997,538	18,045,786	1,318,028	2.27%	29.0
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	1,006,971	980,352	144,983	6.81%	7.9
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	1,803,390	1,465,895	886,780	24.37%	2.5
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	990,748	806,878	484,639	23.70%	2.6
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	15	18,482	4,321	4,252	633	3.42%	18.1
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	20	8,552,949	2,647,624	1,941,593	825,496	9.65%	6.1
393.0	STORES EQUIPMENT	30-SQ	0	174,519	44,725	50,428	5,123	2.94%	22.3
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	329,182	602,422	9,640	1.27%	11.3
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	36,560	36,561	2,328	5.00%	4.3
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	3,147	3,815	-	0.00%	3.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	1,108,474	1,075,983	172,894	7.04%	8.2
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	658,235	644,848	75,385	7.05%	5.8
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	508,725	483,979	80,619	11.83%	2.5
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	11,645	7,698	4,356	27.74%	2.6
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	187,973	139,218	97,514	25.14%	2.6
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	529,827	695,508	47,067	3.05%	16.4
TOTAL GENERAL PLANT				**81,481,558**	**25,869,085**	**26,985,216**	**4,155,485**	**5.10%**	
TOTAL COMMON PLANT STUDIED				**81,481,558**	**25,869,085**	**26,985,216**	**4,155,485**	**5.10%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437					
389.0	LAND & LAND RIGHTS GENERAL			3,285,775					
392.3	AIRCRAFT EQUIPMENT			5,104,289					
TOTAL PLANT				157,961,059					

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1B. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF NET SALVAGE IN COMMON PLANT AS OF DECEMBER 31, 2021

- NET SALVAGE -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE
GENERAL PLANT								
390.0	STRUCTURES & IMPROVEMENTS	40-R2	-5	57,959,115	799,877	(766,058)	172,485	0.30%
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	-	-	-	0.00%
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	-	-	-	0.00%
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	-	-	-	0.00%
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	0	18,482	-	-	-	0.00%
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	0	8,552,949	-	-	-	0.00%
393.0	STORES EQUIPMENT	30-SQ	0	174,519	-	-	-	0.00%
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	-	-	-	0.00%
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	-	-	-	0.00%
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	-	-	-	0.00%
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	-	-	-	0.00%
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	-	-	-	0.00%
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	-	-	-	0.00%
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	-	-	-	0.00%
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	-	-	-	0.00%
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	-	-	-	0.00%
TOTAL GENERAL PLANT				**81,481,558**	**799,877**	**(766,058)**	**172,485**	**0.21%**
TOTAL COMMON PLANT STUDIED				**81,481,558**	**799,877**	**(766,058)**	**172,485**	**0.21%**
PLANT NOT STUDIED								
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437				
389.0	LAND & LAND RIGHTS GENERAL			3,285,775				
392.3	AIRCRAFT EQUIPMENT			5,104,289				
TOTAL PLANT				157,961,059				

SECTION 6

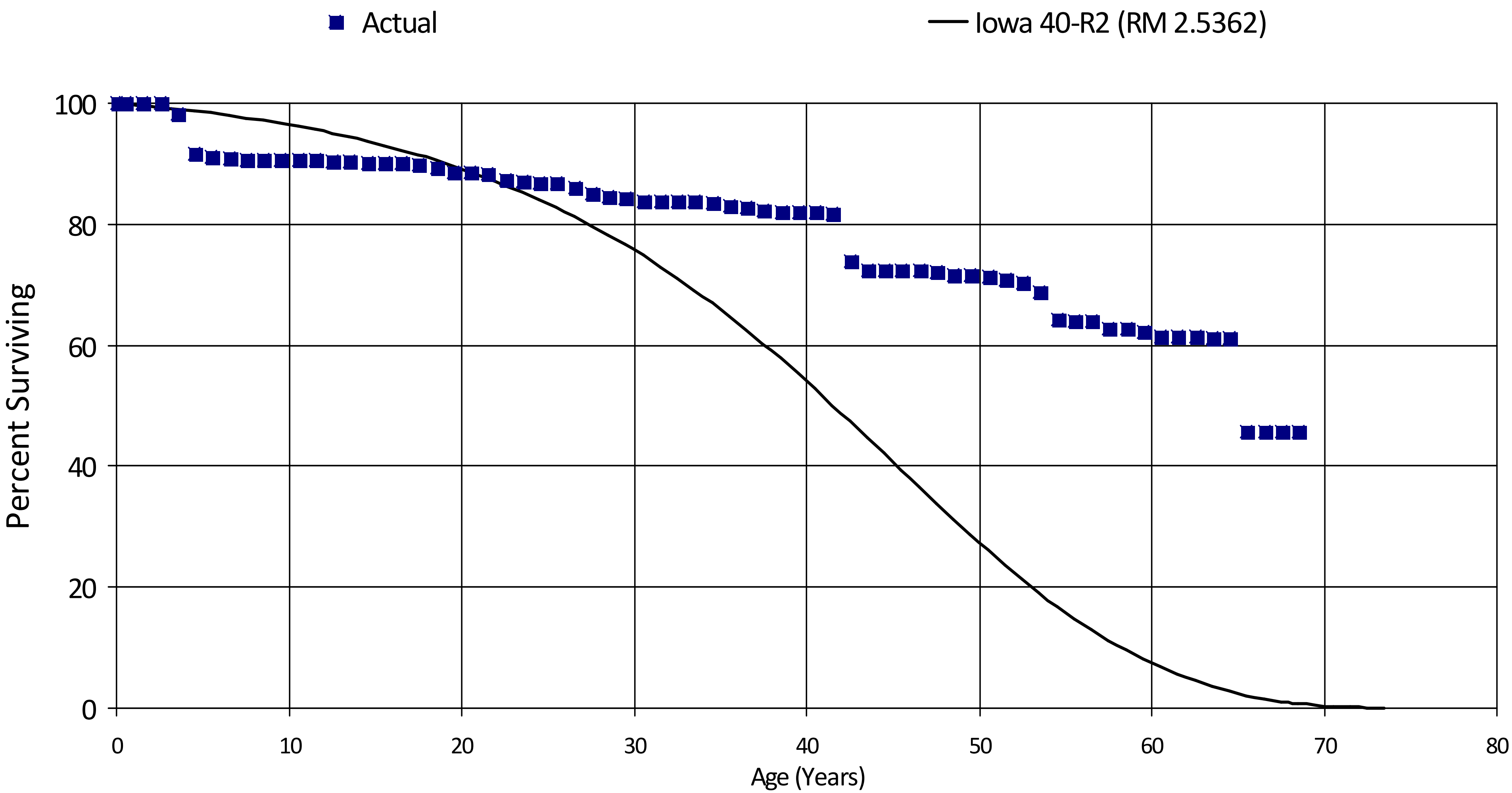
6 RETIREMENT RATE ANALYSIS

MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	65,766,039	13,475	0.00020	0.99980	100.00
0.5	65,679,966	39,092	0.00060	0.99940	99.98
1.5	57,830,913	20,887	0.00036	0.99964	99.92
2.5	56,318,909	1,003,331	0.01782	0.98218	99.88
3.5	52,804,475	3,429,736	0.06495	0.93505	98.10
4.5	45,614,835	263,478	0.00578	0.99422	91.73
5.5	43,986,084	142,215	0.00323	0.99677	91.20
6.5	43,276,893	110,672	0.00256	0.99744	90.91
7.5	27,321,253	24,730	0.00091	0.99909	90.68
8.5	26,974,929	4,989	0.00018	0.99982	90.60
9.5	25,865,503	13,890	0.00054	0.99946	90.58
10.5	25,422,780	0	0.00000	1.00000	90.53
11.5	23,139,844	16,504	0.00071	0.99929	90.53
12.5	23,123,340	40,006	0.00173	0.99827	90.47
13.5	22,285,383	48,884	0.00219	0.99781	90.31
14.5	22,065,083	4,793	0.00022	0.99978	90.11
15.5	22,040,286	15,872	0.00072	0.99928	90.09
16.5	18,129,628	33,129	0.00183	0.99817	90.03
17.5	16,870,206	112,893	0.00669	0.99331	89.87
18.5	16,566,860	130,387	0.00787	0.99213	89.27
19.5	16,029,336	0	0.00000	1.00000	88.57
20.5	15,862,316	59,046	0.00372	0.99628	88.57
21.5	15,171,557	144,610	0.00953	0.99047	88.24
22.5	14,844,554	51,782	0.00349	0.99651	87.40
23.5	14,607,148	40,651	0.00278	0.99722	87.09
24.5	13,922,697	9,569	0.00069	0.99931	86.85
25.5	13,624,592	136,345	0.01001	0.98999	86.79
26.5	23,910,259	227,418	0.00951	0.99049	85.92

MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

27.5	21,009,324	148,104	0.00705	0.99295	85.10
28.5	20,522,861	27,625	0.00135	0.99865	84.50
29.5	20,166,019	139,561	0.00692	0.99308	84.39
30.5	19,921,820	24	0.00000	1.00000	83.81
31.5	19,820,262	21,480	0.00108	0.99892	83.81
32.5	19,764,835	8,757	0.00044	0.99956	83.72
33.5	19,746,416	35,112	0.00178	0.99822	83.68
34.5	19,705,848	130,913	0.00664	0.99336	83.53
35.5	19,190,872	38,262	0.00199	0.99801	82.98
36.5	18,083,098	101,848	0.00563	0.99437	82.81
37.5	11,575,849	63,298	0.00547	0.99453	82.34
38.5	10,681,923	0	0.00000	1.00000	81.89
39.5	7,282,278	0	0.00000	1.00000	81.89
40.5	6,991,807	10,837	0.00155	0.99845	81.89
41.5	6,462,831	629,902	0.09747	0.90253	81.76
42.5	4,657,096	97,810	0.02100	0.97900	73.79
43.5	4,532,160	-13,846	-0.00306	1.00306	72.24
44.5	4,021,935	6,046	0.00150	0.99850	72.46
45.5	3,972,989	0	0.00000	1.00000	72.35
46.5	3,972,989	9,424	0.00237	0.99763	72.35
47.5	3,937,914	27,540	0.00699	0.99301	72.18
48.5	3,812,362	0	0.00000	1.00000	71.68
49.5	3,363,329	11,960	0.00356	0.99644	71.68
50.5	3,293,627	29,387	0.00892	0.99108	71.42
51.5	3,261,294	18,061	0.00554	0.99446	70.78
52.5	3,074,356	67,113	0.02183	0.97817	70.39
53.5	738,579	49,944	0.06762	0.93238	68.85
54.5	523,232	2,459	0.00470	0.99530	64.19
55.5	150,655	0	0.00000	1.00000	63.89
56.5	143,620	2,816	0.01961	0.98039	63.89
57.5	80,158	0	0.00000	1.00000	62.64

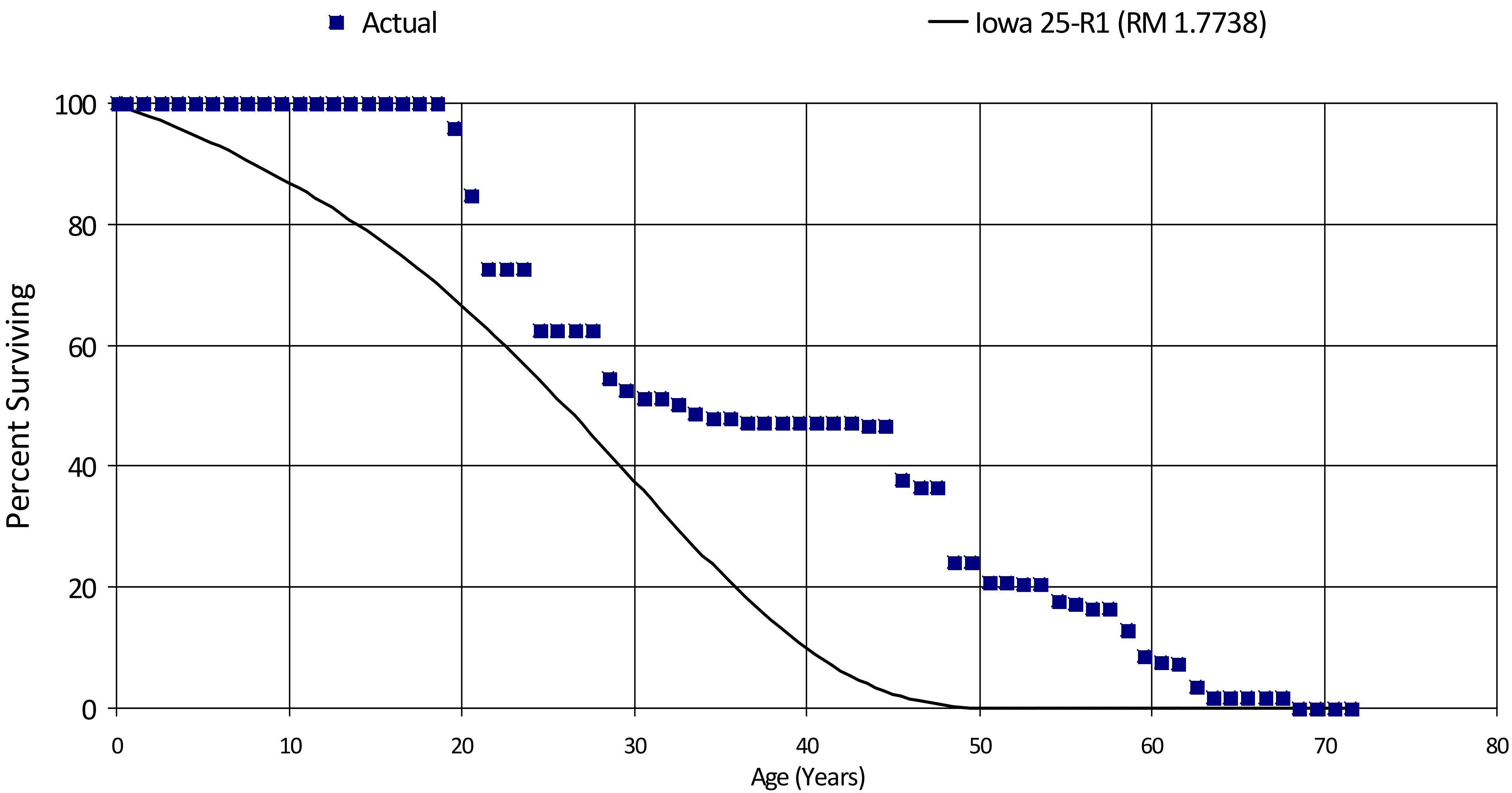
58.5	82,900	630	0.00760	0.99240	62.64
59.5	67,751	891	0.01315	0.98685	62.16
60.5	65,325	0	0.00000	1.00000	61.34
61.5	63,239	0	0.00000	1.00000	61.34
62.5	62,367	185	0.00297	0.99703	61.34
63.5	61,320	0	0.00000	1.00000	61.16
64.5	9,503	2,393	0.25182	0.74818	61.16
65.5	4,602	0	0.00000	1.00000	45.76
66.5	4,585	0	0.00000	1.00000	45.76
67.5	1,102	0	0.00000	1.00000	45.76
68.5	-2,393	0	0.00000	1.00000	45.76
	Totals:	7,806,920			

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	74,048	0	0.00000	1.00000	100.00
0.5	74,048	0	0.00000	1.00000	100.00
1.5	74,048	0	0.00000	1.00000	100.00
2.5	74,048	0	0.00000	1.00000	100.00
3.5	74,048	0	0.00000	1.00000	100.00
4.5	74,048	0	0.00000	1.00000	100.00
5.5	74,048	0	0.00000	1.00000	100.00
6.5	74,048	0	0.00000	1.00000	100.00
7.5	74,048	0	0.00000	1.00000	100.00
8.5	71,565	0	0.00000	1.00000	100.00
9.5	62,980	0	0.00000	1.00000	100.00
10.5	55,566	0	0.00000	1.00000	100.00
11.5	55,566	0	0.00000	1.00000	100.00
12.5	55,566	0	0.00000	1.00000	100.00
13.5	55,566	0	0.00000	1.00000	100.00
14.5	55,566	0	0.00000	1.00000	100.00
15.5	55,566	0	0.00000	1.00000	100.00
16.5	55,566	0	0.00000	1.00000	100.00
17.5	55,566	0	0.00000	1.00000	100.00
18.5	55,566	2,295	0.04130	0.95870	100.00
19.5	53,271	6,178	0.11597	0.88403	95.87
20.5	47,093	6,781	0.14399	0.85601	84.75
21.5	40,312	0	0.00000	1.00000	72.55
22.5	40,312	0	0.00000	1.00000	72.55
23.5	40,312	5,664	0.14050	0.85950	72.55
24.5	34,648	0	0.00000	1.00000	62.36
25.5	34,648	0	0.00000	1.00000	62.36
26.5	34,648	0	0.00000	1.00000	62.36

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

27.5	34,648	4,278	0.12347	0.87653	62.36
28.5	30,371	1,112	0.03661	0.96339	54.66
29.5	29,258	748	0.02557	0.97443	52.66
30.5	28,511	0	0.00000	1.00000	51.31
31.5	28,511	611	0.02143	0.97857	51.31
32.5	27,900	776	0.02781	0.97219	50.21
33.5	27,123	448	0.01652	0.98348	48.81
34.5	26,675	0	0.00000	1.00000	48.00
35.5	26,675	402	0.01507	0.98493	48.00
36.5	26,272	0	0.00000	1.00000	47.28
37.5	26,272	0	0.00000	1.00000	47.28
38.5	26,272	0	0.00000	1.00000	47.28
39.5	26,272	0	0.00000	1.00000	47.28
40.5	26,272	0	0.00000	1.00000	47.28
41.5	26,272	0	0.00000	1.00000	47.28
42.5	26,272	365	0.01389	0.98611	47.28
43.5	25,907	0	0.00000	1.00000	46.62
44.5	25,907	4,902	0.18921	0.81079	46.62
45.5	21,005	671	0.03194	0.96806	37.80
46.5	20,334	0	0.00000	1.00000	36.59
47.5	20,334	6,950	0.34179	0.65821	36.59
48.5	13,384	0	0.00000	1.00000	24.08
49.5	13,384	1,758	0.13135	0.86865	24.08
50.5	11,627	0	0.00000	1.00000	20.92
51.5	11,627	254	0.02185	0.97815	20.92
52.5	11,373	0	0.00000	1.00000	20.46
53.5	11,373	1,439	0.12652	0.87348	20.46
54.5	9,934	333	0.03352	0.96648	17.87
55.5	9,601	417	0.04343	0.95657	17.27
56.5	9,184	0	0.00000	1.00000	16.52
57.5	9,184	2,021	0.22005	0.77995	16.52

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021 Experience Band - 2009 - 2021

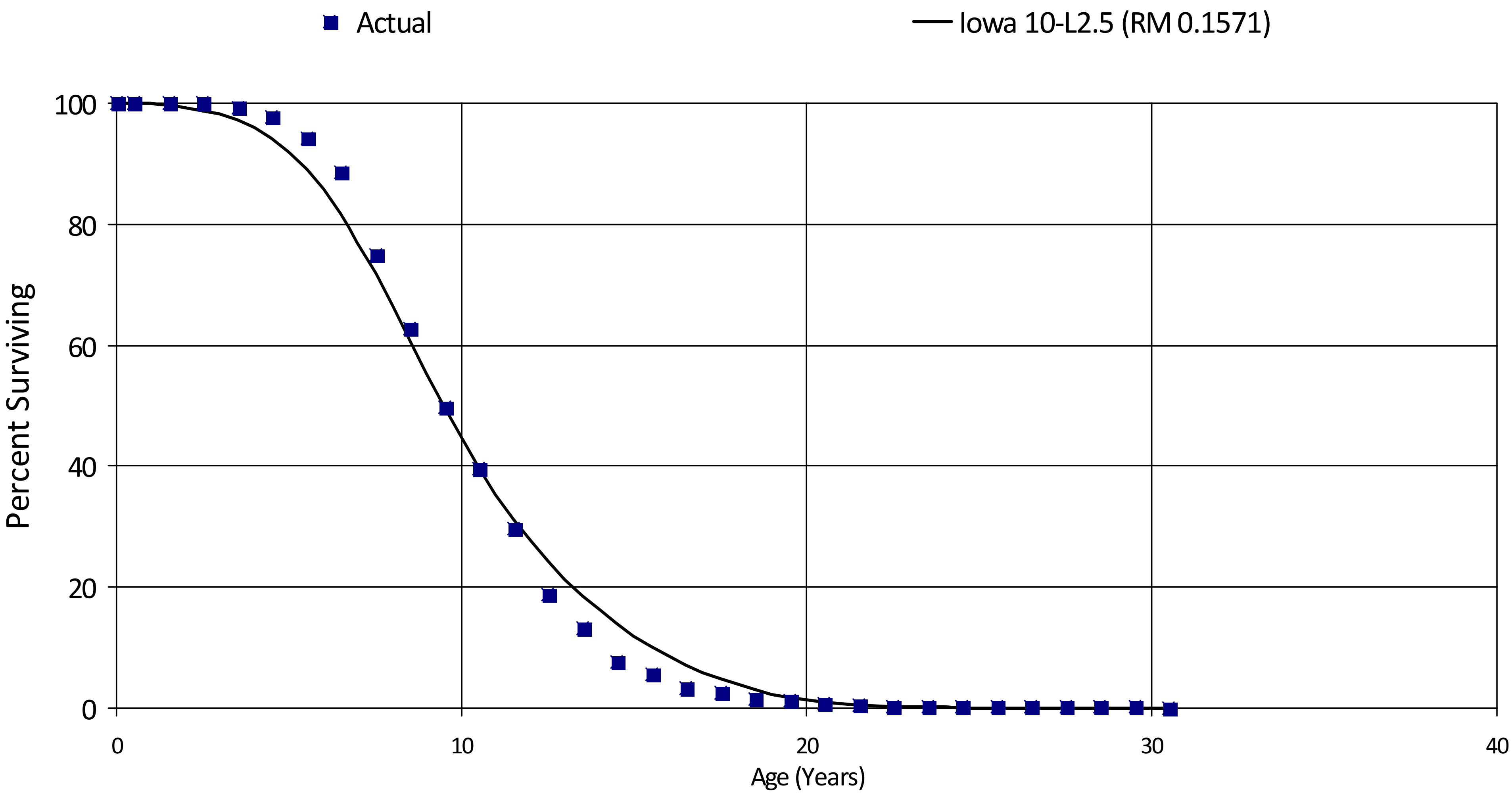
58.5	7,163	2,418	0.33755	0.66245	12.88
59.5	4,745	551	0.11611	0.88389	8.53
60.5	4,195	56	0.01335	0.98665	7.54
61.5	4,139	2,155	0.52066	0.47934	7.44
62.5	1,984	1,012	0.51008	0.48992	3.57
63.5	972	0	0.00000	1.00000	1.75
64.5	972	0	0.00000	1.00000	1.75
65.5	972	0	0.00000	1.00000	1.75
66.5	972	0	0.00000	1.00000	1.75
67.5	972	947	0.97447	0.02553	1.75
68.5	25	0	0.00000	1.00000	0.04
69.5	25	0	0.00000	1.00000	0.04
70.5	25	0	0.00000	1.00000	0.04
71.5	25	25	1.00000		0.04
	Totals:	55,567			

MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021   Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,154,373	0	0.00000	1.00000	100.00
0.5	15,921,146	0	0.00000	1.00000	100.00
1.5	14,926,282	13,683	0.00092	0.99908	100.00
2.5	13,066,738	85,792	0.00657	0.99343	99.91
3.5	12,019,875	196,860	0.01638	0.98362	99.25
4.5	10,971,841	387,493	0.03532	0.96468	97.62
5.5	9,209,486	538,637	0.05849	0.94151	94.17
6.5	7,744,781	1,209,555	0.15618	0.84382	88.66
7.5	5,936,758	968,739	0.16318	0.83682	74.81
8.5	4,799,794	989,697	0.20620	0.79380	62.60
9.5	3,476,252	705,665	0.20300	0.79700	49.69
10.5	2,583,629	648,788	0.25111	0.74889	39.60
11.5	1,896,318	697,431	0.36778	0.63222	29.66
12.5	1,198,887	358,698	0.29919	0.70081	18.75
13.5	840,189	345,824	0.41160	0.58840	13.14
14.5	467,451	127,299	0.27233	0.72767	7.73
15.5	340,151	141,041	0.41464	0.58536	5.62
16.5	199,110	48,943	0.24581	0.75419	3.29
17.5	150,167	54,251	0.36127	0.63873	2.48
18.5	95,916	24,033	0.25056	0.74944	1.58
19.5	58,994	22,124	0.37502	0.62498	1.18
20.5	36,870	12,603	0.34182	0.65818	0.74
21.5	24,268	15,588	0.64233	0.35767	0.49
22.5	8,680	0	0.00000	1.00000	0.18
23.5	8,680	0	0.00000	1.00000	0.18
24.5	8,680	0	0.00000	1.00000	0.18
25.5	8,680	0	0.00000	1.00000	0.18
26.5	8,680	0	0.00000	1.00000	0.18

MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021   Experience Band - 2009 - 2021

27.5	8,680	0	0.00000	1.00000	0.18
28.5	8,680	0	0.00000	1.00000	0.18
29.5	8,680	8,680	1.00005	-0.00005	0.18
30.5	0	0	0.00000	0.00000	0.00
	Totals:	7,601,424			

SECTION 7

7 NET SALVAGE

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 390 - GENERAL PLANT - STRUCTURES & IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1968	4,756	40	1	(662)	(14)	622	13					622	13
1969	23,146	979	4	(350)	(2)	(629)	-3					-3	0
1970	9,536	1,402	15	(5,551)	(58)	4,149	44	1,381	11			1,381	11
1971	56	1,458	2,626	(816)	(1,470)	(642)	-1,156	960	9			875	9
1972	89,020	100	0	(20,851)	(23)	20,751	23	8,086	25	4,850	19	4,850	19
1973	823	-	0	(556)	(68)	556	68	6,888	23	4,837	20	4,135	19
1974	6,649	2,381	36	0	0	(2,381)	-36	6,309	20	4,487	21	3,204	17
1975	0	-		0		0		-608	-24	3,657	19	3,204	17
1976	699	18	3	0	0	(18)	-3	-800	-33	3,782	19	2,801	17
1977	33,563	7,368	22	(10)	(0)	(7,358)	-22	-2,459	-22	-1,840	-22	1,672	9
1978	5,945	471	8	(167)	(3)	(304)	-5	-2,560	-19	-2,012	-21	1,475	8
1979	362	29	8	2	1	(31)	-9	-2,564	-19	-1,542	-19	1,338	8
1980	36,429	-	0	(46,043)	(126)	46,043	126	15,236	107	7,666	50	5,063	29
1981	386	-	0	0	0	0	0	15,337	124	7,670	50	5,063	29
1982	2,390	-	0	35,198	1,473	(35,198)	-1,473	3,615	28	2,102	23	1,966	12
1983	151,268	17,106	11	(52,055)	(34)	34,949	23	-83	0	9,152	24	4,322	17
1984	0	-		(240)		240		-3	0	9,207	24	4,050	17
1985	29,321	-	0	0	0	0	0	11,730	19	-2	0	4,050	15
1986	353,206	23,017	7	(463)	(0)	(22,554)	-6	-7,438	-6	-4,513	-4	2,387	5
1987	114,669	178,551	156	(7)	(0)	(178,544)	-156	-67,033	-40	-33,182	-26	-8,256	-16
1988	1,066	44,428	4,168	(20)	(2)	(44,408)	-4,167	-81,835	-52	-49,053	-49	-10,264	-21
1989	2,908	1,362	47	0	0	(1,362)	-47	-74,771	-189	-49,374	-49	-9,796	-21
1990	1,179	4,184	355	0	0	(4,184)	-355	-16,651	-969	-50,210	-53	-9,515	-22
1991	11,318	21,000	186	0	0	(21,000)	-186	-8,848	-172	-49,899	-190	-10,062	-24
1992	6,400	59,486	929	0	0	(59,486)	-929	-28,223	-448	-26,088	-570	-12,309	-31
1993	66,938	11,015	16	(5,500)	(8)	(5,515)	-8	-28,667	-102	-18,309	-103	-12,013	-29
1994	76,340	3,348	4	(53)	(0)	(3,296)	-4	-22,765	-46	-18,696	-58	-11,650	-27
1995	249,269	48,516	19	(188,096)	(75)	139,580	56	43,590	33	10,057	12	-5,601	-11
1996	174,572	22,546	13	(26,753)	(15)	4,207	2	46,830	28	15,098	13	-5,224	-9
1997	97788.56	4,265	4	(45,364)	(46)	41,099	42	61,629	35	35,215	26	-3,508	-6
1998	255,812	40,399	16		0	(40,399)	-16	1,636	1	28,238	17	-4,825	-7
1999	303792.23	12,226	4	(30,685)	(10)	18,459	6	6,386	3	32,589	15	-4,023	-6
2000	172,070	30,935	18	(10,284)	(6)	(20,651)	-12	-14,197	-6	543	0	-4,577	-6
2001	109,760	14,719	13		0	(14,719)	-13	-5,637	-3	-3,242	-2	-4,904	-6
2002	110,036	29,202	27		0	(29,202)	-27	-21,524	-16	-17,302	-9	-5,663	-7
2003	16416	-	0		0	0	0	-14,640	-19	-9,223	-6	-5,663	-7
2004	0	26,474		(639,099)		612,625		194,474	461	109,611	134	13,073	17
2005	(32,273)	225	(1)		0	(225)	1	204,133	-3,862	113,696	279	12,682	17
2006	13,529	9,973	74	(330,000)	(2,439)	320,028	2,365	310,809	-4,975	180,645	839	21,463	30
2007	45,025	14,205	32	(111,000)	(247)	96,795	215	138,866	1,585	205,845	2,410	23,555	33
2008	26,949	2,070	8		0	(2,070)	-8	138,251	485	205,430	1,930	22,863	33

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 390 - GENERAL PLANT - STRUCTURES & IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2009	542,058	41,867	8	(526,444)	(97)	484,577	89	193,101	94	179,821	151	35,013	43
2010	59,049	3,138		(244)		(2,894)		159,871	76	179,287	131	34,041	42
2011	88,464	19,861	22	(453)	(1)	(19,408)	-22	154,091	67	111,400	73	32,705	40
2012	192,754	3,872	2	(250)	(0)	(3,622)	-2	-8,641	-8	91,316	50	31,819	38
2013	11,998					0		-7,677	-8	91,730	51	31,819	38
2014	762,013	1,212	0		0	(1,212)	0	-1,611	0	-5,427	-2	31,033	31
2015	28,556	93,108	326		0	(93,108)	-326	-31,440	-12	-23,470	-11	28,146	28
2016	4,973,129	120,759	2	(1,250,383)	(25)	1,129,624	23	345,101	18	206,337	17	53,179	25
2017	177,483	191,183	108	(91,149)	(51)	(100,034)	-56	312,161	18	187,054	16	49,774	24
2018	165,707	28,937	17	(1,000)	(1)	(27,937)	-17	333,884	19	181,467	15	48,085	23
2019	282,192	60,776	22	(9,760)	(3)	(51,016)	-18	-59,662	-29	171,506	15	45,977	22
2020	301,002	77,992	26		0	(77,992)	-26	-52,315	-21	174,529	15	43,394	21
2021	222,519.29	124,870	56	(179,182)	(81)	54,312	24	-24,899	-9	-40,533	-18	43,617	21
TOTAL	**10,378,043**	**1,401,070**	**13.50**	**-3,538,286**	**(34.09)**	**2,137,217**	**20.59**						

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 392.1 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - TRAILERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2005	0			(3,500)		3,500						3,500	0
2006	0					0						3,500	0
2007	0			(950)		950		1,483	0			2,225	0
2008	0			(4,850)		4,850		1,933	0			3,100	0
2009	26,134		0	(385)	(1)	385	1	3,228	37	1,937	37	2,421	37
2010	6,896		0	(476)	(7)	476	7	3,387	31	1,332	20	2,032	31
2011	10,083		0	(680)	(7)	680	7	3,614	25	1,468	17	1,807	25
2012	12,453		0	(2,853)	(23)	2,853	23	1,336	14	1,849	17	1,956	25
2013						0		1,178	16	879	8	1,956	25
2014						0		951	23	802	14	1,956	25
2015						0		0	0	707	16	1,956	25
2016						0		0	0	571	23	1,956	25
2017				(4,155)		4,155		1,385	0	831	0	2,231	32
2018				(3,720)		3,720		2,625	0	1,575	0	2,397	39
2019				(19,050)		19,050		8,975	0	5,385	0	4,062	73
2020						0		7,590	0	5,385	0	4,062	73
2021						0		6,350	0	5,385	0	4,062	73
TOTAL	**55,566**	**0**	**0.00**	**-40,619**	**(73.10)**	**40,619**	**73.10**						

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 392.2 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2004	0			(124,143)		124,143						124,143	0
2005	0			(74,531)		74,531						99,337	0
2006	0			(112,620)		112,620		103,765	0			103,765	0
2007	0			(143,063)		143,063		110,071	0			113,589	0
2008	0			(123,203)		123,203		126,295	0	115,512	0	115,512	0
2009	943,733		0	(192,584)	(20)	192,584	20	152,950	49	129,200	68	128,357	82
2010	465,031		0	(126,147)	(27)	126,147	27	147,311	31	139,523	50	128,042	64
2011	137,474		0	(33,401)	(24)	33,401	24	117,377	23	123,680	40	116,211	60
2012	228,230		0	(85,168)	(37)	85,168	37	81,572	29	112,100	32	112,762	57
2013	65,494		0	(49,347)	(75)	49,347		55,972	39	97,329	26	106,421	58
2014	507,650		0	(128,676)	(25)	128,676	25	87,730	33	84,548	30	108,444	51
2015	565,400		0	(135,436)	(24)	135,436	24	104,486	28	86,405	29	110,693	46
2016	1,307,335		0	(135,238)	(10)	135,238	10	133,117	17	106,773	20	112,581	35
2017	832,091	(2)	(0)	(127,071)	(15)	127,073	15	132,582	15	115,154	18	113,616	31
2018	487,481	(15)	(0)	(170,917)	(35)	170,932	35	144,414	16	139,471	19	117,437	32
2019	873,014		0	(198,937)	(23)	198,937	23	165,647	23	153,523	19	122,531	31
2020	734,877		0	(250,036)	(34)	250,036	34	206,635	30	176,443	21	130,031	31
2021	453,616		0	(146,366)	(32)	146,366		198,446	29	178,669	26	130,939	31
TOTAL	**7,601,424**	**(17)**	**(0.00)**	**-2,356,882**	**(31.01)**	**2,356,899**	**31.01**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATIONS

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1953	1,101.98	1,112	1,144	0.9888	13	1.55	8	68.5
1954	863.89	866	891	0.9819	16	1.82	9	67.5
1956	2,508.43	2,478	2,549	0.9677	85	2.37	36	65.5
1957	8,477.14	8,310	8,548	0.9604	353	2.66	133	64.5
1958	708.02	689	709	0.9531	35	2.94	12	63.5
1959	413.04	399	410	0.9462	23	3.23	7	62.5
1960	2,078.30	1,990	2,048	0.9383	135	3.52	38	61.5
1961	1,232.59	1,171	1,205	0.9308	90	3.81	24	60.5
1962	5,940.05	5,598	5,759	0.9234	478	4.10	117	59.5
1964	18,983.94	17,601	18,107	0.9084	1,826	4.68	390	57.5
1965	3,056.19	2,810	2,891	0.9008	318	4.97	64	56.5
1966	143,317.20	130,649	134,400	0.8931	16,083	5.27	3,051	55.5
1967	161,052.17	145,537	149,716	0.8853	19,389	5.57	3,478	54.5
1968	806,161.69	721,976	742,707	0.8774	103,763	5.88	17,638	53.5
1969	49,712.30	44,110	45,377	0.8693	6,821	6.20	1,101	52.5
1971	35,288.82	30,706	31,588	0.8525	5,466	6.85	798	50.5
1972	423,317.91	364,546	375,014	0.8437	69,470	7.19	9,657	49.5
1973	29,001.76	24,707	25,416	0.8346	5,035	7.55	667	48.5
1974	16,140.20	13,596	13,986	0.8253	2,961	7.91	374	47.5
1976	36,819.79	30,275	31,144	0.8056	7,516	8.68	866	45.5
1977	299,565.32	243,149	250,131	0.7952	64,413	9.08	7,095	44.5
1978	6,271.01	5,021	5,166	0.7845	1,419	9.50	149	43.5
1979	516,956.94	408,091	419,809	0.7734	122,996	9.93	12,390	42.5
1980	243,249.46	189,177	194,609	0.7619	60,803	10.37	5,862	41.5
1981	178,300.70	136,511	140,430	0.7501	46,785	10.83	4,319	40.5
1982	1,478,135.25	1,113,244	1,145,209	0.7379	406,833	11.31	35,975	39.5
1983	320,357.51	237,151	243,961	0.7253	92,415	11.80	7,832	38.5
1984	2,770,584.09	2,014,235	2,072,070	0.7123	837,043	12.30	68,027	37.5

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	505,787.81	360,806	371,166	0.6989	159,912	12.82	12,469	36.5
1986	233,540.28	163,317	168,007	0.6851	77,210	13.36	5,779	35.5
1988	4,844.35	3,246	3,339	0.6565	1,747	14.47	121	33.5
1989	4,397.52	2,880	2,963	0.6416	1,655	15.05	110	32.5
1991	59,438.01	37,055	38,119	0.6108	24,291	16.25	1,495	30.5
1992	153,963.54	93,480	96,164	0.5948	65,498	16.87	3,882	29.5
1993	301,888.43	178,276	183,395	0.5786	133,588	17.50	7,632	28.5
1994	2,219,352.92	1,272,963	1,309,515	0.5619	1,020,806	18.15	56,244	27.5
1995	552,945.17	307,591	316,423	0.5450	264,169	18.81	14,045	26.5
1996	288,535.48	155,421	159,884	0.5277	143,078	19.48	7,345	25.5
1997	643,800.12	335,236	344,862	0.5102	331,129	20.16	16,422	24.5
1998	182,161.40	91,529	94,157	0.4923	97,112	20.86	4,656	23.5
1999	182,391.90	88,260	90,794	0.4741	100,717	21.57	4,670	22.5
2000	631,714.02	293,778	302,214	0.4556	361,086	22.28	16,204	21.5
2001	167,019.55	74,475	76,613	0.4369	98,757	23.01	4,291	20.5
2002	407,136.47	173,635	178,621	0.4178	248,872	23.75	10,477	19.5
2003	190,452.63	77,472	79,696	0.3985	120,279	24.50	4,909	18.5
2004	1,226,294.00	474,335	487,955	0.3790	799,654	25.26	31,651	17.5
2005	3,894,785.97	1,427,704	1,468,698	0.3591	2,620,827	26.04	100,664	16.5
2006	20,003.59	6,923	7,122	0.3391	13,882	26.82	518	15.5
2007	171,416.43	55,767	57,369	0.3187	122,619	27.61	4,442	14.5
2008	797,951.24	242,851	249,825	0.2982	588,024	28.41	20,701	13.5
2010	2,282,936.10	597,345	614,497	0.2564	1,782,586	30.03	59,356	11.5
2011	428,832.46	102,907	105,861	0.2351	344,413	30.86	11,161	10.5
2012	1,104,436.85	240,834	247,749	0.2136	911,910	31.69	28,773	9.5
2013	321,593.54	63,012	64,821	0.1920	272,852	32.54	8,386	8.5
2014	15,844,968.08	2,750,706	2,829,689	0.1701	13,807,528	33.39	413,565	7.5
2015	566,977.13	85,649	88,108	0.1480	507,218	34.25	14,811	6.5

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2016	1,365,272.00	175,199	180,230	0.1257	1,253,306	35.11	35,695	5.5
2017	3,759,904.19	396,279	407,658	0.1033	3,540,242	35.98	98,381	4.5
2018	2,511,103.30	206,614	212,547	0.0806	2,424,112	36.87	65,756	3.5
2019	1,491,116.43	87,951	90,477	0.0578	1,475,196	37.75	39,075	2.5
2020	7,809,961.18	277,351	285,315	0.0348	7,915,144	38.65	204,805	1.5
2021	72,597.36	862	887	0.0116	75,341	39.55	1,905	0.5
TOTAL	57,959,115.14	16,797,415	17,279,728		43,577,343		1,490,513	

COMPOSITE ANNUAL ACCRUAL RATE	2.57%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	14.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	28.96

MDU Common

Account #: 391.10 - Office Furniture & Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	168,807.34	163,180	158,867	0.9411	9,941	0.50	9,940	14.5
2008	81,864.85	73,678	71,731	0.8762	10,134	1.50	6,756	13.5
2010	32,157.67	24,654	24,002	0.7464	8,155	3.50	2,330	11.5
2011	74,683.24	52,278	50,896	0.6815	23,787	4.50	5,286	10.5
2012	216,594.23	137,176	133,550	0.6166	83,044	5.50	15,099	9.5
2013	137,346.05	77,829	75,772	0.5517	61,574	6.50	9,473	8.5
2014	551,783.78	275,892	268,599	0.4868	283,185	7.50	37,758	7.5
2015	232,350.52	100,685	98,024	0.4219	134,327	8.50	15,803	6.5
2016	76,630.17	28,098	27,355	0.3570	49,275	9.50	5,187	5.5
2017	62,199.61	18,660	18,167	0.2921	44,033	10.50	4,194	4.5
2018	37,293.50	8,702	8,472	0.2272	28,822	11.50	2,506	3.5
2019	53,306.88	8,884	8,650	0.1623	44,657	12.50	3,573	2.5
2020	356,250.74	35,625	34,683	0.0974	321,567	13.50	23,820	1.5
2021	48,827.31	1,628	1,585	0.0325	47,243	14.50	3,258	0.5
TOTAL	2,130,095.89	1,006,971	980,352		1,149,744		144,983	

COMPOSITE ANNUAL ACCRUAL RATE	6.81%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	7.09
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.91

MDU Common

Account #: 391.30 - Computer Equipment - PC

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	475,481.03	427,933	347,848	0.7316	127,633	0.50	127,633	4.5
2018	961,371.69	672,960	547,019	0.5690	414,352	1.50	276,235	3.5
2019	495,525.06	247,763	201,395	0.4064	294,130	2.50	117,652	2.5
2020	1,420,457.68	426,137	346,388	0.2439	1,074,070	3.50	306,877	1.5
2021	285,966.55	28,597	23,245	0.0813	262,722	4.50	58,383	0.5
TOTAL	3,638,802.01	1,803,390	1,465,895		2,172,907		886,780	

COMPOSITE ANNUAL ACCRUAL RATE 24.37%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.40

COMPOSITE AVERAGE AGE (YEARS) 2.48

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 2.52

MDU Common

Account #: 391.50 - Computer Equipment - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	260,962.58	234,866	191,278	0.7330	69,684	0.50	69,684	4.5
2018	223,116.29	156,181	127,196	0.5701	95,920	1.50	63,947	3.5
2019	656,663.26	328,332	267,397	0.4072	389,266	2.50	155,706	2.5
2020	904,563.36	271,369	221,006	0.2443	683,557	3.50	195,302	1.5
TOTAL	2,045,305.49	990,748	806,878		1,238,428		484,639	

COMPOSITE ANNUAL ACCRUAL RATE	23.70%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	2.42
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.58

MDU Common

Account #: 392.10 - Transportation Equipment - Trailers

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R1
ASL: 25
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	7,414.01	1,857	1,828	0.2900	4,474	17.63	254	10.5
2012	8,585.60	1,955	1,924	0.2637	5,374	18.30	294	9.5
2013	2,482.58	508	500	0.2371	1,610	18.98	85	8.5
TOTAL	18,482.19	4,321	4,252		11,458		633	

COMPOSITE ANNUAL ACCRUAL RATE	3.42%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	9.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.12

MDU Common

Account #: 392.20 - Transportation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 10
Net Salvage: 20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	12,889.32	8,700	6,380	0.6187	3,932	1.56	2,515	19.5
2007	26,914.31	16,167	11,856	0.5506	9,676	2.49	3,883	14.5
2010	38,523.34	21,013	15,409	0.5000	15,409	3.18	4,843	11.5
2011	186,957.73	99,052	72,638	0.4857	76,928	3.38	22,777	10.5
2012	333,845.03	171,905	126,064	0.4720	141,012	3.56	39,572	9.5
2013	168,225.10	83,656	61,348	0.4558	73,233	3.78	19,353	8.5
2014	598,467.61	282,723	207,330	0.4330	271,444	4.09	66,289	7.5
2015	926,067.25	404,588	296,698	0.4005	444,156	4.54	97,855	6.5
2016	1,374,862.37	535,713	392,857	0.3572	707,033	5.13	137,840	5.5
2017	851,173.46	282,506	207,171	0.3042	473,767	5.85	80,969	4.5
2018	961,071.79	255,519	187,380	0.2437	581,477	6.68	87,091	3.5
2019	1,845,860.99	358,718	263,060	0.1781	1,213,629	7.57	160,304	2.5
2020	994,864.15	118,052	86,572	0.1088	709,320	8.52	83,285	1.5
2021	233,226.92	9,313	6,830	0.0366	179,752	9.50	18,920	0.5
TOTAL	8,552,949.37	2,647,624	1,941,593		4,900,766		825,496	

COMPOSITE ANNUAL ACCRUAL RATE	9.65%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	4.58
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.13

MDU Common

Account #: 393.00 - Stores Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1995	10,272.04	9,074	10,231	0.9960	41	3.50	12	26.5
1999	9,502.32	7,127	8,036	0.8456	1,467	7.50	196	22.5
2000	12,486.01	8,948	10,089	0.8081	2,397	8.50	282	21.5
2007	4,385.78	2,120	2,390	0.5450	1,996	15.50	129	14.5
2014	41,481.25	10,370	11,693	0.2819	29,788	22.50	1,324	7.5
2017	15,127.75	2,269	2,559	0.1691	12,569	25.50	493	4.5
2018	15,273.31	1,782	2,009	0.1315	13,264	26.50	501	3.5
2019	22,339.62	1,862	2,099	0.0940	20,241	27.50	736	2.5
2020	13,367.66	668	754	0.0564	12,614	28.50	443	1.5
2021	30,283.24	505	569	0.0188	29,714	29.50	1,007	0.5
TOTAL	174,518.98	44,725	50,428		124,091		5,123	

COMPOSITE ANNUAL ACCRUAL RATE	2.94%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	7.69
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	22.31

MDU Common

Account #: 394.10 - Tools, Shop & Garage Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	46,034.92	40,281	46,035	1.0000	0	2.50	0	17.5
2005	30,657.04	25,292	30,657	1.0000	0	3.50	0	16.5
2006	34,082.71	26,414	34,083	1.0000	0	4.50	0	15.5
2007	15,616.53	11,322	15,617	1.0000	0	5.50	0	14.5
2008	46,070.14	31,097	46,070	1.0000	0	6.50	0	13.5
2009	6,617.89	4,136	6,618	1.0000	0	7.50	0	12.5
2010	29,472.55	16,947	29,473	1.0000	0	8.50	0	11.5
2011	64,949.37	34,098	64,949	1.0000	0	9.50	0	10.5
2012	39,091.97	18,569	39,092	1.0000	0	10.50	0	9.5
2013	33,002.84	14,026	33,003	1.0000	0	11.50	0	8.5
2014	97,204.70	36,452	97,205	1.0000	0	12.50	0	7.5
2015	68,621.75	22,302	68,622	1.0000	0	13.50	0	6.5
2016	42,870.94	11,790	24,282	0.5664	18,589	14.50	1,282	5.5
2017	120,692.81	27,156	49,697	0.4118	70,996	15.50	4,580	4.5
2018	25,947.90	4,541	8,310	0.3203	17,638	16.50	1,069	3.5
2019	27,070.16	3,384	6,192	0.2288	20,878	17.50	1,193	2.5
2020	11,763.56	882	1,615	0.1373	10,149	18.50	549	1.5
2021	19,751.73	494	904	0.0458	18,848	19.50	967	0.5
TOTAL	759,519.51	329,182	602,422		157,098		9,640	

COMPOSITE ANNUAL ACCRUAL RATE	1.27%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.79
COMPOSITE AVERAGE AGE (YEARS)	8.67
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.33

MDU Common

Account #: 394.30 - Vehicle Maintenance Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	9,575.67	8,857	8,858	0.9251	718	1.50	478	18.5
2004	3,101.37	2,714	2,714	0.8750	388	2.50	155	17.5
2006	8,048.09	6,237	6,237	0.7750	1,811	4.50	402	15.5
2007	25,864.74	18,752	18,752	0.7250	7,113	5.50	1,293	14.5
TOTAL	46,589.87	36,560	36,561		10,028		2,328	

COMPOSITE ANNUAL ACCRUAL RATE	5.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.78
COMPOSITE AVERAGE AGE (YEARS)	15.69
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.31

MDU Common

Account #: 394.40 - Vehicle Refueling Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	3,814.65	3,147	3,815	1.0000	0	3.50	0	16.5
TOTAL	3,814.65	3,147	3,815		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	16.50
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	3.50

MDU Common

Account #: 397.10 - Radio Communications Equipment - Fixed

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	6,750.02	6,525	6,334	0.9383	416	0.50	416	14.5
2008	25,327.84	22,795	22,127	0.8736	3,201	1.50	2,134	13.5
2009	678,246.85	565,206	548,639	0.8089	129,608	2.50	51,843	12.5
2010	67,374.52	51,654	50,140	0.7442	17,235	3.50	4,924	11.5
2011	91,653.20	64,157	62,277	0.6795	29,376	4.50	6,528	10.5
2012	27,015.84	17,110	16,609	0.6148	10,407	5.50	1,892	9.5
2013	155,578.42	88,161	85,577	0.5501	70,001	6.50	10,769	8.5
2014	184,685.25	92,343	89,636	0.4853	95,049	7.50	12,673	7.5
2015	54,109.51	23,447	22,760	0.4206	31,349	8.50	3,688	6.5
2016	92,224.08	33,816	32,824	0.3559	59,400	9.50	6,253	5.5
2017	127,555.40	38,267	37,145	0.2912	90,410	10.50	8,611	4.5
2018	158,855.85	37,066	35,980	0.2265	122,876	11.50	10,685	3.5
2019	140,371.08	23,395	22,709	0.1618	117,662	12.50	9,413	2.5
2020	345,707.09	34,571	33,557	0.0971	312,150	13.50	23,122	1.5
2021	298,839.12	9,961	9,669	0.0324	289,170	14.50	19,943	0.5
TOTAL	2,454,294.07	1,108,474	1,075,983		1,378,311		172,894	

COMPOSITE ANNUAL ACCRUAL RATE	7.04%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.44
COMPOSITE AVERAGE AGE (YEARS)	6.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.23

MDU Common

Account #: 397.20 - Radio Communications Equipment - Mobile

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	1,255.68	1,214	1,189	0.9473	66	0.50	66	14.5
2008	95,101.86	85,592	83,851	0.8817	11,251	1.50	7,501	13.5
2009	265,292.40	221,077	216,581	0.8164	48,711	2.50	19,485	12.5
2010	61,810.83	47,388	46,425	0.7511	15,386	3.50	4,396	11.5
2011	56,091.35	39,264	38,465	0.6858	17,626	4.50	3,917	10.5
2012	64,821.15	41,053	40,218	0.6205	24,603	5.50	4,473	9.5
2013	51,295.64	29,068	28,476	0.5551	22,819	6.50	3,511	8.5
2014	97,289.52	48,645	47,655	0.4898	49,634	7.50	6,618	7.5
2015	232,388.11	100,702	98,654	0.4245	133,735	8.50	15,733	6.5
2016	72,591.10	26,617	26,075	0.3592	46,516	9.50	4,896	5.5
2017	44,636.05	13,391	13,118	0.2939	31,518	10.50	3,002	4.5
2018	11,664.67	2,722	2,666	0.2286	8,998	11.50	782	3.5
2020	15,034.10	1,503	1,473	0.0980	13,561	13.50	1,005	1.5
TOTAL	1,069,272.46	658,235	644,848		424,424		75,385	

COMPOSITE ANNUAL ACCRUAL RATE	7.05%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.60
COMPOSITE AVERAGE AGE (YEARS)	9.23
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.77

MDU Common

Account #: 397.30 - General Telephone Communication Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	22,514.99	21,389	20,349	0.9038	2,166	0.50	2,166	9.5
2013	368,021.74	312,818	297,602	0.8087	70,420	1.50	46,947	8.5
2014	48,423.02	36,317	34,551	0.7135	13,872	2.50	5,549	7.5
2015	145,186.63	94,371	89,781	0.6184	55,406	3.50	15,830	6.5
2017	97,398.06	43,829	41,697	0.4281	55,701	5.50	10,127	4.5
TOTAL	681,544.44	508,725	483,979		197,565		80,619	

COMPOSITE ANNUAL ACCRUAL RATE	11.83%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.71
COMPOSITE AVERAGE AGE (YEARS)	7.46
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.54

MDU Common

Account #: 397.50 - Supervisory & Telemetering Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	3,111.92	2,956	1,954	0.6280	1,158	0.50	1,158	9.5
2013	10,073.86	8,563	5,660	0.5619	4,413	1.50	2,942	8.5
2021	2,517.81	126	83	0.0331	2,435	9.50	256	0.5
TOTAL	15,703.59	11,645	7,698		8,006		4,356	

COMPOSITE ANNUAL ACCRUAL RATE	27.74%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	7.42
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.58

MDU Common

Account #: 397.80 - Network Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	7,670.26	6,903	5,113	0.6666	2,557	0.50	2,557	4.5
2018	8,414.86	5,890	4,363	0.5184	4,052	1.50	2,702	3.5
2019	332,413.29	166,207	123,097	0.3703	209,316	2.50	83,726	2.5
2020	25,144.25	7,543	5,587	0.2222	19,557	3.50	5,588	1.5
2021	14,293.86	1,429	1,059	0.0741	13,235	4.50	2,941	0.5
TOTAL	387,936.52	187,973	139,218		248,718		97,514	

COMPOSITE ANNUAL ACCRUAL RATE 25.14%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.36

COMPOSITE AVERAGE AGE (YEARS) 2.42

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 2.58

MDU Common

Account #: 398.00 - Miscellaneous Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	49,732.75	38,792	49,733	1.0000	0	5.50	0	19.5
2003	14,581.60	10,790	14,582	1.0000	0	6.50	0	18.5
2004	19,429.45	13,601	18,626	0.9587	803	7.50	107	17.5
2005	11,868.04	7,833	10,282	0.8664	1,586	8.50	187	16.5
2006	230,098.97	142,661	187,273	0.8139	42,826	9.50	4,508	15.5
2007	14,821.03	8,596	11,284	0.7614	3,537	10.50	337	14.5
2008	48,220.36	26,039	34,182	0.7089	14,039	11.50	1,221	13.5
2010	74,799.68	34,408	45,167	0.6038	29,632	13.50	2,195	11.5
2011	31,820.28	13,365	17,544	0.5513	14,277	14.50	985	10.5
2012	385,182.19	146,369	192,140	0.4988	193,042	15.50	12,454	9.5
2013	44,771.16	15,222	19,982	0.4463	24,789	16.50	1,502	8.5
2014	123,724.15	37,117	48,724	0.3938	75,000	17.50	4,286	7.5
2015	10,522.97	2,736	3,592	0.3413	6,931	18.50	375	6.5
2016	8,540.63	1,879	2,467	0.2888	6,074	19.50	311	5.5
2017	12,051.42	2,169	2,848	0.2363	9,204	20.50	449	4.5
2018	21,759.78	3,046	3,999	0.1838	17,761	21.50	826	3.5
2019	170,767.52	17,077	22,417	0.1313	148,351	22.50	6,593	2.5
2020	67,708.05	4,062	5,333	0.0788	62,375	23.50	2,654	1.5
2021	203,213.70	4,064	5,335	0.0263	197,879	24.50	8,077	0.5
TOTAL	1,543,613.73	529,827	695,508		848,105		47,067	

COMPOSITE ANNUAL ACCRUAL RATE	3.05%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	8.58
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.42

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[3]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

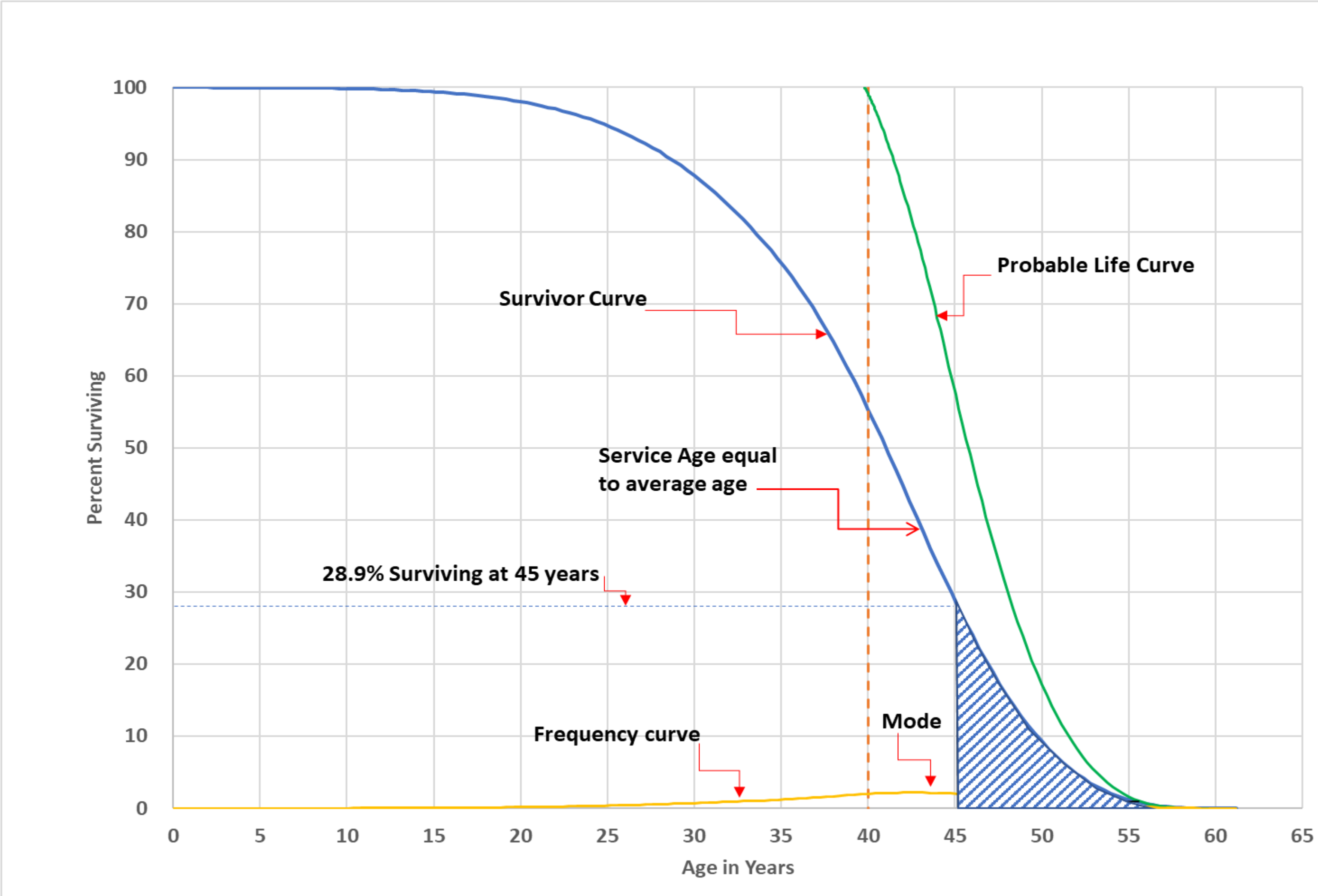
9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age"[4]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[5] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[6]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[3] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[4] *Ibid*, 23.
[5] *Ibid*, 29.
[6] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[7]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[8]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[9] presenting his development of the fourth family consisting of the four O-type survivor curves.

[7] *Ibid*, 21

[8] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[9] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

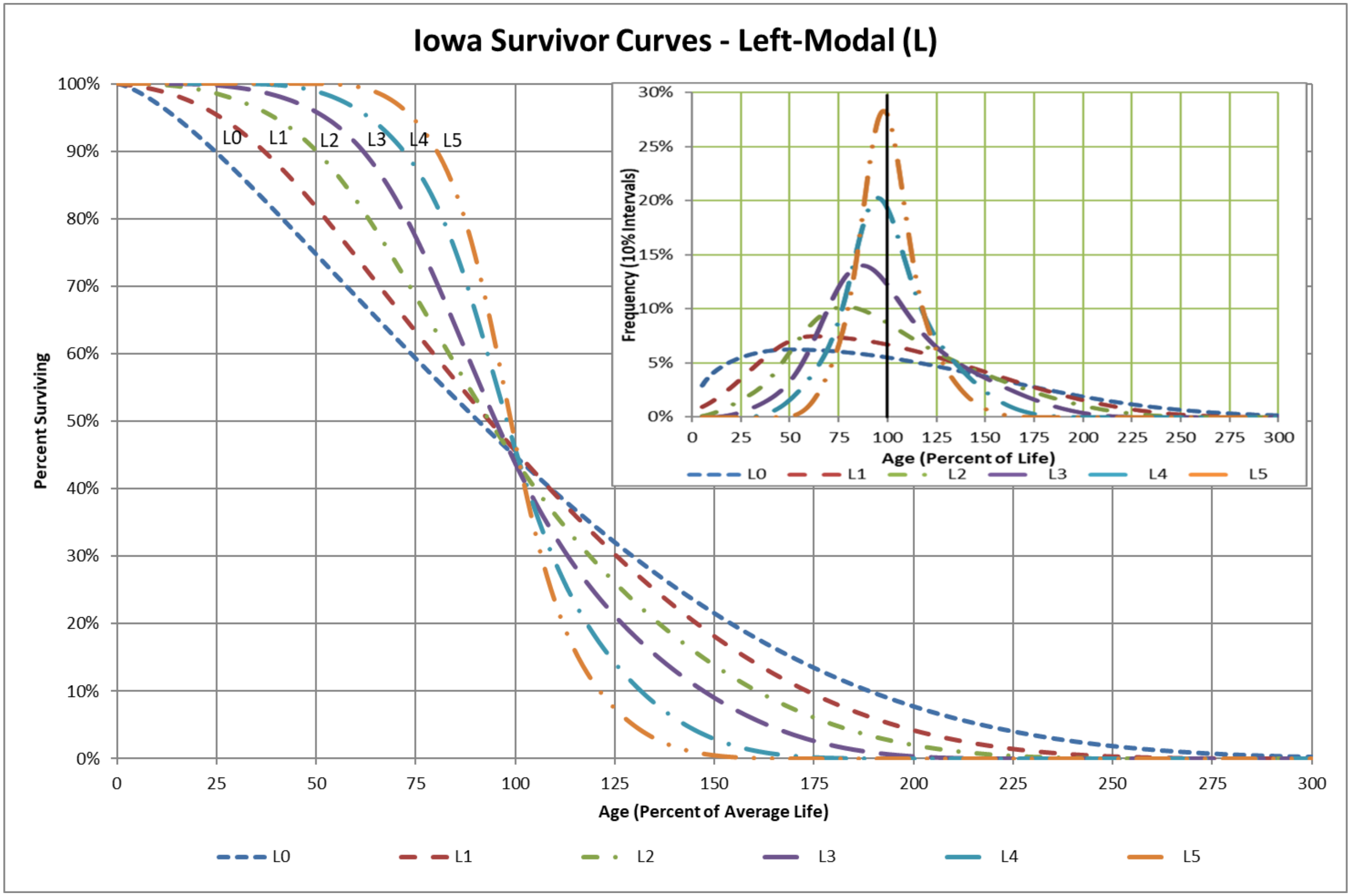


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

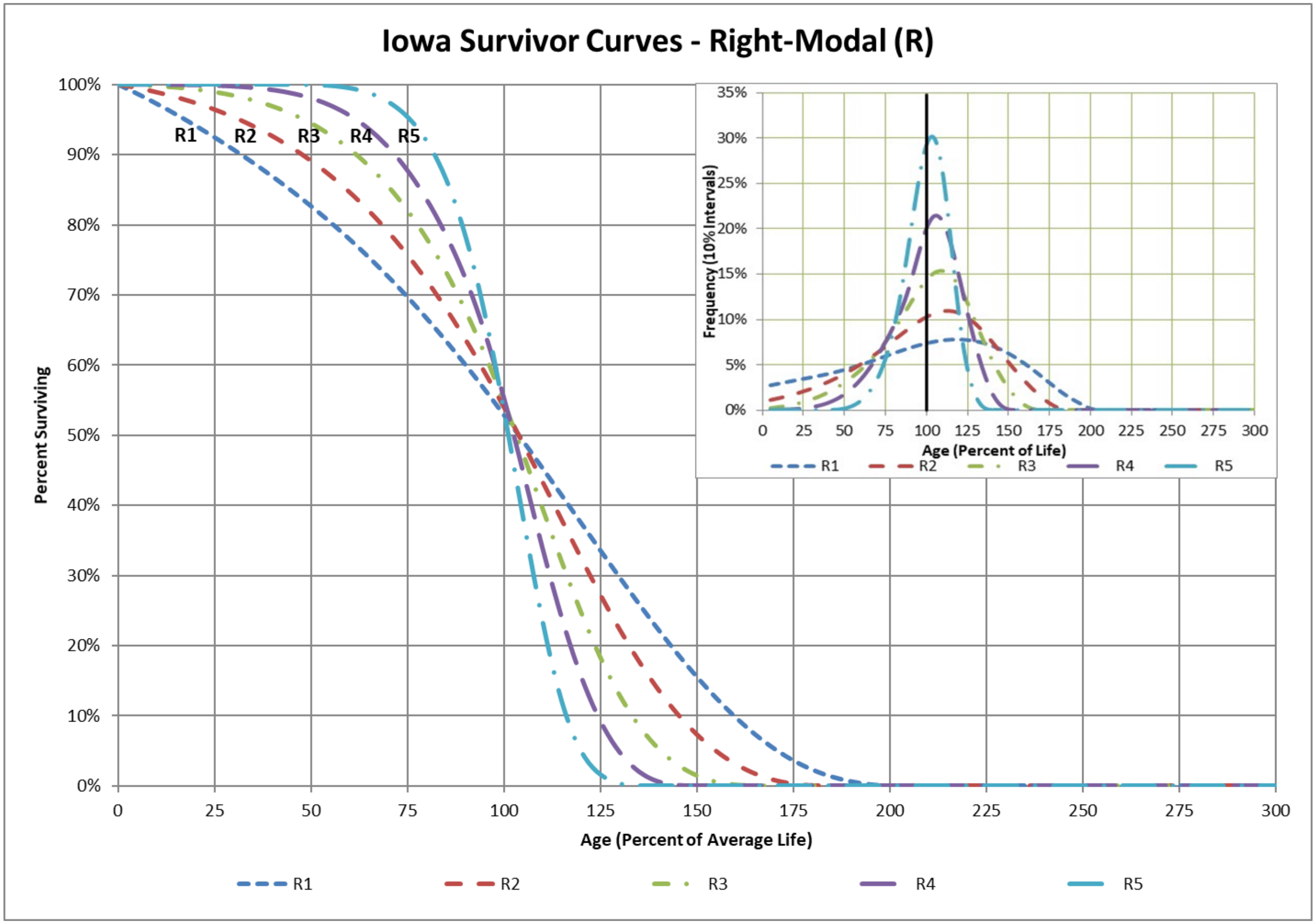


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

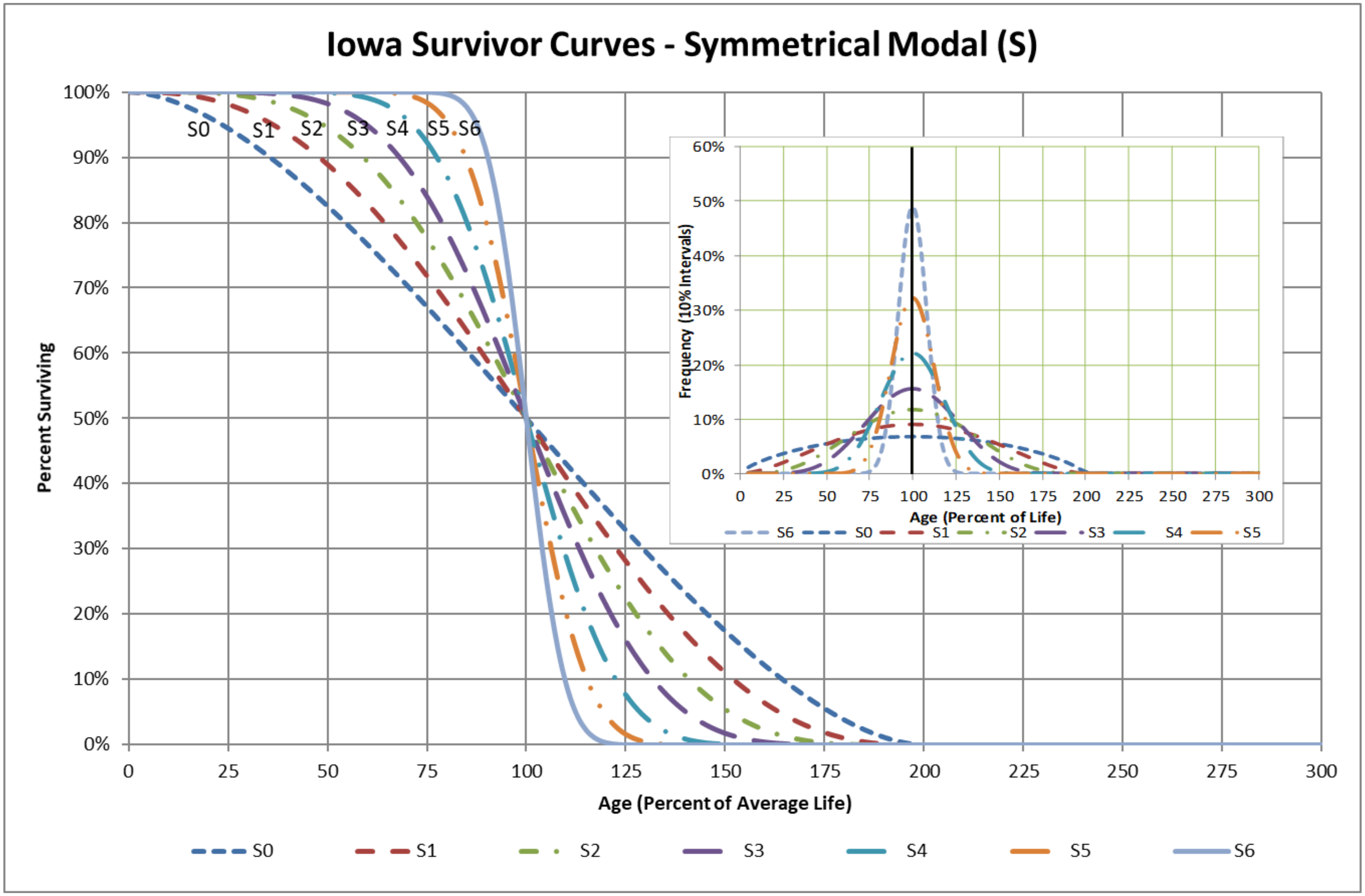
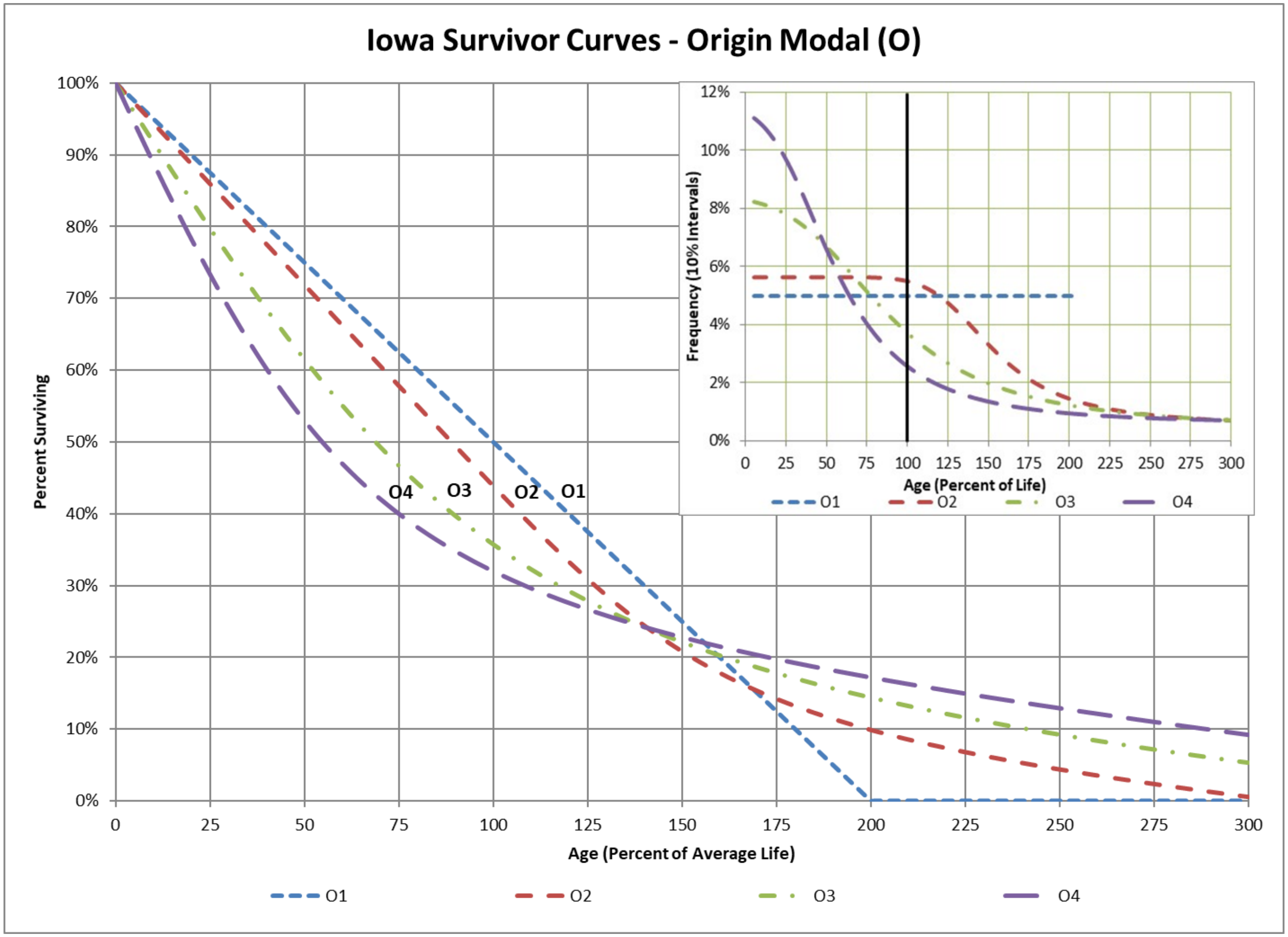


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[10] Engineering Valuation and Depreciation[11] and Depreciation Systems[12].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[10] Anson, Winfrey & Hempstead, supra note 7
[11] Anson, Winfrey & Hempstead, supra note 7
[12] Wolf & Fitch, supra note 2

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					**Placement Band 2003-2017**
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

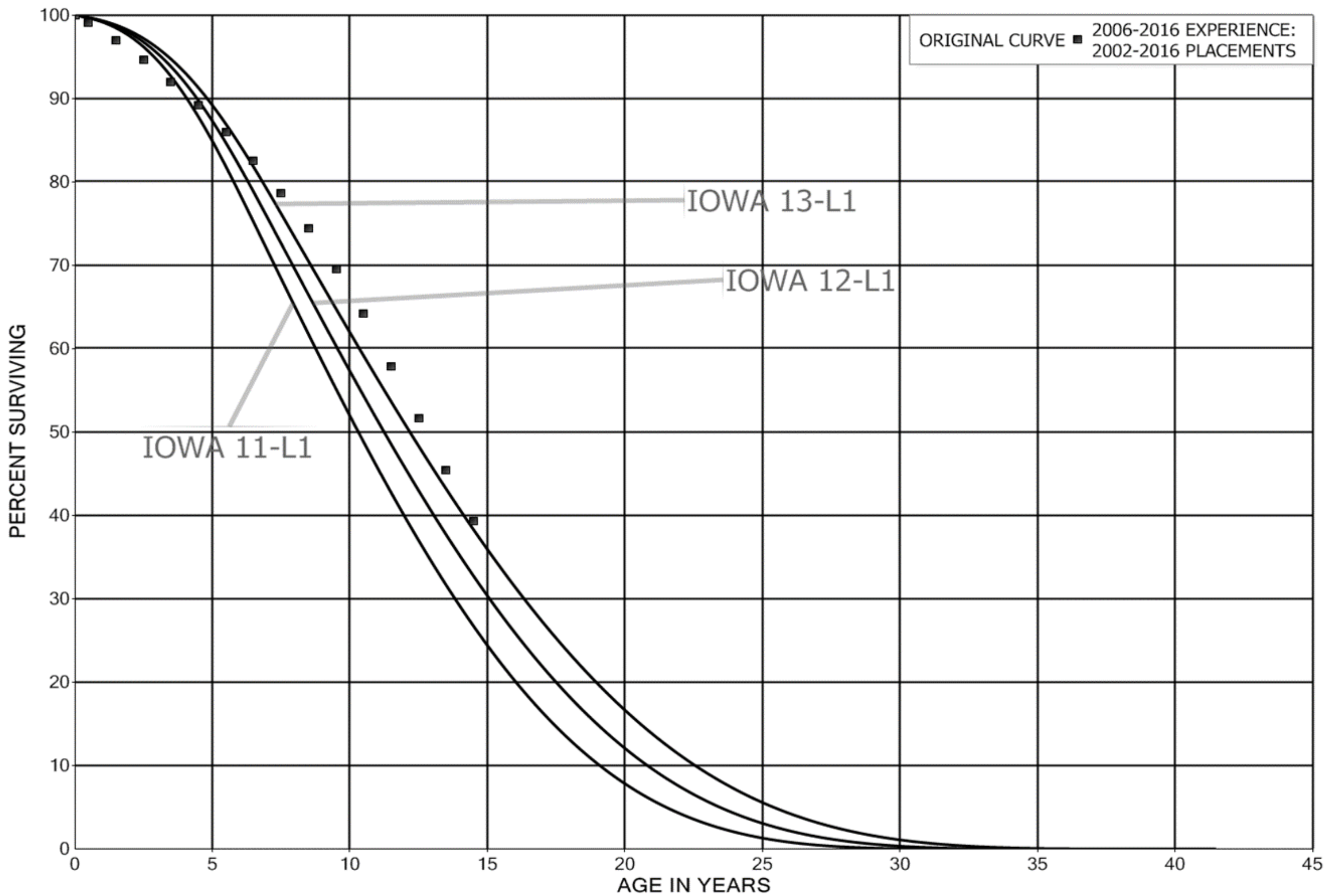


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

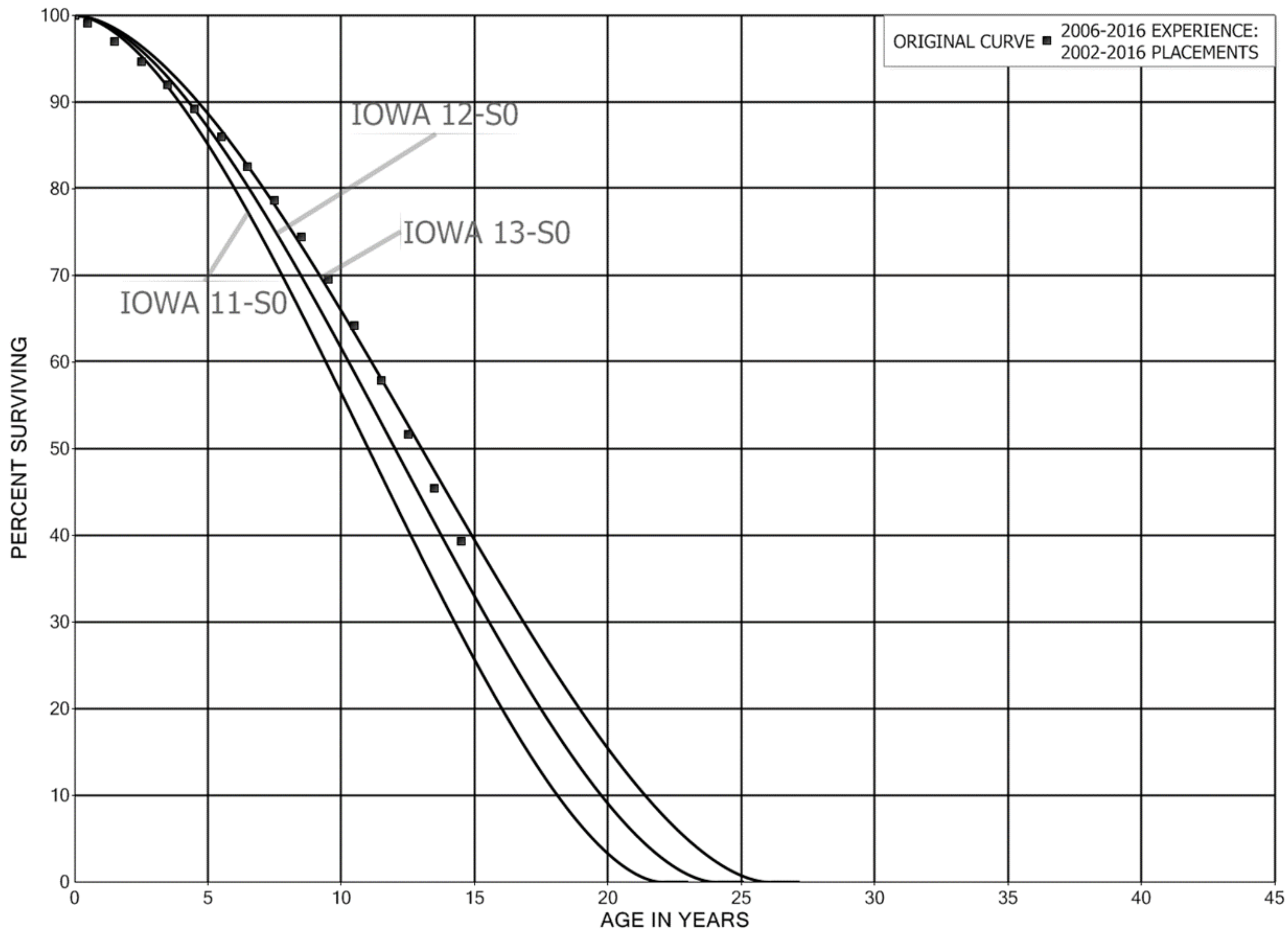


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

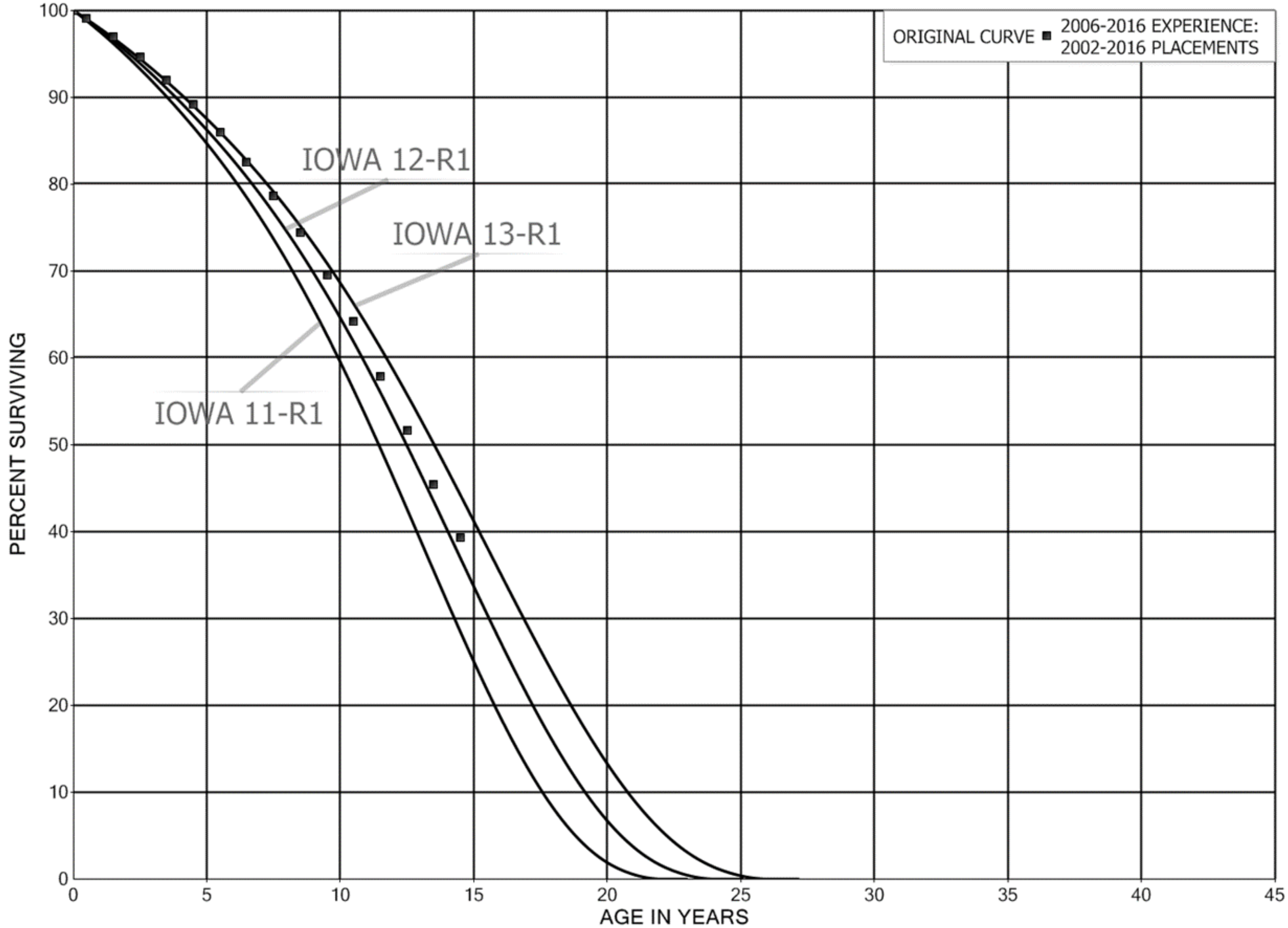
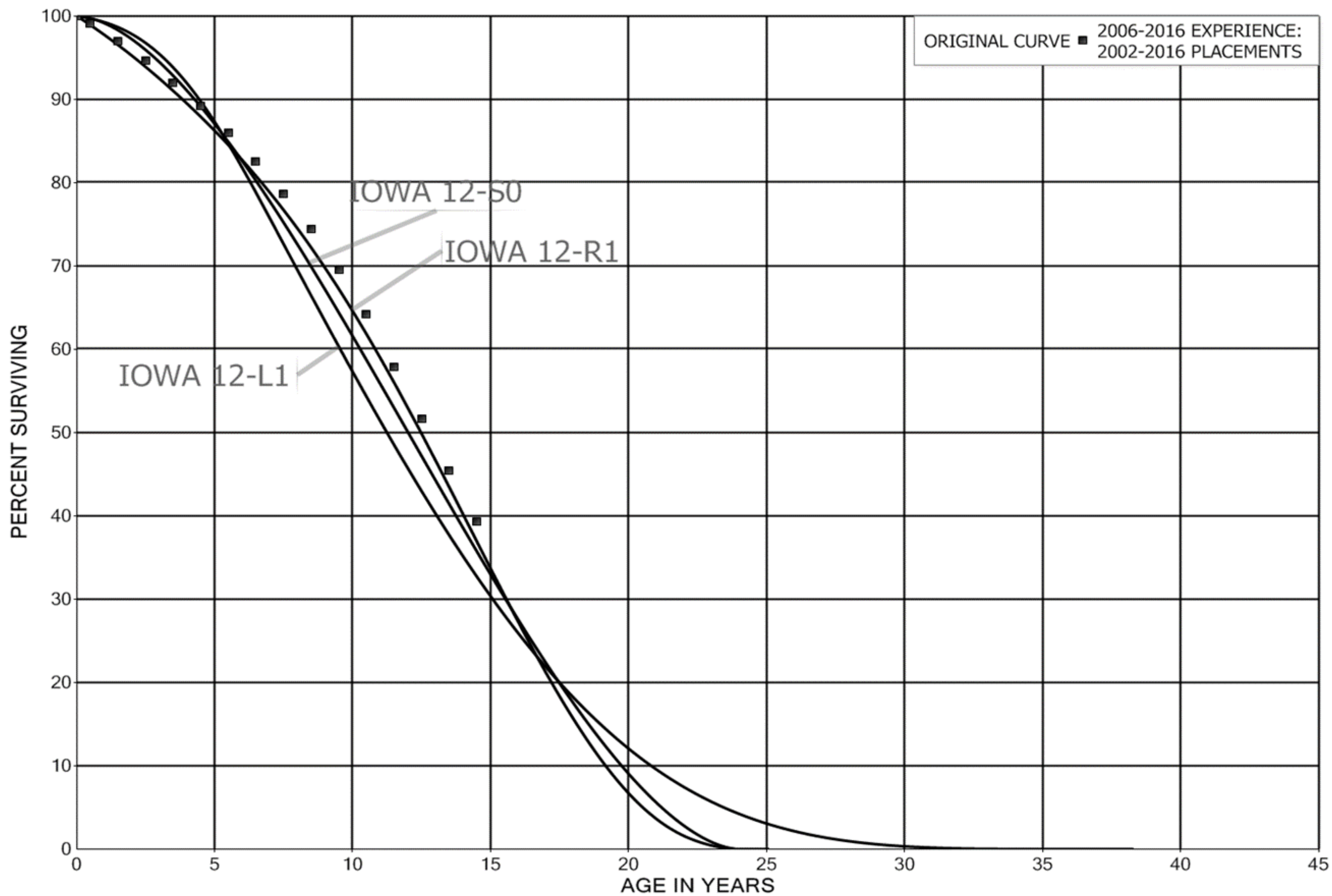


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to Canadian peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account. Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated are usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to Canadian peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and Canadian peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
FUEL AND PURCHASED POWER ADJUSTMENT
E8760 ALTERNATIVE ENERGY ALLOCATION METHOD
PROJECTED 2027

			Class Allocation 2/					
Fuel and Purchased Power Cost	Integrated System	Allocation to North Dakota 1/	Residential	Small General Service	Large General Primary	Large General Secondary	Lighting Primary	Lighting Secondary
Energy								
Accounts 501 Coal and 547 Gas	$42,205,450	$30,273,767	$11,539,322	$1,331,524	$5,618,609	$11,610,687	$263	$173,362
Account 502 Reagent	3,007,060	2,156,950	822,156	94,869	400,315	827,240	19	12,351
Account 555 Energy	23,627,470	16,947,871	6,459,948	745,414	3,145,412	6,499,898	147	97,052
Account 575 Market Admin.	499,177	358,058	136,479	15,748	66,453	137,324	3	2,051
Total Energy	$69,339,157	$49,736,646	$18,957,905	$2,187,555	$9,230,789	$19,075,149	$432	$284,816
Demand								
Accounts 555 Demand and 547 Pipeline Charges	$4,816,649	$3,560,708	$1,384,071	$168,178	$516,244	$1,466,490	$27	$25,698
Less:								
Wholesale Sales Revenue	$6,726,230	$4,824,692	$1,767,684	$214,791	$936,396	$1,872,948	$50	$32,823
Sale of RECs Revenue	1,448,357	1,033,138	378,524	45,994	200,516	401,065	11	7,028
Total Revenue	$8,174,587	$5,857,830	$2,146,208	$260,785	$1,136,912	$2,274,013	$61	$39,851
Net Fuel and Purchased Power Costs	$65,981,219	$47,439,524	$18,195,768	$2,094,948	$8,610,121	$18,267,626	$398	$270,663
Kwh Retail Sales	2,977,629,000	2,135,839,000	780,956,726	94,894,044	418,003,236	827,461,794	22,347	14,500,853
System Cost per Kwh	$0.02216	$0.02221	$0.02330	$0.02208	$0.02060	$0.02208	$0.01781	$0.01867

1/ Energy is allocated on Kwh sales and demand and pipeline are allocated on Allocation Factor No. 15 - Integrated System 12 Month Peak Demand.
2/ Energy is allocated using E8760 Class Ratios per Kwh sales. Demand and pipeline charges are allocated on Allocation Factor No. 2 - Coincident Peak Demand
Revenues are allocated on Kwh sales at generation.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA
CALCULATION OF E8760 FACTOR
CASE NO. PU-26-___

	Residential	Small General	Large General Primary	Large General Secondary	Lighting Primary	Lighting Secondary	Total
Hourly Marginal Energy Costs x Hourly Loads	$35,429,794	$4,088,445	$17,247,919	$35,645,935	$815	$532,207	$92,945,115
Kwh Energy at Generator	849,567,823	103,230,969	450,041,705	900,158,510	24,310	15,774,929	2,318,798,246
Load-Weighted Marginal Energy Costs/Kwh	$0.04170	$0.03960	$0.03833	$0.03960	$0.03352	$0.03374	$0.04008
Class Ratio	1.0404	0.9880	0.9563	0.9880	0.8363	0.8418	1.0000
MWh Energy at Generator	849,568	103,231	450,042	900,159	24	15,775	2,318,799
Load-Weighted Marginal Energy Costs/Kwh	$41.70	$39.60	$38.33	$39.60	$33.95	$33.74	$40.08
Class Ratio	1.0404	0.9880	0.9563	0.9880	0.8471	0.8418	1.0000

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony

of

Ronald J. Amen

June 30, 2026

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

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. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A.

Q. Have you previously testified before the North Dakota Public Service Commission ("Commission")?

A. Yes. I provided expert witness testimony on behalf of Montana-Dakota in Case Nos. PU-20-379, PU-22-194, and PU-23-341.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional 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 provide a list of the exhibits and schedules supporting your testimony.

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

- Exhibit No.____(RJA-1), Revenue Requirement Impact
- Exhibit No.____(RJA-2), Customer Total Bill Impact
- Exhibit No.____(RJA-3), Estimated Residential Bill Increases

II. COST OF SERVICE STUDIES

Q. What are the purposes of cost-of-service studies?

A. The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. In other words, a cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

The cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. The cost analyst must rely on who causes costs and how those costs are recovered within a class of customers as the basis for determining rates that result from the cost of service study.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

III. PRINCIPLES OF COST CAUSATION

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool for ratemaking. 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. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term "on average" is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for "typical" customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

For rates to be efficient, the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods

2. Non-Coincident Peak ("NCP") Methods

3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

Table 1

Cost Allocation Methods Summary

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the Montana-Dakota cost of service study?

A. A combination of a) the 12-CP demand method for production and transmission costs, and b) the class NCP demands at the generation, and distribution levels were used in developing the Montana-Dakota COSS.

IV. THE COST OF SERVICE STUDY PROCESS

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution
- General, Common, and Intangible

Each function is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system.

In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly, plant and expenses caused by individual customers.

The <u>General, Common, and Intangible</u> function includes office buildings and equipment, vehicles, materials and supplies, the Customer Care and Billing (CC&B) system, and other engineering and communications software systems.

Q. Please describe the cost classification step.

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand-related and the portion that is customer-related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. <u>*Demand*</u> costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand, and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expenses.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes. For example, as mentioned earlier, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process.

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is the allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines, and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and are adjusted to equal system peaks. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors.

Q. How do the principles and processes you have explained pertain to fixed costs and variable costs?

A. In the utility ratemaking context, fixed costs include all costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

V. SELECTION OF CLASS COST OF SERVICE FOR MONTANA-DAKOTA

A. Production and Transmission Plant

Q. Please describe the nature and characteristics of Montana-Dakota's Production and Transmission plant.

A. The investment in the production and transmission plant is included within the integrated system, which was allocated on the 12 CP demand allocator for each class.

Q. Is there a test or analysis used in the utility industry to determine the appropriateness of the allocation method for production and transmission assets?

A. Yes. 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."[1] 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):

<u>Test No. 1 – On and Off-Peak Test</u>: 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

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

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 (2018-2025). Montana-Dakota meets all three FERC tests for using 12 CP for five out of the eight years. For 2020 and 2022 Montana-Dakota meets two of the three tests. Therefore, 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 below shows the results of the Montana-Dakota's FERC 12-CP test.

Table 2

FERC 12-CP Tests*

Use 12 CP if:	Peak - Off-Peak % Difference <=19.0%	Low/Annual Peak Ratio >=66.0%	Avg/Annual Peak Ratio >=81.0%
2025	17.7%	69.3%	85.6%
2024	21.3%	61.8%	80.5%
2023	12.6%	78.2%	87.9%
2022	15.0%	63.9%	85.5%
2021	17.6%	68.2%	83.8%
2020	18.2%	62.5%	84.1%
2019	12.9%	74.5%	89.5%
2018	16.2%	72.0%	86.8%

*Per 123 FERC ¶ 61,047 at 61,249

B. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant.

A. The Montana-Dakota system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer, but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes, and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity. For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer.

Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. When customers who have common load characteristics, “homogeneous” load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 (Poles, Towers & Fixtures), 365 (Overhead Conductor), 366 (Underground Conduit), 367 (Underground Conductor), 368 (Line Transformers), 369 (Services), 370 (Meters), and 373 (Street Lighting), either all or a portion of the costs are customer related because customers cause them. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customer’s own load characteristics. The service line is dedicated to the customer to meet the load of the customer's premise. Services are dedicated to a customer, and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex, and the cost of meter sets increase. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The concept of a minimum system assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

C. Minimum Distribution System

Q. Is the method used by the Company to determine a customer cost component of a distribution system a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-size 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 hypothetical 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. Both methods are acceptable to the 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").

Q. Of the two methods, which has Montana-Dakota used to determine its minimum distribution system?

A. 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 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. Montana-Dakota has used this approach in prior COSS studies in North Dakota and its other jurisdictions.

Q. Does the one-mile minimum system approach a provide a reasonable representation of customer-driven distribution system costs?

A. Yes. The one-mile-of-circuit approach attempts to construct 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 to creating a hypothetical one-mile circuit is a realistic proxy for circuits in Montana-Dakota's service territory.

Q. How does Montana-Dakota apply the one-mile minimum system methodology in its COSS study?

A. Montana-Dakota combines its customer and demand portions of Account Nos. 364-367 based on weighted asset values for each account to derive single percentages for the combined accounts.

Q. How does Montana-Dakota separate the two classification components for Account No. 368, line transformers?

A. Montana-Dakota uses the zero-intercept regression analysis to determine the customer component of transformers. Specifically, the zero intercept costs were multiplied by the number of transformers at or below 50 kVA. The ratio of that amount to the total replacement cost of all transformers was 55.48%, which was used for establishing the customer component of transformer plant.

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. Line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis.

The results of Montana-Dakota's analyses appear in Table **3** below. The values for the weighted average of FERC accounts 364-367 and FERC account 368 are inputs to the COS model. Note that, as with other utilities, FERC account 366, underground conduit, is assumed to have the same classification properties as underground conductors.

Table 3

Minimum Size/Minimum Intercept Results

FERC A/C	Account Name	Customer	Demand
364	Poles – Primary	56.4%	43.6%
365	Overhead Conductors	68.5%	31.5%
367	Underground Conductors	56.6%	43.4%
364-367	Weighted Average	58.0%	42.0%
368	Line Transformers	55.5%	44.5%

D. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer-related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer-related, all of the associated O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores, tools, and equipment. Fourth, a portion of administrative and general expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs, but pension and benefits cost and other items related directly to employee costs.

E. Distribution Plant

Q. What method does Montana-Dakota employ to allocate demand-related distribution costs?

A. Montana-Dakota allocates demand-related distribution costs primarily by reference to class shares of noncoincident peak (“NCP”) demand. Load research reveals each class’s single maximum level of consumption over the course of a year. The “One NCP” allocator is simply each class’s share of the sum of these values. (The “One” signifies a single annual maximum value). Investment in distribution costs occurs in response to the increase in peak demands of customers on individual feeder lines; such peak demands do not necessarily correspond with the timing to system peak demands. Accordingly, measuring each customer class’s peak and then estimating the class’s share in the sum of the peaks across all classes is a reasonable way to judge responsibility for demand-related cost causation applying to distribution investment.

The Montana-Dakota COSS model uses two NCP allocators, one applicable at the generation level and another at the secondary service level. The “NCP – Generation Level” allocator is based on the peak demands of all customers and allocates demand related costs associated with land, station equipment, poles, conductors, and conduit. The “NCP – Secondary Level” allocator is based on the peak demands of secondary distribution customers and allocates demand-related line transformer costs.

Q. What is the underlying evidentiary basis for Montana-Dakota’s One NCP allocators?

A. Montana-Dakota has developed load research data for its customer classes. For each class, Montana-Dakota developed sample usage, coincident peak, and class non-coincident peak data for calendar 2025, then scaled the values based on billed kWh. This results in demand values that preserve observed load factors of the load research sample. Load research results are available to Montana-Dakota for about 93% of jurisdictional load. The classes making up the remaining 7% of load were each matched to a class for which interval data are available. Demand values were calculated that produce load factors identical to the class with which each class lacking interval data was matched. For the test year (2027), Montana-Dakota produced kWh forecasts and demand values that yielded load factors identical to those of the historical data.

Q. In your opinion is Montana-Dakota's load research process reasonable?

A. Yes. This application of load research data to generate demand-related allocators is standard practice; it is consistent with other utilities' practices.

Q. How does Montana-Dakota allocate customer-related distribution costs?

A. Montana-Dakota uses allocators based on customer numbers, weighted by costs for certain cost categories, for various types of assets and expenses. The Company develops several customer-related allocation factors: customer numbers; customer less outdoor lighting; customer meters, weighted by an index of meter costs; customer service drops, weighted by service cost; customer transformers, weighted by transformer cost; and customer accounts, weighted by the cost of customer support. The Company's forecasts of test year customer numbers and meter numbers underpin these allocation factors.

F. Other Allocation Factors

Q. Please describe other types of allocation factors within the COSS.

A. There are numerous other allocation factors in the COSS. 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 provisions for pension and benefits and post-retirement are allocated on O&M excluding fuel and purchased power. General, Common, and intangible plant investments are allocated on Production, Transmission and Distribution plant. General, Common-Intangible-CC&B and PCAD are allocated on Total Customers. Distribution Computer Hardware, Software, and Communications Equipment are allocated on all other Distribution Plant excluding land.

G. Summary of the Allocated Cost of Service Study

Q. Please summarize the results of the recommended cost of service study.

A. The following Table 4 provides a high-level summary of the results of the COSS. Table 4 shows the rate of return for each rate class based on current rates as well as the overall system return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

Table 4

Rate of Return and Revenue Excess/(Deficiency) by Rate Class[2]

Rate Class	Rate of Return By Class	Revenue Excess or (Deficiency)
Residential	2.970%	(24,290,231)
Small General	5.000%	(1,800,818)
Irrigation	(1.433%)	(98,185)
Large General Service - Primary	8.340%	179,123
Large General Service - Secondary	8.042%	134,939
TOD Large General Secondary	3.235%	(286,487)
Space Heating	(3.331%)	(5,902,552)
Small Municipal	3.060%	(96,075)
Public Lighting - Secondary	7.269%	(72,825)
Municipal Pumping - Primary	4.648%	(238,208)
Municipal Pumping - Secondary	9.048%	80,060
Outdoor Lighting	4.756%	(118,824)
IT Demand Response	11.887%	226,080
Special Contracts	-	(2,210,534)
SYSTEM TOTAL	**4.695%**	**(34,494,537)**

[2] Rate of Return by Class Statement K pp. 1-15; Revenue Excess/(Deficiency) by Rate Class at Statement L, Schedule L-1.

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, stand-alone costs, and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Montana-Dakota taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in Section VII of this testimony.

Q. Please describe the COSS schedules attached to this testimony.

A. There are three schedules attached to this testimony that provide further details of the COSS that include the following information: They are:

- Statement K, Cost of Service by Component, consists of 15 pages and presents a summary of each rate class's projected 2027 Test Year rate base, the revenue requirements necessary to achieve the requested rate of return, and the rates of return under current rates.
- Statement K, Schedule K-1, consists of 90 pages and presents the Rate Base, Revenue, and Expenses by Class at Current Rates. This schedule provides the detail by cost and revenue component resulting in the projected rate base and class rates of return at current rates.

- Statement K, Schedule K-2, Allocation Factor Report, consists of 16 pages and shows the development of the factors used to allocate costs to the rate classes.

Q. Please explain the COSS information contained in Statement K.

A. Statement K provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the projected rate of return of 7.996 percent were to be earned for the demand – production and transmission, demand – distribution, energy, and customer cost components of each rate schedule. Statement K also shows the system total rate of return before increase as well as the individual rate schedule rates of return before increase.

Statement K, Schedule K-1, is a report of the projected 2027 rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in Statement K, Schedule K-2.

The COSS is based on a projected 2027 average test period for North Dakota electric operations sponsored by Company witness Mr. Davison.

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3]

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by electric power producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the electric utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

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[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than service value, consumers will not purchase the service.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally."

Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices to be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $34.49 million to its customer classes.

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

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost ratio for each class was equal to 1.00 (Unity), as shown in Statement L, Schedule L-1, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made with consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-fuel revenues (see *Scenario A, Equal Percentage Increase*, in Statement L, Schedule L-1). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Montana-Dakota's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Montana-Dakota's class revenue proposal.

A third option was to limit the increase to customer classes above parity to receiving a revenue increase equal to 0.75 of the system average increase, or 18.090%, and cap the maximum increase to any class at 48.239%, with the balance of the increase going to the Residential class. Classes where an increase between 18.090% and 48.239% would bring them to parity were brought to parity. This option would mitigate the divergence from parity for those classes above parity, while making reasonable movement towards parity for the other classes[4] (see *Scenario B*, *Minimum Class Increase of 75% of System*

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[4] Special contact customers were limited to the same percentage increase as Rate 30, Large General Service, Primary.

Average, Maximum of 200% Increase, Remainder to Residential, in Statement L, Schedule L-1).

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes: Residential Service (Rate Schedule 10), Small General Service (Rate Schedule 20), Irrigation Service (Rate Schedule 25), Large General Service (Rate Schedule 30), TOD Large General Service (Rate Schedule 31), Space Heating (Rate Schedule 32), Small Municipal Service (Rate Schedule 40), Public Lighting Service (Rate Schedule 41), Municipal Pumping Service (Rate Schedule 48), Outdoor Lighting Service (Rate Schedule 52), Interruptible Demand Response Service class (Rate Schedule 38) and Special Contact customers, as shown in Statement L.

In the case of the Residential Service class, the revenue adjustment ensures that their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve its revenue to cost ratio from 0.72 to 0.93.

The Small General Service (0.84), TOD Large General Service (0.71), Small Municipal Service (0.72), and Municipal Pumping Service Primary (0.79) classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.996%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity.

The maximum revenue increase of 48.239% is proposed for the Irrigation Service, Space Heating, and Outdoor Lighting Service customer classes resulting in revenue to cost improvement ratio of 0.45 to 0.67 for Irrigation Service, 0.32 to 0.48 for Space Heating, and 0.65 to 0.96 for Outdoor Lighting Service.

The 0.75 times system average revenue increase of 18.090% is proposed for Large General Service Primary and Secondary, Public Lighting Service, Municipal Pumping Secondary Service, and Interruptible Demand Response Service. The COSS results for the remaining customer classes indicate their respective class rates of return are near or 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 decreases 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), as shown in Statement L, Schedule L-1, under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes, or alternatively, exempting these classes from revenue increases. Instead, the proposed respective revenue adjustments of 75% of the system average increase to eligible customers will mean these classes will be slightly higher than their current parity ratio levels relative to unity. The resulting revenue to cost ratios increase from 1.02 to 1.21 for Large General Service – Primary, 1.00 to 1.18 for Large General Service – Secondary, 0.90 to 1.06 for Public Lighting Service, 1.06 to 1.26 for Municipal Pumping Secondary Service, and 1.26 to 1.49 for Interruptible Demand Response Service. The Special Contract customers were limited to the same revenue increase as the Large General Service Primary class, or 18.090%.

After these class increases to base rates are made, there remains a balance of $18,343,305 that was allocated to the residential rate class resulting in a 29.895% revenue increase.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

Statement L, Allocation of Revenues, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each tariff rate schedule. The proposed revenue increase by rate schedule and corresponding percentage is also shown.

The allocation of the total revenue increase of $34.49 million to the respective rate schedules is presented in Statement L, page 2. The target revenue increases as a percentage of total class revenues, including fuel costs, range from 23.3% to Residential, 16.7% to Small General, 14.1% to Large General, 13.1% to Public Lighting, 15.0% to Municipal Pumping, and 36.7% to Outdoor Lighting.

VIII. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. Montana-Dakota has proposed to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules, as shown on Schedule L:

- Residential Service (Rates 10, 13 & 16);
- Small General Service (Rates 20 & 26);
- Irrigation Service (Rate 25);
- Large General Service (Rates 30, 31, 32 & 38);
- Municipal Service (Rate 40);
- Public Lighting (Rate 41);
- Municipal Pumping (Rate 48); and
- Outdoor Lighting (Rate 52)

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement L, the Basic Service Charge under Residential Rate 10 is proposed at $0.988 per day, which reflects an average monthly charge of $30.05 as shown on Exhibit No. ___(RJA-3), page 1, an increase of approximately $14.81[5] per month from the currently effective charge. This proposed charge reflects the $30.04 customer component identified in the embedded class cost of service as shown on Statement K, page 1. The Basic Service Charge is billed on a daily basis to avoid prorating the monthly charge when customers are in service for less than 30 days, on average, or when a billing period extends beyond a 30-day average. A typical residential customer, averaging approximately 800 Kwh monthly usage will see a monthly increase in

[5] Residential proposed Basic Service Charge monthly average of $30.05 less current Basic Service Charge monthly average of $15.24 equals $14.81

their electric service bill of approximately $19.00 as shown on Exhibit No. ___(RJA-3), page 1.

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 are provided for each rate schedule on pages 6 – 23 of Statement L. A summary of the proposed charges for each rate schedule is provided on Statement L pages 4 and 5.

Q. Was there an exception to the process that you just described for any Rate Schedule?

A. Yes. While Rate 32 is primarily a space heating rate, the Availability provision of the rate does allow for heat pump use and packaged roof-top heating/cooling units, which operate in the summer in cooling mode. Therefore, Montana-Dakota determined that the summer demand charge for Rate 32 should be equivalent to the Rate 30 demand charge. The proposed Rate 32 summer demand charge was matched to the Rate 30 demand charge, and the secondary energy charge was increased by the percentage increase allocated to the Rate Class.

Q. Please further discuss your proposal to increase the Basic Service Charge component of the previously identified rate schedules.

A. The Basic Service Charge component of each rate schedule has been set at or near the cost per customer component identified in the embedded class cost of service study. As shown on Schedule K-1, the customer component reflects those costs that vary by the number of customers served in each rate class. This includes the investment in meters and services that directly serve each individual customer, and a portion of the investment in poles, overhead and underground conductors, and line transformers. Through the COSS, these facilities have been determined to be associated with the minimum investment necessary to provide service to a customer regardless of the energy or peak load requirements of that customer.

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 to minimize intra-class subsidies and provide customers with the appropriate economic price signals. Increasing the Basic Service Charge to the amount identified as necessary to recover customer-related fixed costs does not provide a disincentive to use energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;

- Mitigating the impact abnormal weather has on the Company's ability to recover fixed cost;
- Residential customers' bills will be more stable as approximately 24.2 percent of the total bill will be fixed each month and not dependent on changes in weather; and
- Provides a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less energy than average.

Q. Do increases in Basic Service Charges, such as those proposed by Montana-Dakota, discourage conservation?

A. No. For example, under the Company’s proposed increase to its Residential Basic Service Charge, customers will continue to have a financial incentive to pursue energy efficiency measures. As depicted in Exhibit No. ___(RJA-3), the portion of the average residential customer’s annual bill attributable to the proposed Basic Service Charge is approximately 25% of the total bill[6]. The effect of raising the proposed Basic Service Charge by $0.487 per day, the equivalent of $15.10 per month in January, the month in which the most electricity is typically consumed by residential customers, is only 20% of the total bill. This is a small amount. The energy and fuel charges are 63% of the customer’s bill in January, which continues to provide a strong economic price signal that may influence the customer's ongoing consumption decisions. In my opinion, the

[6] Residential proposed Basic Service Charge monthly average of $30.05 divided by proposed Residential average monthly bill of $124.26, equals 24.18%.

relatively small amount of fixed costs added to the Basic Service Charge that would otherwise be recovered in the volumetric Energy Charge will not materially affect a customer's decision to use more or less energy.

By recovering its fixed distribution costs in the Residential Basic Service Charge, the Company will be able to continue promoting energy efficiency and conservation for its customers while moderately reducing the real threat of margin losses due to declining sales per customer.

Q. Does a volumetrically weighted rate design provide the most appropriate prices signals to customers related to energy consumption?

A. No. A volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the electric utility's system; and (4) needlessly inflate bills in the peak summer and winter months, when customers face the greatest pressure on their household budgets from utility bills. Montana-Dakota's rate design proposal to increase the level of its Basic Service Charges moves in the right direction to minimize these undesirable effects and best aligns the price signals to customers with the underlying costs of providing electric delivery service.

In summary, a Basic Service Charge provides increased bill stability for customers and increased revenue stability for the Company.

IX. OVERALL RATE AND CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared a bill comparison for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Residential customer using approximately 800 Kwh per year is shown on page 1 of Exhibit No.___(RJA-3), Rate 10 Residential Bill Comparison for electric service. The average monthly increase for this residential customer under the Company's proposed rate design is approximately $19.00 or 18.2%.

Q. Has Montana-Dakota prepared overall bill impacts by Rate Class?

A. Yes. Due to the effect of moving transmission project costs currently being recovered in the Company's Transmission Cost Adjustment (Transmission Rider TCA) into base rates as discussed by Mr. Davison, the Company is presenting two different views of the overall bill impacts resulting from this case. This first view is the overall increase in rates resulting from the Company's $34.49 million revenue requirement increase or 18.1% increase as shown in Exhibit No. ___(RJA-1). However, as the Company's revenue requirement reflects the inclusion of revenue related to the transmission project revenue, Exhibit No. ___(RJA-1) also includes the additional $8,726,307 increase in base rates resulting from the movement of transmission projects into base rates, resulting in a Rate Design increase of $43,215,594.

The second view is the net bill increase by rate class as shown in Exhibit No. ___(RJA-2). This expanded view further considers the net change in the TCA rates as well as the overall total bill impact, taking into consideration the Company's other two riders that are not a part of this case and are not changing. From this view, the overall net increase in a customer's total bill is comprised of both the increase in the Company's base rates of 18.1 percent and the net decrease in the Company’s TCA rates of 3.7 percent for a net overall bill impact of 14.5 percent.

Q. Does this conclude your direct testimony?

A. Yes.

Ronald J. Amen

CHAIRMAN & EVP

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska, Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

45

PROFESSIONAL ASSOCIATIONS

American Gas Association

Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis, Litigation Support, Regulatory Support, Strategy, Utility operations

EXPERIENCE AND SELECTED ACCOMPLISHMENTS

REGULATORY POLICY, STRATEGY AND ANALYSIS

California Independent System Operator (2023, 2005 – 2026)

Atrium was engaged by the California Independent System Operator (CAISO) to provide consulting support for evaluation of cost recovery proposals related to transmission infrastructure development. The engagement included a review of developer contracts and force majeure claims, with a focus on post-COVID cost overruns and their implications for ratepayer impact and regulatory compliance. Atrium reviewed historical precedents and evaluated the validity of force majeure assertions under FERC and CAISO protocols. The team supported the development of testimony, interrogatories, and settlement materials, and provided post-filing support for regulatory proceedings. Atrium also analyzed contract cost estimates and deliverable schedules, coordinated with CAISO procurement and legal teams, and reviewed transmission plant construction indices to inform escalation assumptions and capital budgeting. The engagement included analysis of Handy-Whitman index trends, cost-of-service statements, and operation and maintenance workpapers to support rate case filings and interconnection cost recovery. Atrium’s work contributed to CAISO’s ability to assess developer claims, refine procurement strategies, and ensure alignment with regulatory expectations. The engagement was governed by a formal consulting agreement and executed through multiple phases, including contract review, cost analysis, testimony development, and post-filing implementation support.

Atrium also provided expert rebuttal testimony to respond to the transmission developers fixed price transmission development agreement. Atrium's testimony focused on the customary meaning and use of pricing and inflation-related terms commonly used in contracts and bids. The scope includes a review of the project developers bid materials and the executed Approved Project Sponsor Agreement (“APSA”) and its associated Amendments, to evaluate and interpret the relevant contract terms and provide an expert opinion on how these terms are typically drafted, interpreted, and understood in practice, including the treatment of inflation adjustment provisions.

Los Angelos Department of Water and Power (2025 – Present)

Atrium partnered with two other consulting firms to analyze and review the Department's current operational policies and procedures related to natural gas supply procurement processes and to develop and present best practices recommendations to LADWP senior management and LADWP personnel. The analysis and recommendations will include, but not be limited to, identifying regulatory risks and mitigation strategies related to a) the Natural Gas Procurement process used by LADWP on intrastate and interstate pipelines and b) the procurement of Gas for the Intermountain Power Project (IPP) by LADWP acting as the Operating Agent.

Atrium's engagement included the development of comprehensive training modules on best practices related to gas procurement, risk management, nominations, balancing, settlement, regulatory compliance and FERC oversight, which encompasses ten training modules delivered over a period of 3 months.

FortisBC Energy, Inc. (2016 – 2018, 2021-2022)

Performed an overall review of the client’s Transportation Service Model. Analyzed the client’s various midstream transportation and storage capacity resources used in providing balancing of transportation customers’ loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers’ imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc’s acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client’s Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms were assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

McDowell, Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Manitoba Hydro (2024-2025)

Retained by the client to provide a financial benchmarking framework that will ensure its financial health, its ability to achieve long-term financial targets, and will support organizational decision making. Reviewed regulatory jurisdictions in Canada and the U.S. with similarly situated provincially or publicly owned electric utilities to gain an understanding of how each regulatory jurisdiction uses financial metrics in rate setting, i.e., which metrics are relied upon and how do those metrics factor into the determination of authorized rates. Review included at least one Crown or municipal utility in each Canadian province, U.S. public power hydroelectric utilities, and opportunistically brought in relevant research from other sectors. Short-listed a group of financial metrics used to assess financial health for modeling to test financial outcomes of metrics and targets for consideration by Executive Team (in progress).

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight into the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021-2022)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Philadelphia Gas Works PGW (2023, 2024-2025)

Mr. Amen led an Atrium team engaged by PGW to review the mechanics, input data, billing controls, and weather trends surrounding PGW's Weather Normalization Adjustment ("WNA") formula to understand the factors that contributed to the abnormally high WNA charges in June 2022. Atrium's review identified structural factors inherent in PGW's WNA mechanism that may have contributed to the anomalous WNA amounts billed to customers in June 2022. Mr. Amen filed testimony with Atrium's findings and recommendation in the pending general rate case before the Pennsylvania Public Utility Commission. Mr. Amen provided expert testimony in PGW's 2024 general rate proceeding supporting the continuation of the WNA, supplemented by the addition of a Revenue Normalization Adjustment ("RNA") mechanism. (Case pending)

Public Service Company of Colorado (Xcel) (2024)

Mr. Amen was engaged to provide expert testimony presenting and supporting the Company's proposed Revenue Stability Mechanism ("RSM"). The RSM is a total revenue decoupling mechanism intended to separate the Company's revenue from the volume of gas it sells to help support Colorado's state decarbonization goals. The Colorado Senate Bill 21-264 directed gas utilities to submit "Clean Heat Plans" to reduce carbon dioxide and methane emissions toward Clean Heat targets in specific years. Potential emissions reduction measures include energy efficiency, biomethane, hydrogen, recovered methane, beneficial electrification of customer end users, and leak detection, among others.

Potomac Electric Power Company (PEPCO) (2024)

Mr. Amen led an Atrium team engaged by PEPCO on behalf of services requested by the Public Service Commission of the District of Columbia ("DC Commission") conducted an independent audit of PEPCO's Administrative Charge associated with its Standard Officer Service ("SOS"), in accordance with the District of Columbia Public Service Commission's directives. The audit evaluated the processes, procedures, mechanics, and internal controls supporting the SOS administrative charge to confirm that costs were accurate, appropriate, and consistently applied across customer classes. Atrium demonstrated a strong understanding of Pepco's SOS framework, including the structure and calculation of the administrative charge components. The review confirmed that the administrative charge was designed to recover incremental SOS-related costs, including uncollectibles, consultant and bidding expenses, transaction and billing costs, system costs, customer education, renewable procurement costs, and legal and regulatory expenses.

Atrium confirmed that SOS administrative charge rates were accurately reflected in tariff schedules and properly applied in customer billing through sample bill testing. We further evaluated PEPCO's internal control environment related to the SOS administrative charge, including the design and operation of Key Financial Controls ("KFCs"). Throughout the engagement, Atrium maintained regular coordination with the DC Commission and PEPCO, providing status updates and addressing issues as they arose. The execution of this audit reflected Atrium's unique combination of regulatory expertise, ratemaking knowledge, and accounting and audit experience.

Potomac Electric Power Company (PEPCO) (2022-2023)

Mr. Amen led an Atrium team engaged by Potomac Electric Power Company ("PEPCO") on behalf of services requested by the Public Service Commission of the District of Columbia (or the "DC Commission"), for comprehensive evaluation of the processes, procedures, mechanics, and internal controls surrounding PEPCO's Bill Stabilization Adjustment ("BSA"). Atrium provided independent audit services sought by the DC Commission. Specifically, our audit work included a) an independent evaluation of the timing, impact and magnitude of a billing determinant error that was identified during Formal Case No. 1156; b) independent confirmation that the current BSA processes and procedures were properly and timely executed as designed; c) independent confirmation that the existing controls surrounding the PEPCO BSA were properly and timely executed; d) independent identification of any recommended processes or procedural improvements, as well as any recommended changes in existing internal controls or new internal controls; and e) independent comprehensive review of PEPCO's BSA deferral balances by customer class, with an overall determination of the breakdown of BSA deferral balances by key drivers for each customer class. Atrium's audit report was submitted to the DC Commission and was subject to a stakeholder comment period before finalization.

Summit Natural Gas of Maine, Inc. (2022 - 2023)

Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness testimony support for the utility's gas general rate case and multi-year rate plan before the Maine Public Utilities Commission. Responsibilities included determination of an optimal normal weather period for purposes of normalizing test year billing determinants, followed by the weather normalization process of determining a representative level of gas throughput for the Company's test year. The case resulted in an all-party settlement before the Maine PUC.

Black Hills Energy Arkansas (2021-2022, 2023-2024)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for two of the utility's gas general rate case before the Arkansas Public Service Commission. The cases resulted in settlements before the Arkansas PSC.

Until Electric System, Northern Utilities, Fitchburg Gas & Electric (2021-2022, 2023-2024)

Mr. Amen provided allocated cost of service ("ACOSS"), marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

For Until affiliate, Fitchburg Gas & Electric, Mr. Amen conducted an ACOSS to determine the embedded costs of serving the Company's gas distribution customers and support its rate design efforts in its base distribution rate proceeding before the Massachusetts Department of Public Utilities. Sponsored expert witness support for the ACOSS, class revenue apportionment, proposed rate design, and bill impacts. Also sponsored the weather normalization and annualization of its billing determinants and a Marginal Cost of Service Study.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)

Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022 – 2023, 2024-2025)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission (MPSC) and North Dakota Public Service Commission (NDPSC). Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. The cases resulted in settlements approved by the respective Commissions.

Mr. Amen also represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Mr. Amen supported MDU electric general rate case filings in Montana and North Dakota (2022), including a marginal cost study in Montana, and allocated cost studies, revenue apportionment and rate design in both jurisdictions.

Mr. Amen supported gas general rate case filings in MDU's Idaho affiliate, Intermountain Gas (2022-2023, 2025) and Washington affiliate, Cascade Natural Gas (2024). Testimony support included a class level, design day load studies across the two utilities' temperature zones, using a combination of AMI penetration and monthly billing data, class allocated cost of service study, class revenue apportionment, and rate design.

Mr. Amen supported gas and electric general rate case filings in MDU's South Dakota service territory (2023), including gas and electric allocated cost studies, revenue apportionment and rate design.

Mr. Amen supported MDU gas cases in Montana and Wyoming (2024) and is currently supporting MDU electric cases in Montana and Wyoming filed in 2025.

Chesapeake Utilities Corporation (2020 – 2021, 2024-2025)

Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Mr. Amen is currently providing testimony support for Chesapeake Utility's Delaware general rate case (filed August 2024), including a Lead Lag study supporting cash working capital, determination of normal weather, cost of service and rate design principles, allocated cost of service results, revenue apportionment, and a modified version of a prior weather normalization adjustment (WNA) rider (Settlement pending).

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018, 2023, 2024 – 2026)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Ongoing work involves innovative rate programs and demand forecasting.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities.
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and

the State of Washington (WA), and the interpretation of such regulations in court decisions.

- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma related to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model, and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership (“EGNB”) general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB’s distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company’s general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company’s proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company’s decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility’s Minnesota electric system. Work included reconfiguring the company’s customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Potomac Electric Power Company (PEPCO) (2025)

Atrium supported the Public Service Commission of the District of Columbia in conducting a comprehensive management audit of Potomac Electric Power Company (Pepco), focusing on capital budgeting and forecasting, project management, financial performance, internal controls, and corporate governance. The audit examined Pepco's budgeting and forecasting processes, corporate governance, project management processes, and the quality of regulatory reporting. Interviews with key personnel informed assessments of internal control effectiveness, compliance culture, and ethical standards. Atrium evaluated entity-level controls and documented procedures related to monthly financial reviews, spreadsheet governance, and data reliability. The team coordinated with Pepco and Exelon staff to validate processes, controls, and clarify audit findings. The engagement culminated in a written report documenting a series of findings and recommendations addressing financial transparency, governance practices, and regulatory reporting, supporting the Commission's oversight objectives and informing future rate case proceedings.

Confidential Multi-State Gas Utility Client (2025)

Atrium Economics was engaged by the client to support operational planning and task allocation across its distribution and gathering systems in four state jurisdictions. The engagement included the development of work order tracking systems, task completion protocols, and compliance reporting frameworks for infrastructure repairs, meter changes, emergency response, and corrosion control. Atrium collaborated with the client's internal teams to classify work types by internal versus external execution, with specific attention to staffing constraints in its service areas.

The team analyzed historical and projected task volumes across multiple operating regions, and compiled performance metrics for leak repairs, damages, and compliance activities. Atrium supported the development of triannual and annual leak survey schedules, quarterly patrols, and valve inspection protocols, and provided recommendations for contractor engagement and third-party testing where internal resources were constrained. The engagement also included the preparation of distribution and transmission system maps, pipeline mileage summaries, and operating area profiles to inform resource allocation and strategic planning.

Atrium's work contributed to the refinement of the client's operational strategy and supported the development of defensible compliance documentation aligned with regulatory expectations. The engagement was executed through multiple phases, including task classification, data analysis, reporting development, and implementation support

Philadelphia Gas Works (2017, 2020, 2024)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Idaho Public Utilities Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Kentucky Public Service Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- South Dakota Public Utilities Commission
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Revenue Requirement Bill Impact
Case No. PU-26-_____

Rate Class	Projected 2027 Revenue at Current Rates 1/							
	Basic Servic Charge, Energy & Demand Revenue	Transmission Revenue	Fuel Revenue	Total Revenue	Revenue Requirement Increase	Revenue Requirement Impact	Rate Design Increase	Rate Design Impact
Residential Service	$57,696,510	$3,662,687	$17,462,192	$78,821,389	$18,343,340	23.3%	22,006,027	27.9%
Small General Service	9,001,571	445,053	2,121,831	$11,568,455	1,931,135	16.7%	2,376,188	20.5%
General Service	64,639,617	4,433,424	26,568,696	$95,641,737	13,507,512	14.1%	17,940,936	18.8%
Public Lighting	651,093	17,997	256,311	$925,401	121,048	13.1%	139,045	15.0%
Municipal Pumping	2,085,927	162,341	966,397	$3,214,665	480,884	15.0%	643,225	20.0%
Outdoor Lighting Service	213,647	4,805	68,414	$286,866	105,368	36.7%	110,173	38.4%
Total North Dakota Electric	**$134,288,365**	**$8,726,307**	**$47,443,841**	**$190,458,513**	**$34,489,287**	**18.1%**	**$43,215,594**	**22.7%**

1/ Statement F, Schedule F-1, Pages 4-5.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Customer Total Bill Impact
Case No. PU-26-_____

Rate Class	Projected 2027 Revenue 1/				Rider Revenue @ Current Rates				Total Revenue Including Riders Prior to Increase
	Basic Servic Charge, Energy & Demand Revenue	Transmission Project Revenue	Fuel Revenue	Total Revenue	Generation Rider 2/	Renewable Rider 3/	Transmission Expense Rider 4/	Total	
Residential Service	$57,696,510	$3,662,687	$17,462,192	$78,821,389	$2,553,729	$16,696,855	(1,007,433)	$18,243,151	$97,064,540
Small General Service	9,001,571	445,053	2,121,831	$11,568,455	310,303	2,028,834	(122,413)	$2,216,724	13,785,179
General Service	64,639,617	4,433,424	26,568,696	$95,641,737	3,135,167	24,365,810	(1,213,484)	$26,287,493	121,929,230
Public Lighting	651,093	17,997	256,311	$925,401	12,838	238,084	(4,929)	$245,993	1,171,394
Municipal Pumping	2,085,927	162,341	966,397	$3,214,665	122,828	892,219	(44,435)	$970,612	4,185,277
Outdoor Lighting Service	213,647	4,805	68,414	$286,866	3,428	63,564	(1,316)	$65,676	352,542
Total North Dakota Electric	**$134,288,365**	**$8,726,307**	**$47,443,841**	**$190,458,513**	**$6,138,293**	**$44,285,366**	**($2,394,010)**	**$48,029,649**	**$238,488,162**

Rate Class	Rate Design Increase	TCA Rider Revenue			Overall Net Proposed Increase	Total Net Proposed Revenue	Customer Total Bill Impact		
		Proposed TCA Revenue 4/	TCA at Current Rates	Net Increase in TCA 5/			Overall Bill Impact	Base Rate Bill Impact	TCA Bill Impact
Residential Service	$22,006,027	($1,007,433)	$2,655,253	($3,662,686)	$18,343,341	$115,407,881	18.9%	22.7%	-3.8%
Small General Service	2,376,188	(122,413)	322,640	(445,053)	1,931,135	15,716,314	14.0%	17.2%	-3.2%
General Service	17,940,936	(1,213,484)	3,219,941	(4,433,425)	13,507,511	135,436,741	11.1%	14.7%	-3.6%
Public Lighting	139,045	(4,929)	13,068	(17,997)	121,048	1,292,442	10.3%	11.9%	-1.6%
Municipal Pumping	643,225	(44,435)	117,907	(162,342)	480,883	4,666,160	11.5%	15.4%	-3.9%
Outdoor Lighting Service	110,173	(1,316)	3,488	(4,804)	105,369	457,911	29.9%	31.3%	-1.4%
Total North Dakota Electric	**$43,215,594**	**($2,394,010)**	**$6,332,297**	**($8,726,307)**	**$34,489,287**	**$272,977,449**	**14.5%**	**18.1%**	**-3.6%**

1/ Statement F, Schedule F-1, Pages 4-5 includes Transmission Cost Recovery Rider revenue.
2/ Generation Resource Recovery Rider revenue using Projected 2027 billing determinants and rates effective March 1, 2026 in Case No. PU-25-280.
3/ Renewable Resource Cost Adjustment revenue using Projected 2027 billing determinates and rates effective February 1, 2026 in Case No. PU-25-279.
4/ Reflects projected revenue from Transmission Cost Adjustment rates effective November 1, 2025 in Case No. PU-25-225, excluding transmission projects as shown on Statement L, page 3.
5/ Reflects the net increase for the TCA as $8,726,307 is already reflected in the current TCA rates.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Estimated Residential Bill Increases
2027

		Current Rates					Proposed Rates					Bill Change	
	Kwh	Basic Service Charge	Energy	Riders	FPP Charge	Total	Basic Service Charge	Energy	Riders	FPP Charge	Total	$ Increase	% Increase
January	1,200	$15.53	$62.35	$33.66	$26.83	$138.37	$30.63	$74.28	$28.03	$26.83	$159.77	$21.40	15.5%
February	1,100	14.03	59.03	30.86	24.60	128.52	27.66	69.97	25.70	24.60	147.93	19.41	15.1%
March	900	15.53	52.39	25.25	20.12	113.29	30.63	61.34	21.02	20.12	133.11	19.82	17.5%
April	800	15.03	49.07	22.44	17.89	104.43	29.64	57.02	18.69	17.89	123.24	18.81	18.0%
May	600	15.53	37.93	16.83	13.42	83.71	30.63	43.89	14.02	13.42	101.96	18.25	21.8%
June	600	15.03	37.93	16.83	13.42	83.21	29.64	43.89	14.02	13.42	100.97	17.76	21.3%
July	800	15.53	50.57	22.44	17.89	106.43	30.63	58.52	18.69	17.89	125.73	19.30	18.1%
August	800	15.53	50.57	22.44	17.89	106.43	30.63	58.52	18.69	17.89	125.73	19.30	18.1%
September	800	15.03	50.57	22.44	17.89	105.93	29.64	58.52	18.69	17.89	124.74	18.81	17.8%
October	700	15.53	44.25	19.64	15.65	95.07	30.63	51.21	16.35	15.65	113.84	18.77	19.7%
November	600	15.03	37.93	16.83	13.42	83.21	29.64	43.89	14.02	13.42	100.97	17.76	21.3%
December	900	15.53	52.39	25.25	20.12	113.29	30.63	61.34	21.02	20.12	133.11	19.82	17.5%
	9,800	$182.86	$584.98	$274.91	$219.14	$1,261.89	$360.63	682.39	$228.94	219.14	$1,491.10	$229.21	18.2%
Average	817	$15.24	$48.75	$22.91	$18.26	$105.16	$30.05	$56.87	$19.08	$18.26	$124.26	$19.10	18.2%

	Current	Proposed
Basic Service Charge/ Day	$0.501	$0.988
Energy		
1st 750 winter & summer	$0.06321	$0.07315
Over 750 winter	0.03321	0.04315
TCA	0.00340	(0.00129)
ECRR	0.00000	0.00000
GRRR	0.00327	0.00327
Renewable Rider	0.02138	0.02138
Fuel	0.02236	0.02236
Total Riders (excl Fuel)	0.02805	0.02336

MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-26-___

Direct Testimony
of
Stephanie Bosch

Q. Please state your name and business address.

A. My name is Stephanie Bosch and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Please describe your duties as Regulatory Affairs Manager.

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the administration of the Company's gas and electric tariffs and the preparation of miscellaneous rate filings.

Q. Please describe your education and professional background.

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and Financial Economics. I joined Montana-Dakota in June 1997 as a Rate Clerk in the Regulatory Affairs Department and held positions of increasing responsibility within the department until 2011 when I left the Company. In

2013, I returned to the Company as a Regulatory Analyst before attaining my current position in August 2015.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of Montana and Wyoming and the Public Utilities Commissions of Minnesota and South Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the projected billing determinants allocated to the Company's various rate schedules and priced at current rates, as included in Statement F, Schedule F-1 of this Application. I also present the proposed rate schedules provided in Appendix B to the Application and other proposed changes to the Company's tariff.

Additionally, I present the apportionment of the interim increase among the various rate classes and the proposed interim rate schedules provided in Appendix A to this Application for Interim Increase in Electric Rates.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement F, Schedule F-1 and the proposed rate schedules provided in Appendix B to the Application.

I am also sponsoring Exhibit No. __(SB-1), a proposed new rate schedule entitled Summary Billing Plan Rate 115 and Exhibit No. __(SB-2), the interim bill impact for a residential customer.

Lastly, I am sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

<u>Projected Billing Determinants and Revenue Analysis</u>

Q. Please describe the derivation of the Company's projected billing determinants used in this rate case.

A. First, I will discuss how Montana-Dakota derived the projected 2026 and 2027 customer counts included in this rate case. To start, Montana-Dakota determined the average number of customers for 2025 by rate schedule, with the exception of Irrigation Power Service Rate 25. As service under Rate 25 is seasonal, Montana-Dakota set the customer count at the total number of customers taking service under the rate in 2025.

Montana-Dakota then applied an average growth rate to the 2025 customer counts for Residential Electric Service Rate 10, Small General Electric Service Rate 20, General Electric Service Rate 30 – Secondary and General Electric Space Heating Service Rate 32 – Secondary. For all other rate schedules, the Company projects no growth in customers and therefore set the projected 2026 and 2027 customer counts at the same level as 2025.

For the projected 2026 and 2027 energy use, Montana-Dakota started with the overall projected North Dakota energy use included in the Company's financial and electric load forecasts as outlined in the direct testimony of Mr. Brian Giggee. Because the customer classes included in the Company's electric load forecast do not align directly with the Company's rate schedules, Montana-Dakota allocated the forecasted North Dakota energy use to each of the respective rate schedules for those rate schedules with projected customer growth based on their 2025 energy use. If no customer growth is projected, the Company set the energy use the same as that in 2025.

The Company next projected customer demand by rate schedule, if applicable, by maintaining each rate schedule's 2025 monthly load factor when applying that rate schedule's projected energy use.

Q. Please explain the calculation of the projected revenue at current rates included in Statements F, Schedule F-1.

A. The Company applied the Basic Service Charges, Energy Charges, and Demand Charges, authorized in Case No. PU-22-194, to the projected number of customers, energy use, and demand to derive the revenues summarized on Statement F, Schedule F-1, page 1. In addition, the Company priced the projected energy use at the currently authorized Transmission Cost Adjustment rates, restated to include only transmission project costs. As Mr. Bradley J. Davison explains in his direct testimony, Montana-Dakota is moving the transmission projects currently recovered through the Transmission Cost Adjustment rates into base rates in this case. Therefore, to correctly reflect the recovery of all costs to be recovered through base rates, Montana-Dakota included the current Transmission Cost Adjustment rates, limited to transmission project costs, in its revenues.

The Fuel and Purchased Power rates used in revenues reflect the projected Fuel and Purchased Power rates developed by Mr. Davison. The Company is not proposing any changes to the costs recovered through either the Generation Resource Recovery Rider or the Renewable Resource Cost Adjustment and therefore excluded those riders from the projected revenue at current rates.

<u>Proposed Tariff Changes</u>

Q. The Company is proposing a new rate schedule, Summary Billing Plan Rate 115, attached to your testimony as Exhibit No. __(SB-1). What is Summary Billing and why is Rate 115 being proposed?

A. Summary Billing Plan Rate 115 is an optional billing arrangement that allows qualifying customers with multiple premises to consolidate the billing of those premises under one account. The new rate schedule outlines the general availability of this new billing arrangement and the terms and conditions for enrolling in and maintaining eligibility under the plan.

The proposed rate schedule is in response to customer requests to consolidate the monthly Montana-Dakota bills from a customer's multiple locations into one account, resulting in one monthly bill and one payment. The Company recognizes the value of a bill consolidation program for participating customers. However, the Company believes the optional billing arrangement is best managed through a defined program that explains participating customers' responsibilities and the Company's requirements for continued participation in the plan.

Q. The Company is proposing an Off-Peak Demand Charge be applicable to customers taking service under Optional Time-of-Day General Electric Service Rate 31. Why?

A. Before Montana-Dakota's 2003 rate case, Case No. PU-399-03-296, Rate 31 included an off-peak demand charge that was applied when the customer's off-peak Kw exceeded the on-peak Kw. In that case, the Company proposed eliminating the off-peak demand charge rate to encourage customers to shift load to the off-peak period.

Customers continue to benefit from moving their load to the off-peak hours. However, the current rate structure does not recover any demand-related costs through the demand charge when a customer's operations occur primarily during off-peak hours. The proposed structure reintroduces an off-peak demand charge that will recover some costs from primarily off-peak customers, but at a much lower rate than the on-peak rate. This preserves the incentive for customers to move load to the Company's off-peak hours while also providing the Company with a greater recovery of demand-related system costs.

Additionally, the proposed off-peak demand charge will apply only when a customer's off-peak demand exceeds the customer's on-peak demand. The Company will bill the off-peak Kw that exceeds the on-peak Kw at the proposed off-peak demand charge of $2.50 per Kw.

Q. How will customers be impacted by the proposed re-introduction of an off-peak demand charge?

A. As with many bill impacts, the effect depends on the customer's demand. A customer with relatively similar on-peak and off-peak demand will see minimal impact. Conversely, a customer that operates primarily during off-peak hours will see a larger increase because the off-peak demand exceeding that of the on-peak period will now be subject to a rate of $2.50 per Kw. Today, that customer pays nothing for off-peak demand.

Q. Please briefly describe any additional changes the Company is proposing to the Company's electric tariff.

A. The Company proposes the following changes to its electric tariff as identified in the legislative copy of the tariff provided in Appendix B of the Application:

- The rates described by Mr. Ron Amen have been incorporated into the proposed rate schedules.
- The removal of a contract requirement under the Availability provision of Municipal Pumping Service Rate 48 and the discount provision provided for under the Rates section of the tariff. Contracts are no longer a requirement for service under the rate.

- A clarifying change to the Availability provision of Outdoor Lighting Service Rate 52 to state that billboard lighting under the rate schedule is available only for traditional or non-electronic billboards. The rate’s charges and provisions assume that the customers’ hours of operation occur primarily during the evening and night. An electronic billboard operates all day and therefore does not reflect the type of operations intended to be served under Rate 52.
- A new sub-provision (Section III.1.vi) to General Provisions Rate 100 to inform customers that the Company is not required to change the rate schedule under which a customer receives service more than once a year unless there is a material change in the customer’s load that alters the availability or applicability of that rate.
- Two new sub-provisions to Electric Service Rules and Regulations Rate 110: (1) New sub-section 109.4 to Section 109 Consultation with the Company. This provision advises interested parties that equipment used to provide electric service to a customer has a definite capacity. Customers should not make material increases in load or equipment without first discussing those changes with the Company to ensure Montana-Dakota can continue to provide safe and adequate service with no material adverse effects for the Company or the customer. (2) New sub-section 402.1 to Section 402 Service Connections and Disconnections. This provision advises interested parties that the Company will connect electric service to a

previously served location without an affidavit or wiring certificate if all conditions are met. This ensures that no material changes have occurred to the service and that the Company can provide safe and reliable service at a previously served location after a lapse in service.

- The removal of sub-provision 3 to Metering Transformer Enclosure (Secondary Service) under Section 600 – Metering of Electric Service Rules and Regulations Rate 110. The Company is removing the minimum size requirement for a metering transformer enclosure. Instead, customers should consult with the Company before purchasing and installing any metering transformer enclosure to ensure they meet any minimum size or other service-specific requirements.
- There are other minor wording changes listed throughout the Company's rate book to improve the readability of the rate without modifying any conditions, update the rate and/or page references or are self-explanatory. These changes are clearly denoted on the tariff sheets in the legislative format.

<u>Interim Increase</u>

Q. How did the Company apportion the proposed interim revenue requirement among the customer classes?

A. The Company proposes billing the interim revenue increase of $26,347,265 as a separate line item on the bill, based on 19.620 percent of the amounts billed under the Basic Service Charge, Energy Charge, and Demand Charges applicable under the Company’s rate schedules.

Statement K, attached to this Application for interim Increase in Electric Rates, provides calculations supporting the application of the interim increase to each rate class. The proposed tariff sheets reflect the proposed interim rate of 19.620 percent to be applied to the amount billed under the Basic Service Charge, Energy Charge, and Demand Charges. The interim rate will not apply to the amount billed under the Fuel and Purchased Power or any of the Company’s riders (Renewable Resource Cost Adjustment, Generation Resource Recovery Rider, Environmental Cost Recovery Rider and Transmission Cost Adjustment).

Q. As discussed by Mr. Davison, the Company is proposing to move all transmission project costs currently being recovered through Montana-Dakota's Transmission Cost Adjustment rates into base rates. What effect does this movement have on the Company’s interim rates?

A. As discussed earlier in my testimony, the Company’s projected 2027 revenues include a Transmission Cost Adjustment rate reflective of the transfer of transmission project costs currently recovered under Rate 59 into the Company’s base rates. The same holds true for the Company’s interim revenues.

Therefore, to avoid the double recovery of these costs through both the interim rate and Montana-Dakota's Transmission Cost Adjustment rates, the Transmission Cost Adjustment rates must be adjusted to reflect the removal of these same project costs coincident with interim rates.

The net bill impact to Montana-Dakota customers is twofold, an increase in customers bill due to the implementation of the proposed interim rate and a decrease in the Transmission Cost Adjustment rates effective the same day. Customers in North Dakota will see an overall bill impact of 7.4 percent, comprised of an interim bill increase of 11.0 percent and a Transmission Cost Adjustment bill decrease of 3.7 percent.

A typical residential customer will see a net bill increase of approximately $9.00 per month or 8.3 percent over current rates as shown on Exhibit No. __(SB-2). The net increase is comprised of two components, an increase due to the interim rate and a decrease due to the change in the Transmission Cost Adjustment of moving the projects into base rates.

Q. Does this conclude your testimony?

A. Yes.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

NDPSC Volume 5
Original Sheet No. 63

SUMMARY BILLING PLAN Rate 115

AVAILABILITY:

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

GENERAL TERMS AND CONDITIONS:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

NDPSC Volume 5
Original Sheet No. 63.1

SUMMARY BILLING PLAN Rate 115

   a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements.
   a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Residential Electric Service Rate 10
Bill Impact - Interim

		Current Rates						
	Kwh	Basic Service Charge	Energy	Generation Rider	Renewable Rider	Transmission Rider	F&PP Charge	Total Current Bill
January	1,200	$15.53	$62.35	$3.92	$25.66	$4.08	$26.83	$138.37
February	1,100	14.03	59.03	3.60	23.52	3.74	24.60	128.52
March	900	15.53	52.39	2.94	19.24	3.06	20.12	113.28
April	800	15.03	49.07	2.62	17.10	2.72	17.89	104.43
May	600	15.53	37.93	1.96	12.83	2.04	13.42	83.71
June	600	15.03	37.93	1.96	12.83	2.04	13.42	83.21
July	800	15.53	50.57	2.62	17.10	2.72	17.89	106.43
August	800	15.53	50.57	2.62	17.10	2.72	17.89	106.43
September	800	15.03	50.57	2.62	17.10	2.72	17.89	105.93
October	700	15.53	44.25	2.29	14.97	2.38	15.65	95.07
November	600	15.03	37.93	1.96	12.83	2.04	13.42	83.21
December	900	15.53	52.39	2.94	19.24	3.06	20.12	113.28
	9,800	$182.86	$584.98	$32.05	$209.52	$33.32	$219.14	$1,261.87

		Proposed Interim Rates								Bill Change	
	Kwh	Basic Service Charge	Energy	Generation Rider	Renewable Rider	Transmission Rider	F&PP Charge	Interim Increase 1/	Total Current Bill	$ Increase	% Increase
January	1,200	$15.53	$62.35	$3.92	$25.66	($1.55)	$26.83	$15.28	$148.02	$9.65	7.0%
February	1,100	14.03	59.03	3.60	23.52	(1.42)	24.60	14.33	137.69	9.17	7.1%
March	900	15.53	52.39	2.94	19.24	(1.16)	20.12	13.33	122.39	9.11	8.0%
April	800	15.03	49.07	2.62	17.10	(1.03)	17.89	12.58	113.26	8.83	8.5%
May	600	15.53	37.93	1.96	12.83	(0.77)	13.42	10.49	91.39	7.68	9.2%
June	600	15.03	37.93	1.96	12.83	(0.77)	13.42	10.39	90.79	7.58	9.1%
July	800	15.53	50.57	2.62	17.10	(1.03)	17.89	12.97	115.65	9.22	8.7%
August	800	15.53	50.57	2.62	17.10	(1.03)	17.89	12.97	115.65	9.22	8.7%
September	800	15.03	50.57	2.62	17.10	(1.03)	17.89	12.87	115.05	9.12	8.6%
October	700	15.53	44.25	2.29	14.97	(0.90)	15.65	11.73	103.52	8.45	8.9%
November	600	15.03	37.93	1.96	12.83	(0.77)	13.42	10.39	90.79	7.58	9.1%
December	900	15.53	52.39	2.94	19.24	(1.16)	20.12	13.33	122.39	9.11	8.0%
	9,800	$182.86	$584.98	$32.05	$209.52	($12.62)	$219.14	$150.66	$1,366.59	$104.72	8.3%
Average	817									$8.73	

	Current		Proposed Interim	
Basic Service Charge/ Day	$0.501		$0.501	
Energy				
1st 750 winter & summer	$0.06321		$0.06321	
Over 750 winter	$0.03321		$0.03321	
Transmission Rider	$0.00340	2/	($0.00129)	5/
Generation Rider 3/	$0.00327		$0.00327	
Renewable Rider 4/	$0.02138		$0.02138	
Fuel & Purchased Power	$0.02236		$0.02236	6/

1/ Interim Increase 19.620% Applicable to amounts billed under the Basic Service Charge, Energy Charges and Demand Charges.
2/ Rate effective November 1, 2025.
3/ Rate effective March 1, 2026.
4/ Rate effective February 1, 2026.
5/ Rate effective November 1, 2025 excluding transmission projects moved to base rates.
6/ Projected 2027 F&PP rate.