NORTH DAKOTA RATE CASE 2023

Otter Tail Power Company

Before the
North Dakota Public Service Commission

Application for Authority to
Increase Electric Rates in North Dakota
Case No. PU-23

November 2, 2023

Volume 2B
Direct Testimony and Supporting Schedules

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

OTTER TAIL POWER COMPANY

Otter Tail Power Company
North Dakota General Rate Case Documents
Case No. PU-23-

Volume 2B
Direct Testimony and Supporting Schedules

Todd R. Wahlund
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Volume 2B

Direct Testimony and Supporting Schedules:

Todd R. Wahlund

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

FINANCIAL SOUNDNESS, CAPITAL STRUCTURE AND COST OF CAPITAL

Direct Testimony and Schedules of

TODD R. WAHLUND

November 2, 2023

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND EMPLOYER.

A. My name is Todd R. Wahlund. I currently am employed by Otter Tail Power Company ("OTP" or the "Company"). Effective January 1, 2024, I will be employed by Otter Tail Corporation. OTP is a wholly owned subsidiary of Otter Tail Corporation.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES.

A. I am OTP's Chief Financial Officer. Effective January 1, 2024, I will become the Chief Financial Officer and Vice President of Otter Tail Corporation and will be responsible for the financial functions and performance for Otter Tail Corporation and its operating company subsidiaries, including OTP. I also will direct the corporate services for treasury, accounting, tax and external reporting, investor relations, financial planning, information technology, internal audit and business risk management, and acquisition evaluations.

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS?

A. Yes, a description of my qualifications is included as Exhibit___(TRW-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support OTP's capital structure and overall rate of return (ROR). In connection therewith, I discuss several issues that are related to OTP's proposed capital structure and ROR, including OTP's prior and planned capital expenditures, credit ratings and unique financial characteristics. Finally, I sponsor the information provided in Volume 3, Rate of Return/Cost of Capital Schedules Tab, Schedules D-1 through D-4.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. My Direct Testimony:

- Demonstrates the reasonableness of OTP's 2024 Test Year capital structure and costs of long-term debt (LTD), short-term debt (STD) and the overall

ROR;

- Discusses the financial impacts and scope of OTP's recent capital expenditures and OTP's estimated future capital expenditures;
- Discusses how constructive regulatory policy, including a reasonable return on equity (ROE), is important for OTP to maintain its strong senior unsecured credit ratings, support OTP's capital expenditures, and enable OTP to attract capital and provide service at a fair and reasonable cost;
- Explains the unique financial characteristics of OTP and how they affect the cost of equity for OTP; and
- Presents OTP's 2024 Test Year capital structure and overall ROR.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR DIRECT TESTIMONY.

A. OTP's 2024 Test Year capital structure, costs of LTD, STD and ROR are reasonable and should be adopted for determining OTP's rates. Table 1, below, summarizes OTP percentages and costs of LTD, STD, and common equity percentages and costs. These amounts also are shown in Exhibit___(TRW-1), Schedule 2.

Table 1
Recommended 2024 Test Year Capital Structure and ROR

Component	Percentage	Cost	Weighted Cost
Short-Term Debt	2.98%	5.25%	0.16%
Long-Term Debt	43.52%	4.65%	2.02%
Total Debt	46.50%	4.68%	2.18%*
Common Equity	53.50%	10.60%	5.67%
Total	100.00%		7.85%

*Weighted cost of total debt reflects costs of short-term debt and long-term debt before rounding to two decimals.

OTP has been engaged in an extensive investment program, involving capital expenditures of approximately $1.133 billion from 2018 through 2023, or an average of approximately $189 million per year.[1] These extensive capital expenditures are projected to continue, with OTP's capital expenditures projected to be approximately $888 million in 2024-2027 (an average of $222 million per year).[2] The Commission's decisions in this proceeding, including the

[1] See Table 2, below.
[2] Otter Tail Corporation Second Quarter Earnings Conference Call Presentation at 36 (Aug. 1, 2023).

Commission's decisions regarding OTP's capital structure and ROE could significantly affect the costs of financing these expenditures.

Q. WHAT DO YOU RECOMMEND TO THE COMMISSION?

A. I recommend the Commission approve a capital structure for the 2024 Test Year consisting of 53.50 percent equity, 43.52 percent LTD, and 2.98 percent STD. I also recommend the Commission approve an overall ROR of 7.85 percent and a ROE of 10.60 percent.

Q. HOW IS THE BALANCE OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The balance of my Direct Testimony is organized as follows:

- Section III describes our historic and planned financing and investment activities and explains the importance of our regulatory environment and investor perceptions to our capital expenditure plans and costs.
- Section IV discusses OTP's credit ratings.
- Section V discusses some of OTP's unique financial characteristics.
- Section VI describes OTP's proposed capital structure, including its components.
- Section VII summarizes my conclusions.

III. OTP CAPITAL EXPENDITURES AND ONGOING EXPENDITURE PLANS

Q. PLEASE SUMMARIZE OTP'S CAPITAL EXPENDITURES SINCE ITS LAST NORTH DAKOTA RATE CASE.

A. OTP's last North Dakota rate case (Case No. PU-17-398) was filed in November 2017 based on a 2018 Test Year. OTP's capital expenditures from 2018-2023 will total approximately $1.133 billion, as shown on Table 2 below.

Table 2
OTP Capital Expenditures 2018 – 2023[3]

Year	OTP Total Capital Expenditure ($ millions)
2018	$87
2019	$187
2020	$357
2021	$140
2022	$148
2023 (Est)	$214
Total	$1,133
Average	$189

Q. HOW DO THESE PRIOR EXPENDITURES COMPARE TO OTP'S NET PLANT IN SERVICE?

A. OTP's net electric plant in service was approximately $1.451 billion as of December 31, 2017.[4] OTP's $1.133 billion capital expenditures during 2018-2023 represents approximately 78 percent of its net electric plant at the beginning of that period. The result, after plant retirements, was a net increase in OTP's net electric plant in service of approximately $647 million, to approximately $2.098 billion as of December 31, 2022.[5] Mr. Gerhardson also provides further information regarding these expenditures.

Q. PLEASE SUMMARIZE OTP'S ANTICIPATED CAPITAL EXPENDITURES.

A. We anticipate an additional $888 million of capital expenditures by OTP from 2024 through 2027.[6] Mr. Gerhardson further explains OTP's capital expenditure plans in his Direct Testimony.

Q. HOW HAS OTP FINANCED ITS RECENT CAPITAL EXPENDITURES?

A. OTP has obtained long term funding for its $1.133 billion of capital expenditures during 2018-2023 through a combination of approximately $355 million of LTD issued by OTP (net of retirements), $115.2 million of earnings retained by OTP and $300.0 million of equity infusions from Otter Tail Corporation. The sum of

[3] Otter Tail Corporation 2018 Form 10-K at 51; Otter Tail Corporation 2020 Form 10-K at 30; Otter Tail Corporation 2022 Form 10-K at 34; Otter Tail Corporation Second Quarter Earnings Conference Call Presentation at 36 (Aug. 1, 2023).
[4] Otter Tail Corporation 2018 Form 10-K at 112.
[5] Otter Tail Corporation 2022 Form 10-K at 54.
[6] Otter Tail Corporation Second Quarter Earnings Conference Call Presentation at 36 (Aug. 1, 2023).

those retained earnings plus equity infusions reflects the net level of reinvestment of OTP earnings.

Q. HAVE YOU SUMMARIZED THOSE RETAINED EARNINGS AND EQUITY INFUSIONS?

A. Yes. Table 3 below identifies the net reinvestment in OTP (the sum of OTP retained earnings plus Otter Tail Corporation equity infusions) for the years 2018-2023. During that time, almost all of OTP's net income has been reinvested in utility operations, either as retained earnings or added infusions of equity from Otter Tail Corporation.

Table 3
Net Reinvestment of OTP Earnings
($ millions)

	OTP Net Income	Retained Earnings	Otter Tail Corp Equity Infusions	Net Reinvestment [Retained Earnings + Otter Tail Corp Equity Infusions]	Effective Rate of Reinvestment
2018	$54.4	$11.9	$25.0	$36.9	67.8%
2019	$59.0	$14.5	$35.0	$49.5	83.9%
2020	$66.8	$22.3	$150.0	$172.3	257.9%
2021	$72.5	$20.6	$0.0	$20.6	28.4%
2022	$80.0	$25.0	$50.0	$75.0	93.8%
2023 (Est)	$84.8	$20.8	$40.0	$60.8	71.7%
Total	$417.5	$115.2	$300.00	$415.2	99.4%
Average	$69.6	$19.2	$60.0	$79.2	113.8%

These retained earnings and equity infusions have provided essential funding and have allowed OTP to maintain an appropriate balance of debt and equity and a balanced capital structure for OTP.

Q. HAS THE IMPORTANCE OF OTP'S BALANCED CAPITAL STRUCTURE AND OTTER TAIL CORPORATION EQUITY INFUSIONS BEEN RECOGNIZED BY RATING AGENCIES?

A. Yes. Fitch Ratings (Fitch) has stated:

> Fitch expects OTP to remain FCF [Free Cash Flow] negative through the forecast period, with future funding needs met by a balanced mix of debt and equity, and that parent Otter Tail Corp. will downstream

> additional equity as needed to support the balanced capital structure.[7]

Fitch's credit rating for OTP also assumes that OTP's "large capex program" will be supported by a "balanced capital structure."[8] Similarly, Moody's Investors Service (Moody's) supported its credit rating for OTP by stating "We expect OTP's capital structure to remain consistent as the company executes its investment program."[9]

Q. DID FITCH IDENTIFY ANY RISKS ASSOCIATED WITH FAILURE TO MAINTAIN A BALANCED CAPITAL STRUCTURE?

A. Yes. Fitch identified the following factors that could, individually or collectively, lead to negative rating action or downgrade:

- Adverse future regulatory outcomes.
- Failure to maintain a balanced equity component in its capital structure.
- Sustained FFO leverage above 4.5x.[10]

Q. WILL THE ROE AND CAPITAL STRUCTURE APPROVED BY THE COMMISSION IMPACT OTP'S CAPITAL EXPENDITURES AND COST?

A. Yes. The ROE and capital structure authorized in this proceeding will have a substantial impact on OTP's ability to carry out its capital expenditures and the ongoing cost of doing so in two important ways.

First, the ROE and capital structure will have a direct impact on OTP's level of authorized earnings, which will, in turn, directly affect OTP's ability to fund capital expenditures with internally generated retained earnings. As shown above, internally generated retained earnings have been a significant source of funding for OTP's capital expenditures, and OTP expects retained earnings to continue to be a significant source of funding for its future capital expenditure plans.

Second, the authorized ROE and capital structure will have a significant effect on rating agencies and investors' perceptions of OTP, the effect of which is

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[7] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 4 (Sept. 22, 2023).
[8] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 5 (Sept. 22, 2023).
[9] Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 1 (Oct. 3, 2022).
[10] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 5-6 (Sept. 22, 2023). "FFO" stands for Funds from Operations.

likely to be heightened by the scale of OTP's planned capital expenditures. These perceptions will have a substantial impact on both the availability and the cost of the capital needed to complete OTP's capital expenditure plans.

IV. OTP CREDIT RATINGS

Q. ARE CREDIT RATINGS IMPORTANT TO OTP AND OTP'S CUSTOMERS?

A. Yes. Although, OTP has not issued publicly held debt (instead issuing debt through private placements), credit ratings still are very important to OTP and OTP's customers. That is because institutional investors use credit ratings, along with their own analysis, to decide whether to purchase OTP debt and at what price, which in turn, drives the interest rate on that debt. Credit ratings therefore impact the cost of LTD (and STD) OTP requires to fund its substantial capital expenditures.

Q. WHAT ARE OTP'S CURRENT CREDIT RATINGS?

A. OTP's current senior unsecured credit ratings are set out in Table 4 below:

Table 4
OTP Credit Ratings[11]

	Moody's	**Fitch**	**S&P**
Long Term Issuer Default	A3	BBB+	BBB+
Senior Unsecured Debt	N/A	A-	N/A
Outlook	Stable	Stable	Stable

Q. WHAT FACTORS DO AGENCIES CONSIDER WHEN ESTABLISHING A UTILITY'S RATINGS?

A. Credit rating agencies look at a utility's business risk and its financial risk (based on credit metrics) in making rating determinations. Ratings are assigned to both business and financial risks. A utility's required credit metrics increase (become more stringent) to maintain a given rating as the utility's business risk rating decreases (indicating higher business risk). Capital expenditure levels and the regulatory environment are both significant to rating agencies' evaluation of a utility's credit ratings.

[11] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 7-8 (Sept. 22, 2023).; Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 1 (Oct. 3, 2022); S&P Global Ratings, Otter Tail Power Co. RatingsDirect at 6-7 (Sept. 22, 2023).

Q. HAS OTP'S CAPITAL EXPENDITURE LEVEL BEEN RECOGNIZED AS A CREDIT RATING FACTOR?

A. Yes. Fitch, Moody's and Standard & Poor's Financial Services (S&P) all identify OTP's planned capital expenditures as factors influencing their credit ratings, with Fitch and Moody's noting those capital expenditures need to be supported by a balanced capital structure and supportive regulatory environments.[12]

Q. HOW DO RATING AGENCIES VIEW THE NORTH DAKOTA REGULATORY ENVIRONMENT?

A. Both Fitch and Moody's consider North Dakota to be credit supportive.[13]

Q. ARE OTP'S CREDIT RATINGS PREDICATED ON A CONTINUED CONSTRUCTIVE REGULATORY ENVIRONMENT?

A. Yes. Fitch, for example, viewed the outcome of OTP's last North Dakota rate case to be "constructive", and that it expects OTP's "regulatory environment to remain supportive of credit quality…."[14] Moody's similarly characterizes OTP's regulatory environment to be "credit supportive" and that its stable outlook for OTP "incorporates our expectation that the company's regulatory environments will remain credit supportive…."[15]

Q. HAVE THE RATING AGENCIES STATED THAT A CHANGE IN OTP'S REGULATORY ENVIRONMENT COULD RESULTS IN A DOWNGRADE?

A. Yes. Fitch expressly identified "adverse future regulatory outcomes" as a factor that could lead to a negative rating action or downgrade.[16]

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[12] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 5-6 (Sept. 22, 2023); Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 1-2 (Oct. 3, 2022; S&P Global Ratings, Otter Tail Power Co. RatingsDirect at 1 (Sept. 22, 2023).
[13] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 2-3 (Sept. 22, 2023); Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 1 (Oct. 3, 2022).
[14] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 1-2 (Sept. 22, 2023).
[15] Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 1-2 (Oct. 3, 2022).
[16] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 5 (Sept. 22, 2023).

Q. WHAT KIND OF DECISIONS COULD CONSTITUTE AN ADVERSE REGULATORY OUTCOME?

A. From a rating agency perspective, regulatory decisions that put additional pressure on credit metrics could be considered adverse. For example, Moody's has stated:

> A rating downgrade is possible if OTP's regulatory environments become less credit supportive, such that regulatory lag increase or returns are lowered.[17]

Further, Fitch has noted jurisdictions where authorized ROEs are "materially below the recent industry average" are "somewhat challenging" and such decisions are "unfavorable."[18] These kinds of decisions put pressure on earnings, which, in turn, puts pressure on credit metrics.

Q. ARE THERE OTHER REGULATORY DECISIONS THAT COULD BE CONSIDERED ADVERSE FROM A CREDIT PERSPECTIVE?

A. Yes. As discussed above, ratings agencies predicate OTP's credit on the assumption that OTP will finance its future capital expenditures through a balanced capital structure. Moving away from financing future capital expenditures through a balance of debt and equity would put additional pressure on credit metrics (i.e. make credit ratings agencies look less favorably on the company), both by reducing the amount of internally generated earnings available to fund capital expenditures, and by increasing OTP's debt burden. Further, if the Commission issues a decision that fails to reflect OTP's actual, Test Year capital structure, credit rating agencies could interpret that decision as a deviation from past precedent that signals the Commission becoming less supportive of North Dakota utilities.

Q. ARE THERE OTHER BUSINESS RISKS THAT IMPACT OTP'S CREDIT RATINGS?

A. Yes. Fitch notes OTP's credit profile is similar to the credit profile of its larger peers, despite having better financial metrics and operating in the same jurisdictions:

> OTP's credit profile is in line with those of its higher rated peers including Black Hills Power, Inc. (BHP; BBB+/Stable), Northern

[17] Moody's Investors Service, Otter Tail Corporation and Otter Tail Power Company Rating Action at 2 (Oct. 3, 2022).
[18] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 3, 4 (Sept. 22, 2023).

> States Power Company- Minnesota (NSPC; A-/Stable) and NorthWestern Corp. (NorthWestern; BBB/Stable). OTP's financial metrics are stronger than peers and in line with a 'BBB+' IDR.
>
> OTP's FFO leverage strengthened to 3.8x in 2022 from 4.2x in 2021, which was slightly stronger than NSPC at 3.9x, better than BHP at 4.2x and significantly better than NorthWestern at 6.0x. Fitch considers OTP's regulatory environment in Minnesota and North Dakota to be balanced, while the regulatory environment in South Dakota is somewhat challenging. OTP's peers operate in many of the same states. However, the scale of OTP's utility operations are much smaller than some of its larger peers.[19]

S&P similarly notes OTP's "small customer base of about 133,000 customers" is a key risk in OTP's credit rating.[20]

Q. WHAT DO YOU CONCLUDE FROM THESE RATING AGENCY REPORTS?

A. These reports confirm OTP's regulatory environment is closely followed by the rating agencies and investors, and that Commission decisions in this case will have a significant effect on OTP's completion of its capital expenditure program and on OTP's cost of completing that program.

V. UNIQUE FINANCIAL CHARACTERISTICS OF OTP

Q. PLEASE SUMMARIZE THE FINANCIAL CHARACTERISTICS OF OTP.

A. OTP is a small utility and provides electricity to approximately 133,000 customers in a service area encompassing 70,000 square miles and over 400 communities.[21] OTP's breakdown of electric revenues was 67.7 percent Commercial and Industrial, 30.6 percent Residential and 1.7 percent other sources.[22] OTP has an extensive capital expenditure program in effect as previously discussed. OTP is the only utility operating subsidiary of Otter Tail Corporation.[23]

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[19] Fitch Ratings, Fitch Upgrades Otter Tail Corp. and Otter Tail Power's IDRs; Outlooks Stable at 4-5 (Sept. 22, 2023).
[20] S&P Global Ratings, Otter Tail Power Co. Ratings Direct at 1 (Sept. 22, 2023).
[21] Otter Tail Corporation 2022 Form 10-K at 5.
[22] Otter Tail Corporation 2022 Form 10-K at 6. One Industrial customer accounts for over 10 percent of OTP's revenues. *Id.*
[23] Otter Tail Corporation 2022 Form 10-K at 3.

Q. HOW DOES OTP COMPARE IN SIZE TO OTHER UTILITIES?

A. OTP's overall size, including all states in which it does business, is very small compared to other utilities. OTP is Otter Tail Corporation's only utility. Otter Tail Corporation is the fourth smallest (by market capitalization) publicly owned utility in the United States.[24] OTP Witness Ms. Ann Bulkley explains the substantial difference in size between OTP (and Otter Tail Corporation) and the companies in her comparable group and the significance of that difference to OTP's cost of equity.

Q. DOES OTTER TAIL CORPORATION HAVE A LOW AVERAGE DAILY TRADING VOLUME AND RELATIVELY LOW LEVELS OF INSTITUTIONAL OWNERSHIP?

A. Yes. Ms. Bulkley explains Otter Tail Corporation's average daily trading volume and level of institutional ownership are considerably lower than the other electric utilities in her comparable group.

Q. WHAT ARE THE EFFECTS OF RELATIVELY LOW TRADING VOLUME AND INSTITUTIONAL OWNERSHIP?

A. A low average daily trading volume limits liquidity for institutional investors, who take significant positions in any stock they purchase. With low average daily trading volume, institutional investors may be limited in their ability to exit an ownership position, which is an impediment to their purchase of a stock. This lower average daily trading volume impacts the liquidity of trading in a stock. Liquidity matters because it influences the cost of capital for the suppliers of shares and the cost of trading for investors. The lower the liquidity, the higher the required returns for investors and the higher cost of capital for companies that issues the shares. Ms. Bulkley's Direct Testimony also explains the effect of relatively low institutional ownership on OTP's cost of equity.

Q. PLEASE FURTHER EXPLAIN INSTITUTIONAL OWNERSHIP AND ITS EFFECT AS A SOURCE OF EQUITY CAPITAL.

A. Institutional ownership measures the level of ownership of a company by large financial institutions, mutual funds, insurance companies, and endowments. A significant benefit of institutional investors is they provide an added source of demand for capital and tend to be an efficient source of equity capital.

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[24] Edison Electric Institute, 2023 Q2 Financial Update (last accessed Sept. 17, 2023).

Q. HOW DOES THIS COMBINATION OF FACTORS AFFECT THE COST OF EQUITY FOR OTP?

A. This combination of factors increases the cost of equity for OTP.

VI. OTP TEST YEAR CAPITAL STRUCTURE AND RATE OF RETURN

Q. PLEASE SUMMARIZE OTP'S RECOMMENDED CAPITAL STRUCTURE, COSTS OF DEBT, AND ROR FOR THE 2024 TEST YEAR.

A. OTP recommends an overall ROR of 7.85 percent, which is based on the percentages and costs of LTD, STD, and common equity summarized in Table 5 below (which is a duplicate of Table 1 and provided here for convenience) and shown on attached Exhibit___(TRW-1), Schedule 2.

Table 5
Recommended 2024 Test Year Capital Structure and ROR

Component	Percentage	Cost	Weighted Cost
Short-Term Debt	2.98%	5.25%	0.16%
Long-Term Debt	43.52%	4.65%	2.02%
Total Debt	46.50%	4.68%	2.18%*
Common Equity	53.50%	10.60%	5.67%
Total	100.00%		7.85%

*Weighted cost of total debt reflects costs of short-term debt and long-term debt before rounding to two decimals.

The cost of common equity and proposed ROE are explained in the Direct Testimony of Ms. Bulkley.

Q. HOW DO THE PROPOSED ROR, CAPITAL STRUCTURE AND CAPITAL COSTS COMPARE TO THOSE IN OTP'S LAST NORTH DAKOTA RATE CASE?

A. The proposed 7.85 percent ROR is 21 basis points higher than the 7.64 percent ROR approved by the Commission in OTP's last North Dakota general rate case.[25] The proposed ROR reflects a decrease in the cost of LTD (from 5.35 percent to 4.65 percent), an increase in the cost of STD (from 3.84 percent to 5.25 percent) and an increase in ROE (from 9.77 percent to 10.60 percent). The proposed 53.50 percent

[25] *Otter Tail Power Company 2017 Electric Rate Increase Application*, NDPSC Case No. PU-17-398, Order on Settlement (Sept. 26, 2018).

equity ratio is an increase from the 52.50 percent equity ratio approved in that case.

Q. DOES OTP'S CAPITAL STRUCTURE BENEFIT CUSTOMERS?

A. Yes. OTP's capital structure, including its equity ratio, has a significant effect on its financial strength. The equity ratio is an important credit metric for rating agencies in determining OTP's credit ratings. OTP's capital structure also assists OTP in financing its investments and operations at a reasonable cost and ensures OTP's ability to access capital markets in a variety of economic conditions. OTP's capital structure has contributed to OTP's ability to simultaneously finance its significant capital expenditures, maintain its ratings from Moody's and obtain an upgrade of its ratings from S&P and Fitch, and reduce its cost of LTD. Finally, we expect OTP's capital structure and equity ratio also will facilitate OTP's completion of its future capital expenditure plan. All these factors benefit OTP customers.

A. Capital Structure

Q. IS OTP'S CAPITAL STRUCTURE AN ACTUAL, MARKET-BASED CAPITAL STRUCTURE?

A. Yes. OTP is a legally separate, wholly-owned subsidiary of Otter Tail Corporation. OTP has its own separate capital structure, its own short-term credit facility, and issues long-term debt securities in private placements to institutional investors. OTP's capital structure is subject to capital market scrutiny from credit rating agencies and institutional investors.

Q. PLEASE DESCRIBE THE SCRUTINY OF CREDIT RATING AGENCIES AND INSTITUTIONAL INVESTORS.

A. OTP has separate, senior unsecured debt ratings from Fitch and S&P, while Moody's issues Corporate Credit/Long-Term Issuer Default Rating (as do S&P and Fitch). Institutional investors conduct significant due diligence on OTP in the process of determining whether, and at what price (and resulting interest rate), to purchase debt issued by OTP. Ultimately, because OTP is a separate legal entity with a separate credit facility and separately issued LTD (in private placements to institutional investors): (1) banks and investors recognize the importance of OTP's separate capital structure; and (2) OTP's capital structure is subject to capital market scrutiny from those banks and institutional investors.

Q. HOW DOES OTP'S PROPOSED EQUITY RATIO COMPARE TO THE EQUITY RATIOS OF THE COMPANY'S IN MS. BULKLEY'S COMPARABLE GROUP?

A. Ms. Bulkley's Direct Testimony shows that OTP's 53.50 percent equity ratio is well within the range of the equity ratios of companies in her comparable group. Ms. Bulkley notes the equity ratio range for her comparable group is 45.30 percent to 60.41 percent. OTP's proposed 53.50 percent equity ratio is well within that range.

Q. HOW DOES OTP'S PROPOSED EQUITY RATIO RELATE TO ITS CAPITAL EXPENDITURE PLAN?

A. OTP has been engaged in a substantial capital expenditure program that began in 2012 and is projected to continue through 2027, as discussed above. OTP's equity ratio is needed to support this program and maintain strong senior unsecured credit ratings, as I explained earlier in my Direct Testimony.

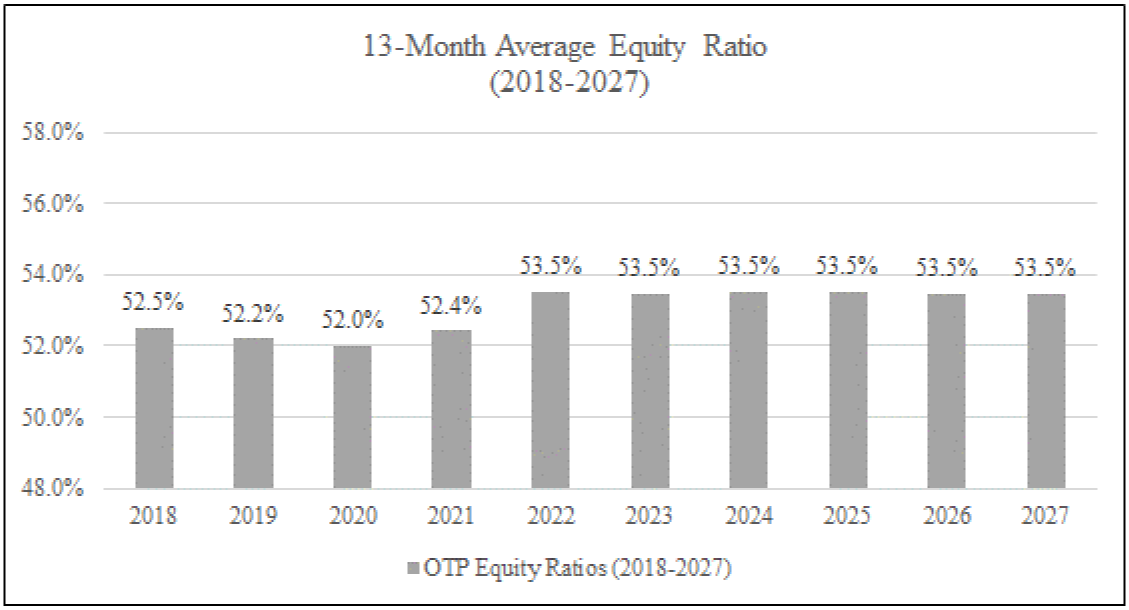
Q. HOW HAS OTP FINANCED THIS CAPITAL EXPENDITURE PLAN?

A. OTP has sought to maintain a balanced capital structure as it has undertaken these investments, relying on a combination of retained earnings, equity infusions from Otter Tail Corporation and LTD issuances. Historical retained earnings and equity infusions are shown in Table 3, above. Between 2018 and 2023, OTP issued approximately $355 million of LTD (net of retirements).

Q. HAS OTP'S EQUITY RATIO INCREASED OVER TIME AS ITS CAPITAL EXPENDITURE PLAN HAS PROGRESSED?

A. Yes. Given the scope of OTP's capital expenditure plan, OTP has determined it is prudent to strengthen its balance sheet to support its investment plans and help maintain strong senior unsecured credit ratings. Thus, OTP's equity ratio has increased over time through a mixture of retained earnings and equity infusions from Otter Tail Corporation, as shown in Table 3. OTP's equity ratio is projected to remain at 2024 levels going forward, as shown in the figure below.

Figure 1
OTP 13-Month Average Equity Ratios



Q. ARE THERE OTHER REASONS FOR OTP TO HAVE STRENGTHENED ITS BALANCE SHEET?

A. Yes. OTP must be able to access capital at a reasonable cost to finance both investments and operations. Further, this access must occur in a variety of economic conditions. Recent events, including the COVID-19 pandemic, Winter Storms Uri and Elliott, and bank failures in 2023 all severely impacted different aspects of the financial system. Further, different structural changes like sustained higher energy prices, greater sales volatility, supply chain challenges and inflation affect the conditions under which OTP is able to access the financial markets. By strengthening OTP's balance sheet, we are able to better meet those changes and continue to maintain access to capital at reasonable costs.

B. Long-Term Debt

Q. PLEASE DESCRIBE OTP'S LTD ISSUANCES.

A. As discussed above, OTP issues LTD securities in private placements to institutional investors. OTP has not issued public LTD.

Q. WHY DOES OTP ISSUE LTD THROUGH PRIVATE PLACEMENTS?

A. Our LTD offerings have been through private placements with institutional investors because the amounts placed by OTP at any single time are too small for an economic public issuance.

Q. WHAT ARE THE AMOUNT AND COST OF OTP'S LTD FOR THE 2024 TEST YEAR?

A. The 13-month average of OTP's LTD is $844.3 million and the cost of LTD is 4.65 percent for the 2024 Test Year, as shown on Exhibit___(TRW-1), Schedule 3.

Q. HOW DO THE COST AND AMOUNT OF LTD COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. As shown in the table below, the overall cost of LTD has decreased by approximately 70 basis points and the amount of OTP's LTD has increased by approximately $351.2 million.

Table 6
OTP LTD (2018 North Dakota Rate Case and Current Case)
($ millions)

	2018 North Dakota Rate Case[26]	**Current Rate Case**	**Difference**
Amount	$493.1	$844.3	$351.2
Cost	5.35%	4.65%	-0.70%

Q. PLEASE SUMMARIZE OTP'S LTD PLACEMENTS SINCE ITS LAST NORTH DAKOTA RATE CASE.

A. Since January 1, 2019, OTP has placed a total of $405.0 million of new LTD, and has retired $170.0 million of LTD. The average cost of LTD placed since January 1, 2019 is 3.56 percent.

Q. HOW HAVE THESE LTD PLACEMENTS RELATED TO THE LONG-TERM FINANCING OF OTP'S CAPITAL EXPENDITURES?

A. These LTD placements, along with OTP retained earnings and equity infusions from Otter Tail Corporation, were used to replace STD incurred during construction and to maintain a reasonable long-term capital structure for OTP.

[26] *Otter Tail Power Company 2017 Electric Rate Increase Application*, ND PSC Case No. PU-17-398, Supplemental Direct Testimony of Kevin G. Moug, Updated Schedule 2 (Mar. 23, 2018).

C. Short-Term Debt

Q. WHAT ARE THE AMOUNT AND COST OF OTP'S STD FOR THE 2024 TEST YEAR?

A. The 13-month average of OTP's STD is $57.8 million, and the cost of STD is 5.25 percent, as shown on Exhibit___(TRW-1), Schedule 4.

Q. HOW WAS THE COST OF STD DETERMINED?

A. The 5.25 percent cost of STD includes the estimated interest expense plus the monthly commitment and other fees associated with OTP's short-term credit facility. OTP can update the STD as the case develops so that final rates will be based on a combination of the actual data that is available and updated forecasts of STD interest rates.

Q. HOW DO THE COST AND AMOUNT OF STD COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. As shown in the table below, the overall cost of STD has increased by approximately 141 basis points and the amount of OTP's STD has increased by approximately $39.6 million.

Table 7
OTP STD (2018 North Dakota Rate Case and Current Case)
($ millions)

	2018 North Dakota Rate Case[27]	Current Rate Case	Difference
Amount	$17.6	$57.5	$39.7
Cost	3.84%	5.25%	1.41%

Q. WHAT IS CONTRIBUTING TO THE INCREASE IN THE AMOUNT OF THE COST OF STD?

A. As shown in the figure below, short-term interest rates have increased substantially since OTP's last North Dakota rate case, with the Secured Overnight Financing Rate (SOFR) increasing from 1.80 percent in April 2018 to 5.31 percent as of September 5, 2023. OTP's STD facility is priced according to SOFR, so the increase in the underlying index has directly caused an increase in the cost of STD.

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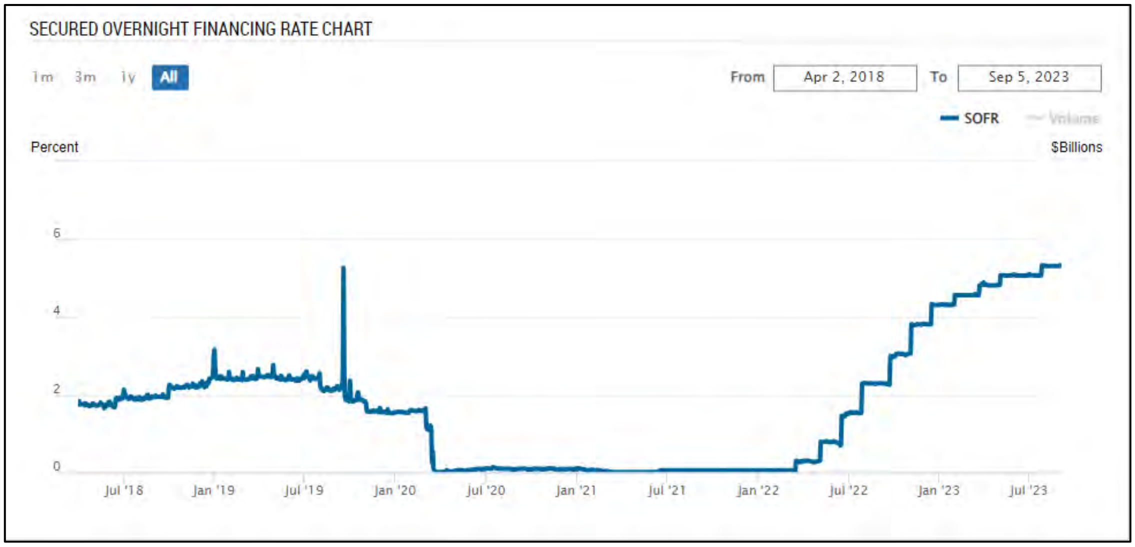
[27] *Otter Tail Power Company 2017 Electric Rate Increase Application*, ND PSC Case No. PU-17-398, Supplemental Direct Testimony of Kevin G. Moug, Updated Schedule 2 (Mar. 23, 2018).

Figure 2
Secured Overnight Financing Rate – 2018 – 2023[28]



Q. ARE THERE OTHER FACTORS THAT CONTRIBUTE TO THE COST OF STD?

A. Yes. Both the margin above SOFR and the commitment fee on OTP's short term credit facility are dependent on OTP's credit ratings. If credit ratings were to deteriorate, then the cost of STD would increase. This is another way in which maintaining OTP's financial strength and integrity directly benefits customers – though lower STD costs.

D. Common Equity

Q. WHAT IS THE AMOUNT OF COMMON EQUITY IN THE PROPOSED 2024 TEST YEAR CAPITAL STRUCTURE AND HOW WAS IT DETERMINED?

A. OTP's common equity is $1.037 billion, which reflects the average of 13 month-end expected equity balances from December 2023 through December 2024. Exhibit___(TRW-1), Schedule 5 shows the 2024 Test Year equity balance by month.

[28] Federal Reserve Bank of New York, Secured Overnight Financing Rate Data, https://www.newyorkfed.org/markets/reference-rates/sofr (last accessed September 6, 2023).

Q. HOW DOES THE PROPOSED COMMON EQUITY LEVEL COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. The $1.037 billion common equity balance is $472 million (approximately 83 percent) greater than the $565 million balance in our last North Dakota rate case, as shown in Table 8 below:

Table 8
OTP Common Equity (2018 North Dakota Rate Case and Current Case)
($ millions)

	2018 North Dakota Rate Case[29]	Current Rate Case	Difference
Amount	$565	$1,037	$472

Q. PLEASE DESCRIBE OTTER TAIL CORPORATION'S STOCK ISSUANCES SINCE 2004.

A. Since 2004, Otter Tail Corporation has utilized its At the Market Program (ATM), Employee Stock Purchase Plan (ESPP) and Dividend Reinvestment Plan (DRIP) for public issuance of its common stock. Otter Tail Corporation also had secondary offerings in 2004-2005 and in 2008. Detailed information showing the type of issuance (ESPP, DRIP, ATM, and Secondary) by year is included in Exhibit___(TRW-1), Schedule 6.

Q. ARE THERE COSTS ASSOCIATED WITH THESE ISSUANCES?

A. Yes. When common stock is issued, the corporation issuing the stock incurs costs in the process of issuance, including underwriter discounts, audit, legal, printing and listing fees, and other expenses of issuance. When these issuance costs (also known as "flotation costs") are incurred, they reduce the net proceeds received by the corporation issuing the stock (under generally accepted accounting principles). Flotation costs are comparable to the issuance costs for LTD. The flotation costs associated with Otter Tail Corporation's common stock issuances are identified in Exhibit___(TRW-1), Schedule 6. Ms. Bulkley has taken these costs into account in making her ROE recommendation. All of these flotation costs were treated as a reduction in proceeds and reflected on the balance sheet and not expensed, which is the standard practice with all flotation costs.

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[29] *Otter Tail Power Company 2017 Electric Rate Increase Application*, ND PSC Case No. PU-17-398, Supplemental Direct Testimony of Kevin G. Moug, Updated Schedule 2 (Mar. 23, 2018).

Q. HAVE THESE COMMON STOCK ISSUANCES BY OTTER TAIL CORPORATION BEEN RELATED TO OTP'S CAPITAL EXPENDITURES?

A. Yes. These Otter Tail Corporation common stock issuances are directly related to OTP's prior, current, and planned future capital expenditures.

Q. WERE THESE EQUITY ISSUANCES NECESSARY FOR OTTER TAIL CORPORATION TO PROVIDE THE EQUITY INFUSIONS NEEDED BY OTP?

A. Yes. These equity issuances were needed for Otter Tail Corporation to fund the equity infusions required by OTP.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the Commission approve a capital structure for the 2024 Test Year consisting of 53.50 percent equity, 43.52 percent LTD, and 2.98 percent STD. I also recommend that the Commission approve an ROE of 10.60 percent and an overall ROR of 7.85 percent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TODD R. WAHLUND

EMPLOYMENT

2018-PRESENT Otter Tail Power Company — Fergus Falls, MN
Chief Financial Officer

2017-2018 Otter Tail Corporation — Fergus Falls, MN
VP, Financial Planning and Treasurer

2012-2017 Otter Tail Corporation — Fargo, ND
VP, Finance, Planning, and M&A

2012 Otter Tail Power Company — Fergus Falls, MN
VP, Energy Trading and Planning

2008-2012 Otter Tail Power Company — Fergus Falls, MN
VP, Resource Planning and Risk Management

2004-2008 Otter Tail Power Company — Fergus Falls, MN
Director, Risk Management and Business Planning

2002-2004 Otter Tail Power Company — Fergus Falls, MN
Manager, Business Planning

2001-2002 Otter Tail Power Company — Fergus Falls, MN
Manager, Financial Analysis

1992-2001 Otter Tail Power Company — Fergus Falls, MN
Various financial and operational roles

EDUCATION

- Bachelor of Science in Accounting — Minnesota State University-Moorhead
- Masters in Business Administration — University of North Dakota

INDUSTRY CERTIFICATIONS

- Certified Public Accountant (Inactive)
- Certified Management Accountant
- Certified in Financial Management

PROFESSIONAL AFFILIATIONS

- Institute of Management Accountants — Member

PROPOSED COST OF CAPITAL FOR 2024 TEST YEAR

Line No.	(A) Capitalization	(B) Amount	(C) Percent of Total	(D) Cost of Capital	(E) Weighted Cost of Capital
1	Short term debt	$57,841,876	2.98%	5.25%	0.16%
2	Long term debt	844,276,579	43.52%	4.65%	2.02%
3	Total debt	$902,118,455	46.50%	4.68%	2.18%
4	Common equity	$1,037,715,501	53.50%	10.60%	5.67%
5	Total Capitalization	$1,939,833,956	100.00%		7.85%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota

Case No. PU-23-
Exhibit ___(TRW-1), Schedule 3

COMPOSITE COST OF LONG-TERM DEBT FOR 2024 TEST YEAR

Line	DESCRIPTION	Interest	PRINCIPAL AMOUNTS OUTSTANDING														
No.	**Bonds/Debentures**	Rate	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total (avg)	Interest Cost
1	Debenture -Unsecured Series C 2027 Senior Notes - 6.37% - 09-01-27	6.370%	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$42,000,000	$2,675,400
2	Debenture -Unsecured Series D 2037 Senior Notes - 6.47% - 08-31-37	6.470%	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	$50,000,000	$3,235,000
3	Forecasted Long Term Debt	6.300%	0	0	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	120,000,000	$101,538,462	$6,689,999
4	Unsecured Series A 2029 4.68% - 2-27-29	4.680%	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	$60,000,000	$2,808,000
5	Unsecured Series A 2029 Senior Note - 3.07% - 10-10-2029	3.070%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	$10,000,000	$307,000
6	Unsecured Series A 2030 Senior Note - 3.22% - 02-25-2030	3.220%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	$10,000,000	$322,000
7	Unsecured Series A 2031 Senior Note - 2.74% - 11-29-2031	2.740%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	$40,000,000	$1,096,000
8	Unsecured Series A 2048 4.07% - 02-07-48	4.070%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	$100,000,000	$4,070,000
9	Unsecured Series B 2030 Senior Note - 3.22% - 08-20-2030	3.220%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	$40,000,000	$1,288,000
10	Unsecured Series B 2039 Senior Note - 3.52% - 10-10-2039	3.520%	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	26,000,000	$26,000,000	$915,200
11	Unsecured Series B 2044 5.47% - 2-27-44	5.470%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	$90,000,000	$4,923,000
12	Unsecured Series B 2051 Senior Note - 3.69% - 11-29-2051	3.690%	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	100,000,000	$100,000,000	$3,690,000
13	Unsecured Series C 2040 Senior Note - 3.62% - 02-25-2040	3.620%	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	$10,000,000	$362,000
14	Unsecured Series C 2049 Senior Note - 3.82% - 10-10-2049	3.820%	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	64,000,000	$64,000,000	$2,444,800
15	Unsecured Series C 2052 Senior Note - 3.77% - 05-20-2052	3.770%	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	$90,000,000	$3,393,000
16	Unsecured Series D 2050 Senior Note - 3.92% - 02-25-2050	3.920%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	$15,000,000	$588,000
17	Subtotal Bond Balances		**$747,000,000**	**$747,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$867,000,000**	**$848,538,462**	**$38,807,399**
	Amortization of Reacquired Debt		(230,363)	(229,257)	(228,309)	(227,519)	(226,887)	(226,413)	(226,097)	(225,939)	(225,939)	(225,939)	(225,939)	(225,939)	(225,939)	(225,939)	
	Unamortized Debt Expense		(3,420,752)	(3,390,094)	(3,451,490)	(3,512,633)	(3,569,888)	(3,626,957)	(3,683,840)	(3,740,397)	(3,800,274)	(3,859,766)	(3,918,875)	(3,977,601)	(4,035,943)	(4,035,943)	$411,807
	Total Long-Term Debt Capital		**$743,348,885**	**$743,380,649**	**$863,320,201**	**$863,259,848**	**$863,203,225**	**$863,146,630**	**$863,090,063**	**$863,033,663**	**$862,973,787**	**$862,914,295**	**$862,855,185**	**$862,796,460**	**$862,738,118**	**$844,276,579**	**$39,219,206**

WEIGHTED COST OF LONG-TERM DEBT **4.65%**

Short-term Debt

			Cost of Short-Term Debt		
Line No.	Month	Month end balances	Monthly Interest Expense	Monthly Fee Expense	Average Short-Term Debt Cost
1	2023 Dec	98,911,504			
2	2024 Jan	149,149,431	540,566	14,958	
3	2024 Feb	17,591,775	363,357	15,422	
4	2024 Mar	34,081,902	112,606	15,597	
5	2024 Apr	45,979,848	174,468	15,764	
6	2024 May	62,944,014	237,363	15,641	
7	2024 Jun	-	125,928	16,090	
8	2024 Jul	8,695,135	7,710	16,555	
9	2024 Aug	33,526,371	92,008	16,811	
10	2024 Sep	57,349,005	198,033	16,698	
11	2024 Oct	65,252,487	267,169	41,755	
12	2024 Nov	77,590,726	311,279	16,680	
13	2024 Dec	100,872,190	388,900	16,429	
14	Average	$57,841,876			
15	Total $ Cost		2,819,387	218,400	3,037,786
16	Total % Cost		4.87%	0.38%	5.25%

COMMON EQUITY FOR 2024 TEST YEAR

		Month-end Balances		
Line No.		CONTRIBUTED CAPITAL	RETAINED EARNINGS	TOTAL COMMON EQUITY
1	December 2023	676,988,966	293,355,899	970,344,864
2	January	676,988,966	303,696,641	980,685,607
3	February	676,988,966	311,730,502	988,719,467
4	March	676,988,966	299,325,135	976,314,101
5	April	676,988,966	304,353,091	981,342,057
6	May	676,988,966	309,527,405	986,516,371
7	June	777,688,966	298,110,693	1,075,799,658
8	July	777,688,966	306,796,656	1,084,485,621
9	August	777,688,966	315,043,241	1,092,732,206
10	September	777,688,966	304,696,104	1,082,385,070
11	October	777,688,966	310,267,971	1,087,956,937
12	November	777,688,966	318,387,151	1,096,076,116
13	December	777,688,966	309,254,458	1,086,943,424
14	Average Common Equity			$1,037,715,501

OTTER TAIL POWER COMPANY | **Case No. PU-23-**
Electric Utility - State of North Dakota | **Exhibit ___(TRW-1), Schedule 6**

Floation Costs

Line No.	Issuing Entity	Mechanism	Date	Shares issued	Offering Price (1)	Underwriting Discount	Offering Expense	Gross Proceeds	Total Flotation Costs	Net Proceeds	Flotation cost %
1	Otter Tail Corp.	ESPP	2004	66,958	NA	$ -	$ -	$ 1,292,959	$ -	$ 1,292,959	0.00%
2	Otter Tail Corp.	ESPP	2009	62,450	NA	$ -	$ -	$ 1,197,791	$ -	$ 1,197,791	0.00%
3	Otter Tail Corp.	ESPP	2014	39,222	NA	$ -	$ -	$ 1,049,188	$ -	$ 1,049,188	0.00%
4	Otter Tail Corp.	ESPP	2015	42,253	NA	$ -	$ -	$ 1,095,620	$ -	$ 1,095,620	0.00%
5	Otter Tail Corp.	ESPP	2016	53,875	NA	$ -	$ -	$ 1,491,266	$ 1,159	$ 1,490,107	0.08%
6	Otter Tail Corp.	ESPP	2017	5,284	NA	$ -	$ -	$ 210,585	$ 367	$ 210,218	0.17%
7	Otter Tail Corp.	ESPP	2019	15,418	NA	$ -	$ 836	$ 683,084	$ 836	$ 682,248	0.12%
8	Otter Tail Corp.	ESPP	2020	24,368	NA	$ -	$ 1,544	$ 874,784	$ 1,544	$ 873,240	0.18%
9	Otter Tail Corp.	ESPP	2021	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
10	Otter Tail Corp.	ESPP	2022	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
11	Otter Tail Corp.	ESPP	2023 - YTD	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
12	Otter Tail Corp.	DRIP	2004	223,165	NA	$ -	$ -	$ 4,308,033	$ -	$ 4,308,033	0.00%
13	Otter Tail Corp.	DRIP	2009	233,943	NA	$ -	$ -	$ 4,493,385	$ 5,877	$ 4,487,508	0.13%
14	Otter Tail Corp.	DRIP	2014	288,045	NA	$ -	$ -	$ 7,707,964	$ -	$ 7,707,964	0.00%
15	Otter Tail Corp.	DRIP	2015	330,379	NA	$ -	$ 56,545	$ 8,566,009	$ 56,545	$ 8,509,464	0.66%
16	Otter Tail Corp.	DRIP	2016	302,524	NA	$ -	$ -	$ 11,095,328	$ 32,973	$ 11,062,355	0.30%
17	Otter Tail Corp.	DRIP	2017	107,285	NA	$ -	$ -	$ 4,139,552	$ 17,554	$ 4,121,998	0.42%
18	Otter Tail Corp.	DRIP	*2019	51,352	NA	$ -	$ 7,125	$ 2,545,820	$ 7,125	$ 2,538,695	0.28%
19	Otter Tail Corp.	DRIP	2020	190,678	NA	$ -	$ 20,931	$ 8,014,920	$ 20,931	$ 7,993,989	0.26%
20	Otter Tail Corp.	DRIP	2021	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
21	Otter Tail Corp.	DRIP	2022	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
22	Otter Tail Corp.	DRIP	2023 - YTD	-	NA	$ -	$ -	$ -	$ -	$ -	0.00%
23	Otter Tail Corp.	ATM	2014	519,636	$ 30	$ 306,727	$ 780,616	$ 15,336,352	$ 1,087,343	$ 14,249,009	7.09%
24	Otter Tail Corp.	ATM	2015	133,197	$ 28	$ 56,485	$ 339,160	$ 3,785,244	$ 395,645	$ 3,389,599	10.45%
25	Otter Tail Corp.	ATM	2016	1,014,115	$ 33		$ 561,548	$ 33,235,729	$ 561,548	$ 32,674,181	1.69%
26	Otter Tail Corp.	ATM	2019	372,000	$ 51	$ 577,130	$ 237,218	$ 18,957,301	$ 814,348	$ 18,142,953	4.30%
27	Otter Tail Corp.	ATM	2020	843,484	$ 43	$ -	$ 452,229	$ 36,178,362	$ 452,229	$ 35,726,133	1.25%
28	Otter Tail Corp.	Secondary	2004-05	3,075,000	$ 25	$ 2,921,250	$ 391,452	$ 78,258,750	$ 3,312,702	$ 74,946,048	4.23%
29	Otter Tail Corp.	Secondary	2008	5,175,000	$ 30	$ 5,627,812	$ 807,185	$ 155,250,000	$ 6,434,997	$ 148,815,003	4.14%
30	Weighted Average										3.30%

Volume 2B

Direct Testimony and Supporting Schedules:

Ann E. Bulkley

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___(AEB-1)

RETURN OF EQUITY

Direct Testimony and Schedules of

ANN E. BULKLEY

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

Schedule	Description
Schedule 1	Resume and Testimony Listing of Ann E. Bulkley
Schedule 2	Summary of Results
Schedule 3	Proxy Group Selection
Schedule 4	Constant Growth DCF Model
Schedule 5	Capital Asset Pricing Model / Empirical Capital Asset Pricing Model
Schedule 6	Long-Term Average Beta
Schedule 7	Market Return
Schedule 8	Risk Premium Approach
Schedule 9	Small Size Premium
Schedule 10	Trading Volumes
Schedule 11	Institutional Ownership
Schedule 12	Capital Expenditure Analysis
Schedule 13	Regulatory Risk Analysis
Schedule 14	Flotation Costs
Schedule 15	Capital Structure Analysis

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group (Brattle). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND, AS WELL AS YOUR BUSINESS AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my qualifications and a summary of testimony that I have filed in other proceedings as Exhibit___(AEB-1), Schedule 1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting this direct testimony before the North Dakota Public Service Commission (Commission) on behalf of Otter Tail Power Company (OTP or the Company), a wholly-owned subsidiary of Otter Tail Corporation (OTTR).

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity (ROE) for OTP and to provide an assessment of the capital structure to be used for ratemaking purposes.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES IN SUPPORT OF YOUR DIRECT TESTIMONY?

A. Yes. My analyses and recommendations are supported by the data presented in Exhibit___(AEB-1), Schedules 2 through 15.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE RECOMMENDATION?

A. I have estimated the Company's cost of equity by applying several traditional estimation methodologies to a proxy group of comparable utilities, including 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 takes into consideration the following factors: (1) the Company's small size; (2) limited trading volume; (3) limited institutional ownership; (4) OTP's customer concentration; (5) the Company's capital expenditure requirements; (6) the regulatory environment in which the Company operates; (7) flotation costs; and (8) the Company's proposed capital structure as compared to the capital structures of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

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

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section V discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section VI explains my selection of the proxy group for the Company.

- Section VII describes my analyses and the basis for my recommended ROE in this proceeding.
- Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized in this proceeding.
- Section IX assesses the proposed capital structure as compared to the proxy group.
- Section X presents my conclusions and recommendations for the market cost of equity.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. WHAT IS YOUR RECOMMENDED ROE FOR OTP IN THIS PROCEEDING?

A. Considering the analytical results presented in Figure 2, below, and discussed further throughout my testimony, current and prospective capital market conditions, as well as the level of risk faced by OTP's operations in North Dakota relative to the proxy group, I conclude that the range of reasonable ROEs for OTP is 10.00 to 11.00, and within that range, I recommend an ROE of 10.60 percent.

Q. IS OTP'S REQUESTED CAPITAL STRUCTURE REASONABLE AND APPROPRIATE?

A. Yes. The Company's proposed equity ratio of 53.50 percent is within the range of equity ratios for the proxy group. Further, the Company's proposed equity ratio is reasonable considering credit rating agencies' continued concern with the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and capital expenditures.

Q. PLEASE SUMMARIZE THE KEY FACTORS CONSIDERED IN YOUR ANALYSES AND UPON WHICH YOU BASE YOUR RECOMMENDED ROE.

A. The key factors that I considered in my cost of equity analyses and recommended ROE for the Company in this proceeding are:

- The United States Supreme Court's *Hope* and *Bluefield* decisions,[1] which 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.
- 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).
- The Company's risks relative to the proxy group of comparable companies and the implications of those risks.

Q. ARE CURRENT CAPITAL MARKET CONDITIONS DIFFERENT THAN THOSE PRESENT DURING THE COMPANY'S LAST NORTH DAKOTA RATE CASE?

A. Yes. As shown in Figure 1, when the Commission authorized a settlement ROE of 9.77 percent in the Company's last North Dakota rate case (Case No. PU-17-398), interest rates (as measured by the 30-year Treasury bond yield) were 3.09 percent and inflation was 2.20 percent. Since then, long-term interest rates have increased over 80 basis points as the Federal Reserve has increased the federal funds rate to combat inflation, which, as shown in Figure 1, also is significantly higher than during the Company's last rate case, and, as noted, remains above the Federal Reserve's target. As I will discuss in more detail below, I considered this change in

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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").

market conditions as well as expected market conditions during the rate period in determining my recommended ROE for OTP.

Figure 1: Change in Market Conditions Since the Company's Last Rate Case[2]

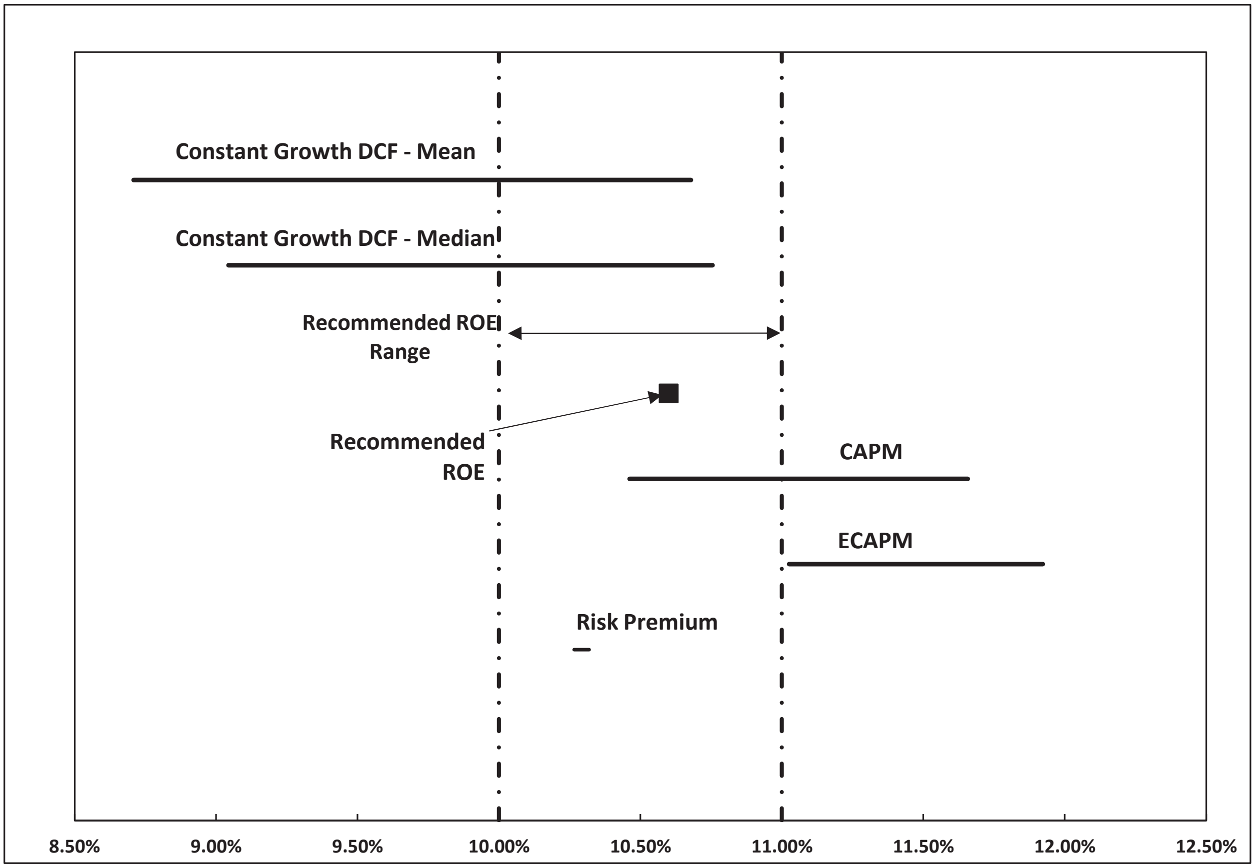
Case	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Inflation Rate	Auth'd ROE
PU-17-398	9/26/2018	1.95%	3.09%	2.20%	9.77%
Current	7/31/2023	5.12%	3.92%	4.70%	

Q. WHAT ARE THE RESULTS OF THE MODELS THAT YOU HAVE USED TO ESTIMATE THE COST OF EQUITY FOR OTP?

A. Figure 2 summarizes the range of results produced by the constant growth DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analysis.

[2] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

Figure 2: Summary of Cost of Equity Analytical Results



As shown in Figure 2, the range of results across all methodologies is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q. ARE PROSPECTIVE CAPITAL MARKET CONDITIONS EXPECTED TO AFFECT THE RESULTS OF THE COST OF EQUITY FOR THE COMPANY DURING THE PERIOD IN WHICH THE RATES ESTABLISHED IN THIS PROCEEDING WILL BE IN EFFECT?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.

- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least through the test year, and likely beyond that time frame, in response to inflation.
- Equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the next year.
- The utility sector is expected to underperform because: (1) utility dividend yields are now less attractive than the risk-free rates of government bonds; (2) interest rates are expected to remain near current levels over the few years; and (3) utility stock prices are inversely related to changes in interest rates.
- If utility stock prices decline as expected then the dividend yields of utilities will increase and thus, all else equal, so too will the cost of equity estimates produced by the DCF model.
- Consequently, the results of the DCF model, which relies on current utility share prices, likely understates the cost of equity during the period that the Company's rates will be in effect.
- Furthermore, expected market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which rely on interest rates as a direct input into the models and thus may better reflect the market expected during the period that the Company's rates will be in effect.
- Rating agencies have cited increased risk in the utility sector due to increased interest rates, inflation and elevated capital expenditures.

IV. REGULATORY PRINCIPLES AND GUIDELINES

Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. 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 authorized 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) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

Q. HOW DID THE COURT CONNECT THE ACHIEVEMENT OF A FAIR RATE OF RETURN TO THE PROVISION OF UTILITY SERVICE?

A. In *Bluefield*, the Court noted 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."[4] As the Court further explained in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN AN ROE THAT IS ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. An authorized ROE that is adequate to attract capital at reasonable terms enables the utility to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable risk. It is important to recognize that equity investors have a choice of where to invest capital. If the authorized ROE is not comparable to the returns available for comparable risk investments, it is not just the value to current equity holders that will be harmed, but rather, access to incremental equity is also affected. It is reasonable to expect that equity investors will seek alternative investment

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3 *Hope,* 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

4 *Bluefield*, 262 U.S. at 679, 693.

5 *Hope*, 320 U.S. at 591, 603.

opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract new equity capital at reasonable cost.

Q. IS A UTILITY'S ABILITY TO ATTRACT CAPITAL ALSO AFFECTED BY THE ROES THAT ARE AUTHORIZED FOR OTHER UTILITIES?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. 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. Put another way: the cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable or lower 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.

Q. IS THE REGULATORY FRAMEWORK, INCLUDING THE AUTHORIZED ROE AND EQUITY RATIO, IMPORTANT TO THE FINANCIAL COMMUNITY?

A. Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q. WHAT IS THE STANDARD FOR SETTING THE ROE IN ANY JURISDICTION?

A. The stand-alone ratemaking principle is the 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. In order to maintain 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 the OTP's electric operations in North Dakota.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING REGULATORY GUIDELINES?

A. 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. This is particularly true for utilities, which are capital-intensive operations and are required to make investments in a variety of economic and financial market conditions. Preserving that ability benefits both investors and customers.

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.

V. CAPITAL MARKET CONDITIONS

Q. IS IT IMPORTANT TO ANALYZE CURRENT AND PROSPECTIVE CAPITAL MARKET CONDITIONS?

A. Yes. The models used to estimate the cost of equity rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses both current and projected market data, specifically stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. Accordingly, it is important to consider the effect of these conditions on the models when determining an appropriate range for the ROE and the 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 very important to consider projected market data to estimate the return for that forward-looking period.

Q. IS THIS RELATIONSHIP BETWEEN CURRENT AND FUTURE MARKET CONDITIONS PARTICULARLY IMPORTANT IN THIS CASE?

A. Yes. As discussed in more detail below, interest rates have increased significantly since the end of 2021 as the Federal Reserve normalized monetary policy to combat inflation. Empirical evidence demonstrate a strong inverse relationship between utility stock prices and interest rates, however, while utility valuations have declined since July 2022, utility valuations still do not fully reflect the effect in the recent increase in interest rates. For example, the dividend yields of utilities are still below the yields on long-term government bonds when historically the dividend yields of utilities have exceeded the yields on long-term government bonds. Given that interest rates are expected to remain elevated over the next few years, it is reasonable to expect the share prices of utilities will continue to decline as the difference between the dividend yields of utility stocks and the yields on long-term government bonds (yield spread) normalizes to historical levels. These declining share prices will put upward pressure on dividend yields and thus, the cost of equity measured by the DCF model. As a result, DCF models, which rely on recent historical share price data, most likely currently are understating investors' required return over the period that OTP's rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

Q. WHAT FACTORS ARE AFFECTING THE COST OF EQUITY FOR REGULATED UTILITIES IN THE CURRENT AND PROSPECTIVE CAPITAL MARKETS?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q. WHAT EFFECT DO CURRENT AND PROSPECTIVE MARKET CONDITIONS HAVE ON THE COST OF EQUITY FOR OTP?

A. Historically, there has been a strong, inverse correlation between interest rates (*i.e.*, yields on long-term government bonds) and the share prices of utility stocks (*i.e.*, as utility share prices decline, utility dividend yields increase). Since the yields on long-term government bonds currently exceed the dividend yields of utilities, and historically, long-term government bond yields have been lower than the dividend yields of utilities, it is reasonable to expect that utility investors' required returns for investing in utility stocks is increasing.

Q. HOW DOES THAT AFFECT THE COST OF EQUITY ANALYSIS IN THIS PROCEEDING?

A. Because the cost of equity in this proceeding is being estimated for the future period during which the Company's rates will be in effect, and because the cost of equity is expected to increase over the near term for utilities, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, likely will understate the cost of equity during the future period that the Company's rates will be in effect.

Q. HOW WOULD YOU CHARACTERIZE THE MARKET CONDITIONS EXPECTED TO BE IN PLACE DURING THE FUTURE PERIOD THAT THE COMPANY'S RATES WILL BE IN EFFECT?

A. As is discussed in more detail in the remainder of this section, inflation continues to exceed the Federal Reserve's target level. The Federal Reserve's change in monetary policy (form one of accommodation to one focused on combatting inflation) contributes to expectations of relatively elevated interest rates, increased market risk and an increase in the cost of the investor-required return. It is important that these factors be considered in setting a forward-looking ROE.

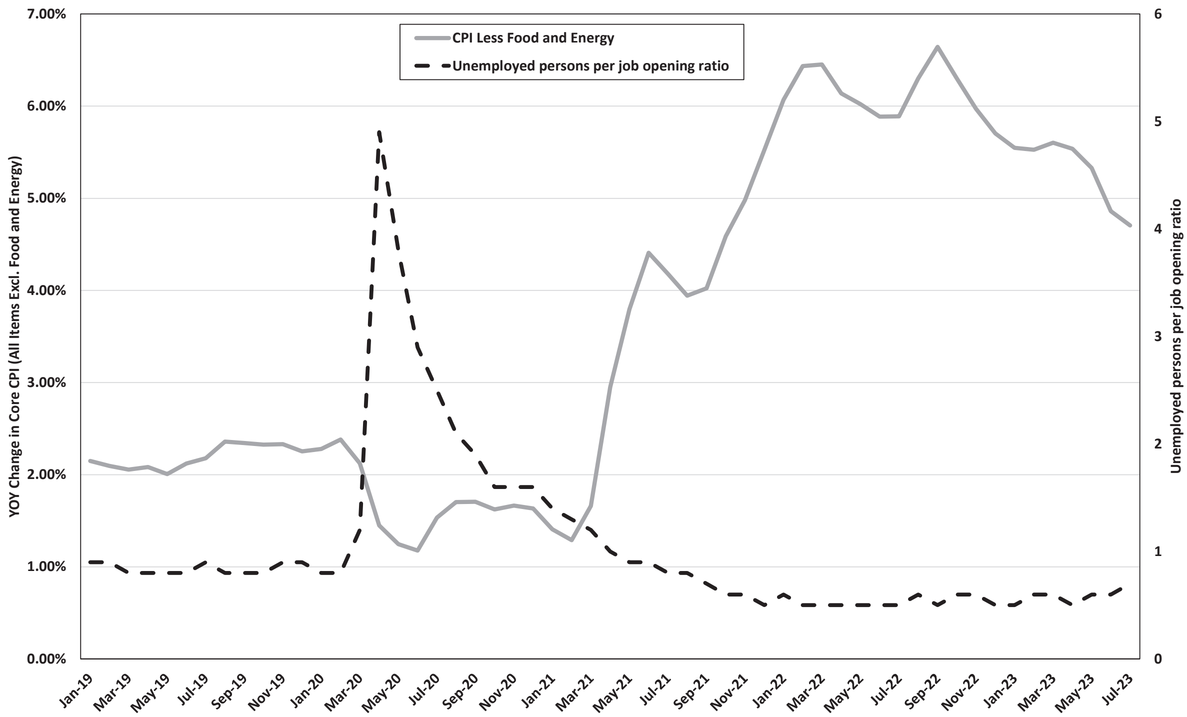
A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q. WHAT IS THE CURRENT LEVEL OF INFLATION IN THE ECONOMY?

A. While down from near 40-year highs, inflation remains at elevated levels. Figure 3 presents the year-over-year (YOY) 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.[6] As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982. While core inflation has declined from the 40-year high in response to the Federal Reserve's monetary policy, it remains above the Federal Reserve's target level of 2.0 percent.

[6] I 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 since it removes the effect of food and energy prices, which can be highly volatile.

Figure 3: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 – July 2023[7]



Q. IS THE FEDERAL RESERVE STILL COMMITTED TO TAKING POLICY ACTIONS TO REDUCE INFLATION?

A. Yes. Despite the declines from 40-year highs, the Federal Reserve has indicated that it expects inflation will remain above its target level over at least the next year and that monetary policy will remain restrictive in order to reduce inflation. For example, Federal Reserve Chair Powell observed at the Federal Open Market Committee (FOMC) meeting in September 2023 that while inflation is down from its recent highs, it remains significantly above the Federal Reserve's long-term target:

> Inflation remains well above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [personal consumption expenditures] prices rose 3.4 percent over the 12 months ending in August; and that, excluding the volatile food and energy categories, core PCE prices rose 3.9 percent. Inflation has moderated somewhat since the middle of last year, and

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7 Bureau of Labor Statistics.

> longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. Nevertheless, the process of getting inflation sustainably down to 2 percent has a long way to go. The median projection in the SEP for total PCE inflation is 3.3 percent this year, falls to 2.5 percent next year, and reaches 2 percent in 2026.[8]

As a result, Federal Reserve Chair Powell noted that they intend to maintain a restrictive policy stance until substantial progress has been made to reduce inflation to the long-term target of 2 percent.[9] Moreover, the Federal Reserve is currently forecasting an additional 25 basis point increase in the federal funds rate in 2023.[10] Given the expectation that monetary policy will remain restrictive, as noted previously, yields on long-term government bonds are expected to remain elevated over the near-term.

B. The Use of Monetary Policy to Address Inflation

Q. WHAT POLICY ACTIONS HAS THE FEDERAL RESERVE ENACTED TO RESPOND TO INCREASED INFLATION?

A. The dramatic increase in inflation has 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. Since the March 2022 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases, from 0.00 – 0.25 percent to 5.25 – 5.50 percent.[11] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the

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8 Federal Reserve, Transcript of Chair Powell's Press Conference, September 20, 2023, p 2.

9 *Id.,* at 3.

10 Federal Reserve, Summary of Economic Projections, September 20, 2023, at 2.

11 Federal Reserve, Press Releases, March 16, 2022, May 4, 2022, June 15, 2022, September 22, 2022, November 2, 2022, February 1, 2023, March 22, 2023, May 3, 2023, July 26, 2023. Federal Reserve Board - Press Releases

federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

Q. IS THE FEDERAL RESERVE ABLE TO PURSUE THESE POLICY ACTIONS AND STILL FULFILL ITS DUAL MANDATE?

A. Yes. Figure 3 identifies the ratio of unemployed persons per job opening, which currently is 0.7 and has been consistently below 1.0 since 2021 despite the Federal Reserve's policy actions. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

C. The Effect of Inflation and Monetary policy on Interest Rates and the Investor-Required Return

Q. HAVE THE YIELDS ON LONG-TERM GOVERNMENT BONDS INCREASED IN RESPONSE TO INFLATION AND THE FEDERAL RESERVE'S NORMALIZATION OF MONETARY POLICY?

A. Yes. As the Federal Reserve has substantially increased the federal funds rate in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. As shown in Figure 4, since the FOMC's December 2021 meeting, the yield on 10-year Treasury bonds has more than doubled, increasing from 1.47 percent on December 15, 2021 to 3.97 percent at the end of July 2023.

Figure 4: 10-Year Treasury Bond Yield, January 2021 – July 2023[12]

Q. DO FINANCIAL MARKETS EXPECT LONG-TERM GOVERNMENT BOND YIELDS TO REMAIN AT ELEVATED LEVELS?

A. Yes. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the first quarter of 2025. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.80 percent through the first quarter of 2025.[13] It is reasonable to expect that if government bond yields remain elevated, the cost of equity will be higher than the levels experienced in the 2020 and 2021 lower interest rate environment.

12 S&P Capital IQ Pro.

13 *Blue Chip Financial Forecasts*, Vol. 48, No. 10, October 2, 2023, p. 2.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. ARE UTILITY SHARE PRICES CORRELATED TO CHANGES IN THE YIELDS ON LONG-TERM GOVERNMENT BONDS?

A. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[14]

Q. HOW DO EQUITY ANALYSTS EXPECT THE UTILITIES SECTOR TO PERFORM IN AN INCREASING INTEREST RATE ENVIRONMENT?

A. Equity analysts project that utilities will underperform the broader market in a high inflation, high interest rate environment. For example, Fidelity classifies the utility sector as underweight,[15] and Bank of America recently noted that it is "not so constructive on [u]tilities" given that the dividend yields for utilities are below the yields available on both long- and short-term government bonds.[16]

Q. WHY DO EQUITY ANALYSTS EXPECT THE UTILITY SECTOR TO UNDERPERFORM OVER THE NEAR-TERM?

A. As noted above, there is an empirically demonstrated, inverse relationship between utility stock prices and interest rates. Yet, despite substantial interest rate increases over the past year, the valuations of utilities have not fully reflected the effect of the recent increase in interest rates, resulting in a negative yield spread

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14 Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

15 Fidelity. "Third Quarter 2023 Investment Research Update." July 24, 2023.

16 Dumoulin-Smith, "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," September 6, 2023.

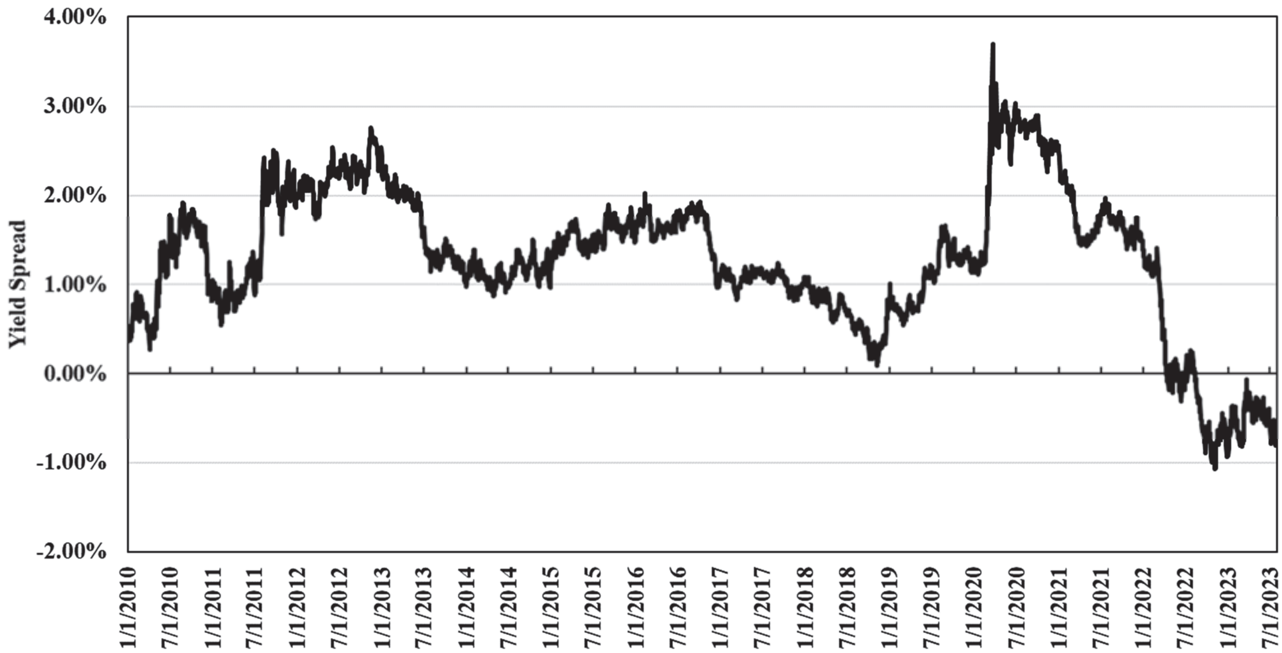
which is counter to the historical average spread that demonstrates the dividend yields of utilities have exceeded long-term government bonds. Therefore, it is reasonable to conclude that the current level of the yield spread is not sustainable over the long-term and will normalize to historical levels.

Q. WHY DO YOU CONSIDER THE CURRENT YIELD SPREAD TO BE UNSUSTAINABLE?

A. I examined the yield spread from January 2010 through July 2023, utilizing the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 5, the recent, significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of July 31, 2023 was negative 0.76 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.29 percent. Therefore, the current yield spread is well below the long-term average. Because the yield spread currently is well below the long-term average, and the expectation that interest rates will remain relatively high at least over the next few years, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated. The rotation away from utility stocks will result in a decrease in the share prices of utilities.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – July 2023[17]



Q. DO YOU HAVE ANY FURTHER CONTEXT AS TO HOW UNLIKELY IT IS TO HAVE A NEGATIVE YIELD SPREAD OF THIS MAGNITUDE?

A. Yes. For further context as to how unlikely it is to have a yield spread of negative 0.76 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of negative 0.76 percent has a z-score of -2.56,[18] indicating that a yield spread of negative 0.76 percent is over 2 standard deviations from the average yield spread from January 2010 through July 2023. In other words, 95 percent (*i.e.*, two standard deviations) of the daily yield spread observations over this period fall between -0.31 percent and 2.89 percent, with the current yield spread of negative

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17 S&P Capital IQ Pro and Bloomberg Professional.

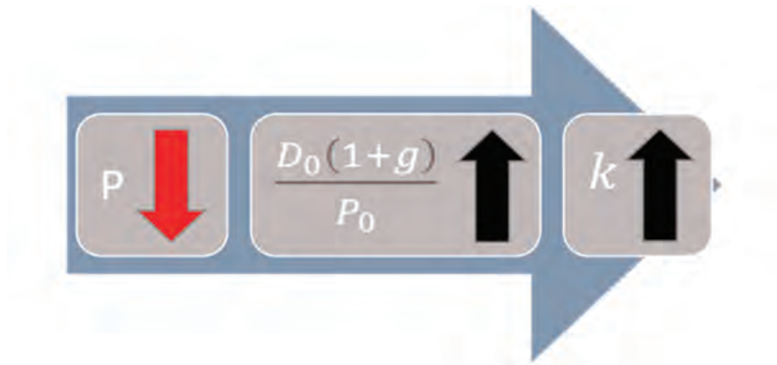
18 The z-score is calculated as: [the yield spread at July 31, 2023 minus the average yield spread January 2010 through July 2023] / standard deviation of yield spread from January 2010 through July 2023. The z-score equals: [-0.0076 minus 0.0129]/0.0080.

0.76 percent being outside of that range. Thus, the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

Q. WHAT IS THE SIGNIFICANCE OF THE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND UTILITY SHARE PRICES IN THE CURRENT MARKET?

A. If interest rates remain relatively high as expected, then the share prices of utilities would be expected to decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity. Figure 6 below summarizes the effect of price on the dividend yield in the Constant Growth DCF model.

Figure 6: The Effect of a Decline in Stock Prices on the Constant Growth DCF Model



Q. HAVE REGULATORY COMMISSIONS ACKNOWLEDGED THAT THE DCF MODEL MIGHT UNDERSTATE THE COST OF EQUITY GIVEN CURRENT CAPITAL MARKET CONDITIONS?

A. Yes. For example, in its May 2022 decision in establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission (PPUC) specifically concluded that the current capital market conditions of high inflation and increasing interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low

> interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[19]

More recently, the Massachusetts Department of Public Utilities (MDPU) also recently came to a similar conclusion:

> The Department recently considered the relationship between low interest rates and utility stock prices over the last several years and whether a projected increase in long-term interest rates caused the DCF analysis to understate the cost of equity. D.P.U. 20-120, at 416-419. The Department found that, although utility stocks had increased above historic levels in conjunction with low interest rates, the evidence in that proceeding that long-term interest rates would change was speculative. D.P.U. 20-120, at 417-419. In this proceeding, the record is clear that long-term interest rates have increased compared to the period of time from which the parties derived the dividend yields used in the DCF analyses (Exh. ES-VVR-Rebutal-1, at 23-26; Tr. 14, at 1463). We also have considered the Attorney General's evidence of investors forecasting that utility stocks will retain their high valuations in the near term (Tr. 14, at 1449-1452; RR-DPU-48). ***Based on the foregoing evidence,***

[19] *Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc.,* Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

> ***the Department finds that there is greater certainty that the DCF results understate the Company's cost of equity***.[20]

E. Conclusion

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF CURRENT MARKET CONDITIONS ON THE COST OF EQUITY FOR THE COMPANY?

A. Investors expect long-term interest rates to remain relatively high through 2024 in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields already are greater than utility stock dividend yields (*i.e.*, at levels that are not sustainable over the long-term), the share prices of utilities are likely to continue to decline, which is the reason a number of equity analysts have classified the sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

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[20] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 22-22, Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, November 30, 2022, p. 385-386; emphasis added.

VI. PROXY GROUP SELECTION

Q. WHY HAVE YOU USED A GROUP OF PROXY COMPANIES TO ESTIMATE THE COST OF EQUITY FOR OTP?

A. One of the purposes of this proceeding is to estimate the cost of equity for an electric company that is not itself publicly traded. Because the cost of equity is a market-based concept and because OTP's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and generally comparable to OTP in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process. As discussed below, however, OTP has risk factors that differentiates it from the companies in my proxy group.

Further, even if OTP were 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 companies included in the proxy group all possess a set of operating and risk characteristics that are generally comparable to OTP's, and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for OTP.

Q. PLEASE PROVIDE A BRIEF PROFILE OF OTP.

A. OTP is a vertically integrated electric distribution company that is a wholly-owned subsidiary of Otter Tail Corporation. OTP provides electric service to more than 133,000 customers in North Dakota, South Dakota and Minnesota (40.1 percent of which are located in North Dakota).[21] OTP had operating revenues of $550 million in 2022.[22] OTP owns generation facilities, including coal, natural gas, wind, and solar generation facilities. OTP has an investment grade long-term

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[21] Otter Tail Corporation, 2022 SEC Form 10-K, at 5-6.

[22] *Id.*, at 29.

rating of BBB+ (Outlook: Stable) from S&P, a rating of A3 (Outlook: Stable) from Moody's Investor Services, and BBB+ (Outlook: Stable) from Fitch Ratings.[23]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the group of 36 companies that *Value Line* classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends that have not been reduced in the last three years, since companies that do not pay dividends cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- own regulated generation assets;
- derive at least 40.00 percent of generation from owned generation;
- derive at least 60.00 percent of the Company's operating income from regulated electric operations; and
- were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

I developed the screening criteria and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size against establishing a proxy group of companies that are comparable in business and financial risk to the Company.

[23] SNL Financial, August 24, 2023; Moody's Investor Services, October 3, 2022; and Fitch Ratings, September 23, 2023.

Q. DID YOU INCLUDE OTTR IN YOUR PROXY GROUP?

A. No. Consistent with my general practice of excluding the subject company, or its parent holding company, from the proxy group, I excluded OTTR from my proxy group for OTP.

Q. DID YOU EXCLUDE ANY OTHER COMPANIES FROM THE PROXY GROUP?

Yes. I excluded Hawaiian Electric Industries, Inc. (HE). Although, it is my general practice to exclude HE because its operations are concentrated in Hawaii and, therefore, faces geographic concentration risk for both its regulated and substantial unregulated operations not applicable to the other utilities considered[24], HE also should be excluded in this case due to the uncertainty the company is facing following the recent wildfires in Hawaii. For example, the share price for HE declined 37 percent on August 14, 2023 due to investors' concerns regarding possible lawsuits and the resulting financial effect,[25] and on August 15, 2023, S&P subsequently downgraded the credit rating for HE from BBB- to BB-, which is below investment grade.[26] Therefore, the recent significant decline in HE's share price and the fact that the Company would no longer meet my credit rating screen provide additional support for my decision to exclude HE from my proxy group.

Q. WHAT IS THE COMPOSITION OF YOUR PROXY GROUP?

A. The proxy group consists of the following seventeen companies shown in Figure 7.

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24 Hawaii Electric Industries, Inc., 2022 Form 10-K, at 22.

25 Dattilo, Emily. "Hawaiian Electric Stock Sinks 37%. The Maui Wildfires Are Tied to the Drop." Barron's, August 14, 2023.

26 S&P Global Ratings, "Hawaiian Electric Industries Inc. And Subs. Downgraded To 'BB-'; Placed On CreditWatch Negative On Higher Wildfire Risk, August 15, 2023.

Figure 7: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. PLEASE BRIEFLY DISCUSS THE ROE IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. 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.

Q. HOW IS THE REQUIRED ROE DETERMINED?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required 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. 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.

Q. WHAT METHODS DID YOU USE TO ESTABLISH YOUR RECOMMENDED ROE IN THIS PROCEEDING?

A. I considered the results of the constant growth DCF model, the CAPM model, the ECAPM model, and the Bond Yield Plus Risk Premium methodology. As discussed in more detail below, a reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. IS IT IMPORTANT TO USE MORE THAN ONE ANALYTICAL APPROACH TO ESTIMATE THE COST OF EQUITY?

A. 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 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[27] suggest using the CAPM and

[27] Copeland, Tom, Tim Koller and Jack Murrin. Valuation: Measuring and Managing the Value of Companies. New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

Arbitrage Pricing Theory model, while Brigham and Gapenski[28] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. DO CURRENT MARKET CONDITIONS SUPPORT YOUR RELIANCE ON MORE THAN ONE ANALYTICAL APPROACH?

A. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. While the share prices of utilities have declined, the negative yield spread noted above is an indication that the share prices have not declined sufficiently to account for the recent rise in interest rates. As a result, equity analysts expect the utility sector to continue to underperform over the next year. Given the expected underperformance, it is reasonable to conclude that the DCF model is likely understating the forward-looking cost of equity because the model relies on historical share prices. The CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses offer some balance through the use of interest rates as a direct input into the models and therefore may better reflect the market conditions expected when the Company's rates are in effect. These recent changes in market conditions highlight the benefit of using multiple models since each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. It is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

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28 Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

B. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. 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:

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

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

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

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.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The constant growth DCF model requires the following four 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.

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR CONSTANT GROWTH DCF MODEL?

A. The dividend yield in my constant growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended July 31, 2023.

Q. WHY DID YOU USE 30-, 90-, AND 180-DAY AVERAGING PERIODS?

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. 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.

Q. WHY IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the constant growth DCF model.

Q. WHICH SOURCES OF LONG-TERM EARNINGS GROWTH RATES DID YOU USE?

A. My constant growth DCF model incorporates three sources of long-term earnings per share (EPS) growth rates: (1) Zacks Investment Research (Zacks); (2) Yahoo! Finance; and (3) Value Line.

Q. WHY ARE EPS GROWTH RATES THE APPROPRIATE GROWTH RATES TO BE RELIED ON IN THE DCF MODEL?

A. 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 reflect accurately investor perceptions of a company's growth prospects.

Q. HOW DID YOU CALCULATE THE RANGE OF RESULTS FOR THE CONSTANT GROWTH DCF MODELS?

A. I calculated a low-end result for the DCF models using the minimum growth rate of the three sources (i.e., the lowest of the Zacks, Yahoo Finance, and Value Line projected earnings growth rates) for each of the proxy group companies. I used 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 calculated results using the average growth rate from all three sources for each proxy group company.

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSES?

A. Figure 8 summarizes the results of my DCF analyses. As shown, the mean DCF results using the average growth rates range from 9.66 percent to 9.86 percent, and the mean results using the maximum growth rates range from 10.65 percent to

10.81 percent.[29] While I also summarize the mean DCF results using the minimum growth rates, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 8: Discounted Cash Flow Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.75%	9.86%	10.72%
90-Day Average	8.69%	9.80%	10.66%
180-Day Average	8.69%	9.80%	10.66%
Constant Growth Average	8.71%	9.82%	10.68%
	Median Low	Median	Median High
30-Day Average	9.11%	9.76%	10.65%
90-Day Average	9.01%	9.66%	10.80%
180-Day Average	9.01%	9.71%	10.81%
Constant Growth Average	9.04%	9.71%	10.76%

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE RESULTS OF THE DCF MODELS?

A. As discussed previously, one primary assumption of the DCF models is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF models with caution. Therefore, while I have given weight to the results of the DCF models, my recommendation also gives weight to the results of other cost of equity estimation models.

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29 *See* Exhibit___(AEB-1), Schedule 4.

C. CAPM Analysis

Q. PLEASE BRIEFLY DESCRIBE THE CAPM.

A. 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. 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.

The CAPM is defined by four components:

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

Where:

K_e = the required market ROE;

β = beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

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. Non-diversifiable risk is measured by Beta, which is defined as:

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

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) 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.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds of 3.92 percent;[30] (2) the average projected 30-year Treasury yield for the fourth quarter of 2023 through the fourth quarter of 2024, which is 3.90 percent;[31] and (3) the average projected 30-year Treasury bond yield for the period 2025 through 2029 of 3.80 percent.[32]

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. As shown on Exhibit___(AEB-1), Schedule 5, I used the beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The Value Line beta coefficients are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit___(AEB-1), 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 2022.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM IN THE CAPM?

A. I estimated the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit___(AEB-1), Schedule 7, the expected market return is calculated using

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30 Bloomberg Professional as of July 31, 2023.

31 *Blue Chip Financial Forecasts*, Vol. 42, No. 8, August 1, 2023, at 2.

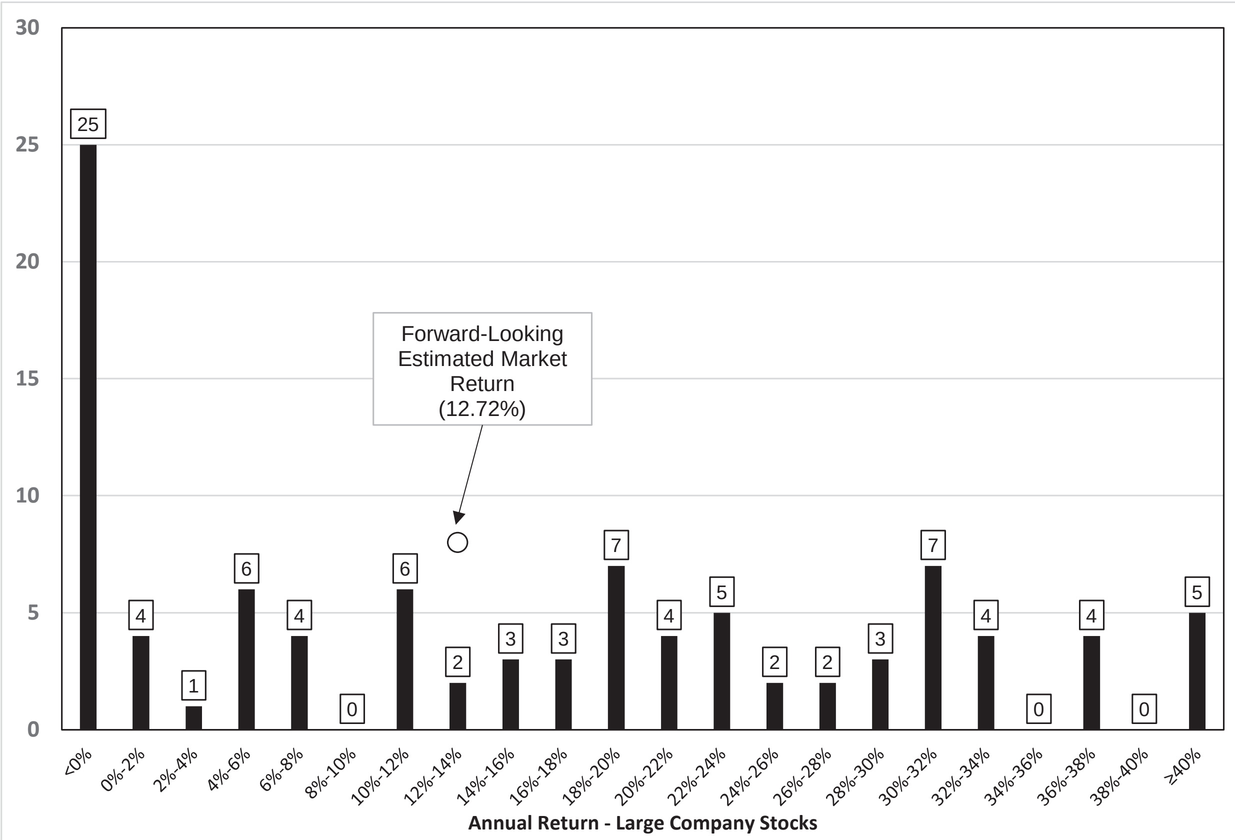
32 *Blue Chip Financial Forecasts*, Vol. 42, No. 6, June 1, 2023, at 14.

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 1.60 percent and a weighted long-term growth rate of 11.03 percent, the estimated required market return for the S&P 500 Index as of July 31, 2023 is 12.72 percent. Based on the three risk-free rates considered, the market risk premium ranges from 8.80 percent to 8.92 percent.

Q. HOW DOES THE CURRENT EXPECTED MARKET RETURN COMPARE TO OBSERVED HISTORICAL MARKET RETURNS?

A. As shown in Figure 9, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.72 percent is reasonable. In 50 out of the past 97 years (or roughly 52 percent of observations), the realized equity market return was 12.72 percent or greater.

Figure 9: Realized U.S. equity market returns (1926-2022) [33]



Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes, I did. I have also considered the results of an ECAPM in estimating the cost of equity for OTP.[34] The ECAPM calculates the product of the adjusted beta coefficient and the 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:

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

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[33] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

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

Where:

k_e = the required market ROE;

β = Adjusted beta coefficient of an individual security;

rf = the risk-free rate of return; and

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

In essence, 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, and that the CAPM underestimates the "alpha," or the constant return term.[35]

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.

Q. WHAT ARE THE RESULTS OF YOUR CAPM AND ECAPM ANALYSES?

A. As shown in Figure 10 (*see* also Exhibit___(AEB-1), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.46 percent to 11.66 percent, and the ECAPM analysis results range from 11.03 percent to 11.92 percent.

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35 *Id.* at 191.

Figure 10: CAPM and ECAPM Results

	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
CAPM			
Value Line Beta	11.66%	11.65%	11.64%
Bloomberg Beta	10.90%	10.89%	10.87%
Long-term Avg. Beta	10.49%	10.49%	10.46%
ECAPM			
Value Line Beta	11.92%	11.92%	11.91%
Bloomberg Beta	11.35%	11.35%	11.33%
Long-term Avg. Beta	11.05%	11.04%	11.03%

D. Bond Yield Plus Risk Premium Analysis

Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. 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 investors must be compensated to bear that 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 companies as the historical measure of the cost of equity to determine the risk premium.

Q. ARE THERE OTHER CONSIDERATIONS THAT SHOULD BE ADDRESSED IN CONDUCTING THIS ANALYSIS?

A. Yes. It is important to recognize both academic literature and market evidence indicating 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. Such an analysis can be developed based on a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs for electric utilities serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[36]

Q. IS THE BOND YIELD PLUS RISK PREMIUM ANALYSIS RELEVANT TO INVESTORS?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those authorizations as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q. WHAT DID YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS REVEAL?

A. As shown in Figure 11, from 1992 through July 2023, 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:

$$RP = a + b(T) \quad [6]$$

Where:

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

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[36] *See e.g.*, Berry, S. Keith. "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* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

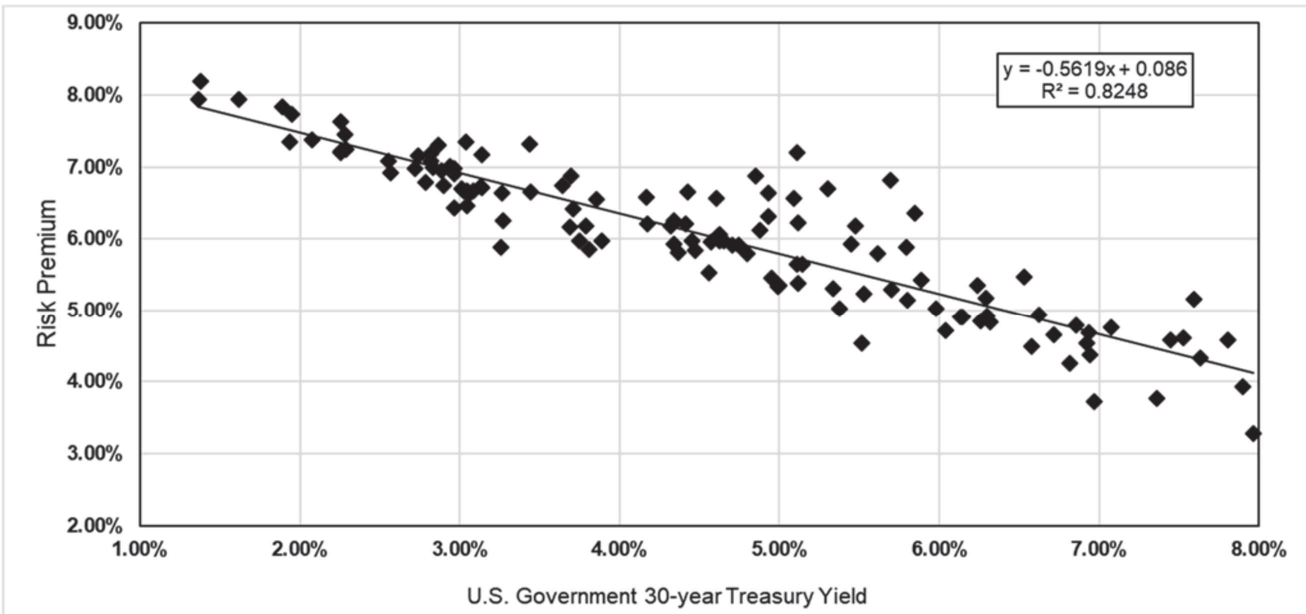
a = intercept term

b = slope term

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

Data regarding allowed ROEs were derived from all vertically integrated electric rate cases from 1992 through July 2023 as reported by Regulatory Research Associates (RRA).[37] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 11: Risk Premium Regression Analysis



As shown on Exhibit___(AEB-1), Schedule 8, based on the current 30-day average of the 30-year Treasury bond yield (*i.e.*, 3.92 percent), the risk premium would be 6.40 percent, resulting in an estimated cost of equity of 10.32 percent. Based on the consensus estimate of the near-term (*i.e.*, Q4/2023 – Q4/2024) projected 30-year Treasury bond yield (*i.e.*, 3.90 percent), the risk premium would be 6.41 percent, resulting in an estimated cost of equity of 10.31 percent. Based on a

[37] This analysis began with over 1,400 cases and 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. After applying those screening criteria, the analysis was based on data from over 700 cases.

consensus estimate of the longer-term (*i.e.*, 2025 – 2029) projection of the 30-year Treasury bond yield (*i.e.*, 3.80 percent), the risk premium would be 6.47 percent, resulting in an estimated cost of equity of 10.27 percent.

Q. HOW DID THE RESULTS OF THE BOND YIELD RISK PREMIUM INFORM YOUR RECOMMENDED ROE FOR OTP?

A. I have considered the results of the Bond Yield Risk Premium analysis in my recommended ROE for OTP. As noted, investors consider the authorized ROE of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VIII. REGULATORY AND BUSINESS RISK

Q. TAKEN ALONE, DO THE RESULTS FROM THE COST OF EQUITY ESTIMATION MODELS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE OF THE COST OF EQUITY FOR THE COMPANY?

A. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size

Q. DO SMALLER SIZE FIRMS, INCLUDING UTILITIES, FACE HIGHER RISKS?

A. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[38]

Q. HOW DOES THE SMALLER SIZE OF A UTILITY AFFECT ITS BUSINESS RISK?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, the destruction of demand as a result of general macroeconomic conditions, or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. HOW DO OTP'S ELECTRIC OPERATIONS IN NORTH DAKOTA COMPARE IN SIZE TO THE PROXY GROUP COMPANIES?

A. Comparing the market capitalization of OTTR and the implied market capitalization of OTP to the proxy group demonstrates that both the holding company and the electric service operations of OTP in North Dakota are substantially smaller than the median of the proxy group. Exhibit No.___(AEB-1), Schedule 9 provides the actual market capitalization for the proxy group companies and OTTR and estimates the implied market capitalization for OTP (i.e., the implied market capitalization if OTP's electric service operations in North

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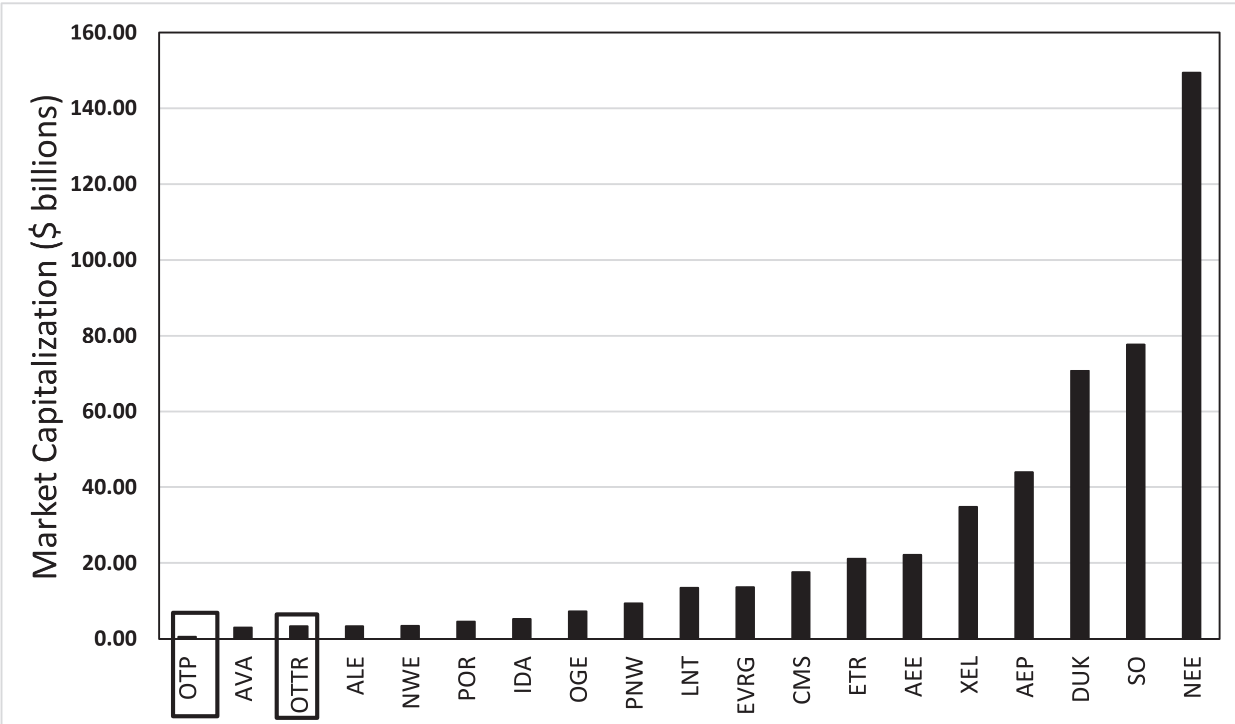
38 Annin, Michael. "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Dakota were a stand-alone publicly-traded entity).[39] Figure 12 below shows that the implied market capitalization for OTP is the lowest, and far below, any of the proxy group companies.

Figure 12: Market Capitalization of the Proxy Group Companies and OTTR[40]



Q. DID YOU ESTIMATE A SMALL SIZE RISK PREMIUM FOR OTP?

A. Yes. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[41] As shown in Exhibit No.____(AEB-1), Schedule 9, the median market capitalization of the proxy group is approximately $13.64 billion, which

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39 To estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculated the implied equity balance of OTP's capital structure by multiplying the Company's test year rate base by the Company's proposed common equity ratio of 53.50 percent. I then applied the median market-to-book ratio for the proxy group of 1.66 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $586.65 million, or approximately 4.30 percent of the median market capitalization for the proxy group.

40 Exhibit___(AEB-1), Schedule 9.

41 *Kroll* Cost of Capital Navigator – Size Premium; annual data as of December 31, 2022.

corresponds to the second decile of *Kroll's* market capitalization data.[42] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.45 percent (*i.e.*, 45 basis points). In comparison, OTP's implied market capitalization of approximately 586.65 million falls within the eighth decile, which corresponds to a size premium of 1.18 percent (*i.e.*, 118 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 73 basis points (*i.e.*, 118 percent minus 0.45 percent).

Q. WERE UTILITY COMPANIES INCLUDED IN *KROLL'S* SMALL SIZE RISK PREMIUM STUDY?

A. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that *Kroll* has included utility companies in its size risk premium study.[43]

Q. IS THE SIZE PREMIUM APPLICABLE TO COMPANIES IN REGULATED INDUSTRIES?

A. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[44] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed,

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42 *Id.*

43 Kroll. Valuation Handbook: Guide to Cost of Capital. 2019, Exhibit 7.2.

44 Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." The Quarterly Review of Economics and Finance, Vol. 43, No. 3, 2003, at 578–582.

the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[45]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[46] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[47]

Q. HAVE REGULATORS IN OTHER JURISDICTIONS MADE A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY RESULTS BASED ON A COMPANY'S SMALL SIZE?

A. Yes. In Order No. 15, the Regulatory Commission of Alaska (RCA) concluded that Alaska Electric Light and Power Company (AEL&P) was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[48] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model

45 *Id.*

46 Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011.

47 *Id.*

48 Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

presented in the case.[49] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[50] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[51]

Additionally, the Minnesota Public Utilities Commission (Minnesota PUC) authorized an ROE for OTP above the mean DCF results as a result of multiple factors, including OTP's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[52]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission (FERC) adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment

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[49] *Id.*, at 32 and 37.

[50] Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

[51] *Id.*

[52] Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[53]

Q. HOW HAVE YOU CONSIDERED THE SMALLER SIZE OF OTP IN YOUR RECOMMENDATION OF THE COMPANY'S ROE IN THIS PROCEEDING?

A. While I have estimated the effect of the Company's small size on the cost of equity, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of the Company's electric operations in North Dakota in the determination of where, within the range of analytical results, the Company's required cost of equity falls. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. Trading Volumes

Q. WHAT IS TRADING VOLUME AND WHAT EFFECT DOES A COMPANY'S TRADING VOLUME HAVE ON A LARGE INVESTOR'S ABILITY TO SELL A STAKE IN THE COMPANY?

A. Trading volume in this case refers to the number of publicly traded shares of a company. Institutional investors[54] often hold a large volume of shares in each investment. A smaller company (such as OTTR) often has a lower number of shares outstanding and fewer shares traded than larger firms. Institutional ownership of stock in a smaller company may limit the investor's ability to sell its shares without affecting the market price of the company, which presents a liquidity risk. Thus,

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[53] *Ass'n. of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022, at 20).

[54] Institutional ownership refers to the degree to which a company's common stock is held by large financial institutions, endowments, insurance companies, and mutual funds.

investors in companies with lower trading volume typically require a higher expected return as compensation for the liquidity risk.[55]

Q. HOW DO OTTER TAIL CORPORATION'S DAILY TRADING VOLUMES COMPARE TO OTHER UTILITIES IN THE PROXY GROUP?

A. The daily trading volumes of OTTR are far below those of the proxy group, as shown below in Figure 13. OTTR ranges between 7-10 percent that of total share volumes traded for the proxy group, or between 53-78 percent by volume as a proportion of outstanding shares, over a number of periods. Further, while OTTR was added to the S&P SmallCap 600 Index on February 23, 2023 (announced on February 16, 2023)[56], for the 30-day and 90-day averages (i.e., representative of the time period after OTTR was added to the S&P SmallCap 600 Index), OTTR is approximately 9 percent that of total share volumes traded for the proxy group, or between 66-74 percent by volume as a proportion of outstanding shares. As a result, despite the addition to the S&P SmallCap 600, OTTR's daily trading volumes are still far below those of the proxy group.

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55 Liquidity risk is defined as a financial risk associated with the inability to trade a financial asset quickly enough in the market without adversely impacting the asset's market price. An illiquid asset is one held long term, such as a home, while a liquid asset is one that can be quickly traded without a significant value loss, such as marketable securities.

56 S&P Global, "UFP Industries Set to Join S&P MidCap 400; Otter Tail to Join S&P SmallCap 600," February 16, 2023.

Figure 13: Trading Volume Analysis[57]

Average Since	OTTR/Proxy Group	
	By Volume	By Volume As % of Shares Outs.
30-Day Avg.	9%	66%
90-day Avg.	9%	74%
180-day Avg.	9%	74%
2023 YTD	10%	78%
Jan 2022 - Present	9%	70%
Jan 2021 - Present	8%	62%
Jan 2020 - Present	7%	58%
Jan 2019 - Present	7%	53%

Q. WHAT IS YOUR CONCLUSION REGARDING THE TRADING VOLUME ANALYSIS?

A. OTTR has very low trading volume relative to the proxy group. As a result, the trading volume disparity between OTTR and the proxy group indicate illiquidity with regard to OTTR shares, underscoring a higher cost of equity for OTTR and its subsidiary OTP.

C. Institutional Ownership

Q. WHAT IS "INSTITUTIONAL OWNERSHIP" AND HOW DOES IT RELATE TO COMMON EQUITY?

A. Institutional ownership refers to the degree to which a company's common stock is held by large financial institutions, endowments, insurance companies, and mutual funds. This differs from "retail ownership," which refers to common stock ownership by individual investors. Institutional investors typically have more resources and access to in-depth research than do retail owners, and thus, often take larger positions in a company's stock. Companies benefit from institutional

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57 Source: S&P Capital IQ Pro. See also Exhibit___(AEB-1), Schedule 10. Daily Average Volumes for OTTR excludes 2/17/2023 through 2/23/2023. The addition of OTTR to the S&P SmallCap 600 caused a brief significant increase trading volumes for OTTR between 2/17/2023 and 2/23/2023 that is not representative of the normal trading volume for OTTR.

investors as an important source of additional demand for a company's equity and as an efficient source of equity capital. Companies with lower levels of institutional ownership are at a disadvantage, lacking access to efficient capital.

Q. HOW DOES OTTR COMPARE TO THE PROXY GROUP IN TERMS OF INSTITUTIONAL OWNERSHIP?

A. As shown on Exhibit___(AEB-1), Schedule 11, as of September 14, 2023, approximately 60.74 percent of OTTR's common equity stock is held by institutional investors, compared to 81.71 percent for the proxy group average. OTTR's institutional ownership is also lower than every company included in the proxy group.

D. Customer Concentration

Q. PLEASE SUMMARIZE OTP'S CUSTOMER CONCENTRATION RISK.

A. OTP serves approximately 59,000 customers in North Dakota, all in the eastern portion of the State. As shown below in Figure 14, 48.89 percent of OTP's electric sales were derived from industrial load. Based on 2022 data, OTP's combined industrial and commercial sales are the second highest of the companies in the proxy group.[58]

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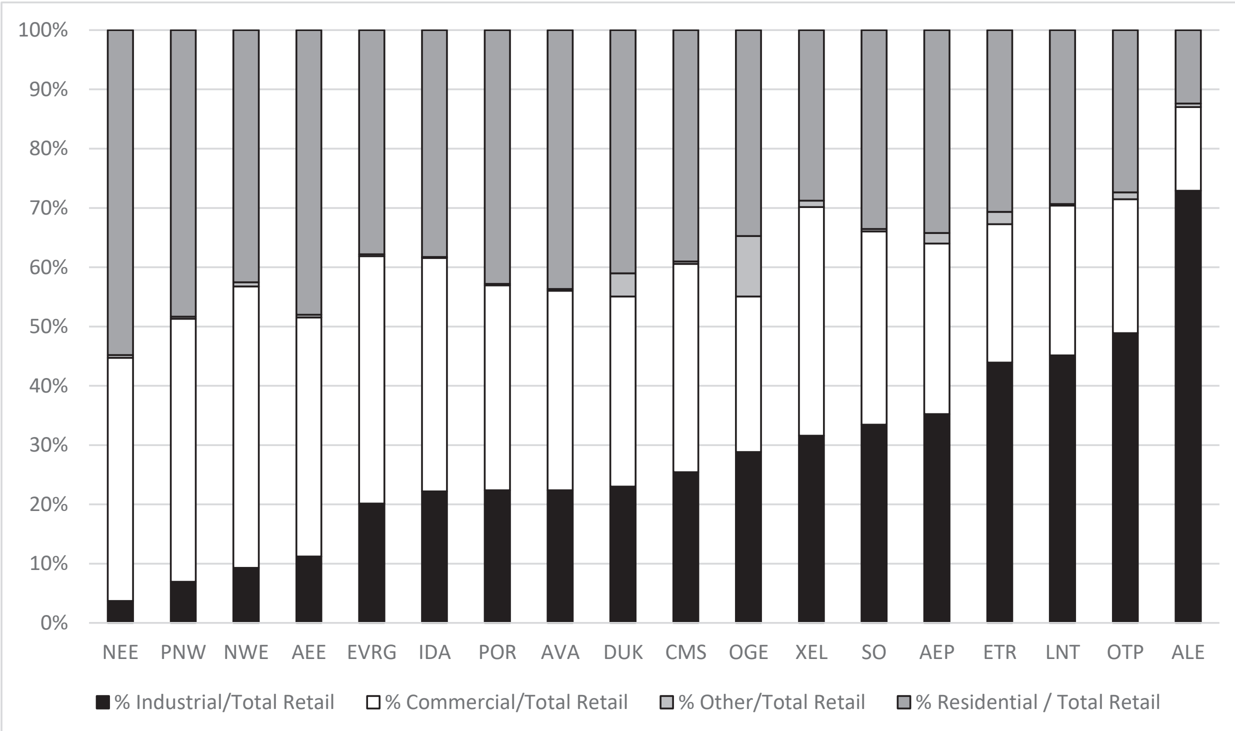
[58] Does not include "other" commercial or residential customers.

Figure 14: Customer Concentration – 2022 Sales[59]



Q. HOW DOES CUSTOMER CONCENTRATION AND THE COMPANY'S SERVICE TERRITORY AFFECT BUSINESS RISK?

A. 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 in their article, *Customer Concentration Risk and the Cost of Equity Capital,* 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.

[59] Source: S&P Global Market Intelligence (FERC Form 1) and Otter Tail Power Company, 2023 Annual Report, North Dakota Public Service Commission Case No. PU-23-249, June 27, 2023 at 7. Other sales includes: Total Public Street and Highway Lighting, Other Sales to Public Authorities, Sales to Railroad and Railways, and Interdepartmental Sales.

> Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock 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).[60]

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 Dhaliwal, Judd, Serfling and Shaik detail in the article, the increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[61]

Q. DO YOU EXPECT OTP'S CUSTOMER CONCENTRATION TO INCREASE?

A. Yes. The portion of OTP's sales derived from industrial and large commercial customers is likely to exceed 2022 levels. As explained by Company witness Ms. Amber M. Stalboerger, OTP began serving a large data processing customer in 2022, with the customer only operating at full capacity starting in late August of 2022. In fact, OTP is projecting to derive approximately 56 percent of total sales from industrial and large commercial customers for the 2024 Test Year, with the data processing customer accounting for approximately **[PROTECTED DATA BEGINS... ... PROTECTED DATA ENDS]** percent of total 2024 Test Year sales.

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60 Dhaliwal, Dan S., J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh. "Customer Concentration Risk and the Cost of Equity Capital." SSRN Electronic Journal (2016): 1-2. Web.

61 *Id.,* at 4.

Q. WHAT ASPECTS OF CUSTOMER CONCENTRATION SHOULD BE CONSIDERED IN THE ASSESSMENT OF OTP'S BUSINESS RISK RELATIVE TO THE COMPANIES IN THE PROXY GROUP?

A. There are two: (1) a disproportionately large, single customer; and (2) industry concentration.

Q. DOES OTP RELY ON A SINGLE LARGE CUSTOMER FOR A SIGNIFICANT PORTION OF SALES IN NORTH DAKOTA?

Yes. OTP is unique in that unlike most electric and natural gas utilities, the Company is dependent on a single customer for a large portion of its electric sales in North Dakota. And that customer has some unique attributes. For example, its operations are highly energy intensive - electricity comprises approximately 5 percent of a typical large customer's variable costs; for the data processing customer electricity comprises more than 15 times that proportion of variable costs.[62] The customer therefore is very sensitive to changes in power costs. Given the relatively low capital investment associated with its business the customer could move to another location where power costs are lower or could install onsite generation. In fact, in its 2022 Form 10-K, the customer noted vertically integrated power assets were a part of its growth strategy.[63]

The customer also provides services to customers in the cryptomining business,[64] a relatively new and extremely volatile industry.[65] The customer has identified its significant concentration of cryptomining customers as a risk factor to its business.[66] These two factors ((1) the customer's extremely high energy

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62 NDPSC Case No. 21-366, Application of Otter Tail Power Company for Confirmation of Compliance with and Approval of Electric Service Request under Otter Tail Power Company Rate Schedule 10.06 at 1 (Aug. 9, 2021).

63 Applied Digital Corporation, 2022 Form 10-K, *a*t 7.

64 Applied Digital Corporation, 2022 Form 10-K, at 5.

65 Powell, Tyler. "Utility Companies Face Credit Risk from Bankruptcies of Crypto Miners", February 24, 2023.

66 Applied Digital Corporation, 2022 Form 10-K, at 13.

dependence and sensitivity to energy prices; and (2) underlying volatility to the economic prospects of its customers) increase the risk OTP could see a sudden and significant decrease in load.

Q. ARE OTP'S REMAINING COMMERCIAL AND INDUSTRIAL CUSTOMERS CONCENTRATED IN CERTAIN INDUSTRIES?

A. Yes. A large portion of OTP's electric sales were to industrial customers that operate in the agricultural industry. Moreover, since the economy within and around OTP's service territories are reliant on the agricultural industry, OTP's commercial and residential customers also rely on the industry for sales and employment. For example, agricultural production in North Dakota accounts for 24.2 percent of the state GDP and 20.6 percent of state labor income, a majority of which is concentrated in crop production, processing, and handling.[67] Therefore, fluctuations in the business cycle, commodity prices, and ongoing trade disputes between the U.S. and China could adversely impact economic conditions in OTP's service territory. This could result in a reduction in sales to industrial customers. Further, if agricultural customers reduce output due to weak economic conditions, the effect would be compounded by a decline in local employment, which would also reduce electric sales to OTP's residential and commercial customers.

Q. HOW WOULD OTP'S PROPOSED SALES RIDER AFFECT THE COMPANY'S CUSTOMER CONCENTRATION RISK?

A. As explained by Company witness Ms. Amber M. Stalboerger, OTP's proposed sales rider would mitigate the risk associated with volatility in industrial and large commercial customer sales by either recovering or crediting the difference between the revenue requirement approved in this proceeding for the 2024 test year (i.e.,

[67] North Dakota Agriculture Industry, Economic Contribution Analysis, *NDSU Agribusiness and Applied Economics Report No. 816-S*, December 2022.

2024 Sales Rider Baseline Jurisdictional Cost of Service Study (JCOSS))[68] and the actual revenue requirement for each subsequent year (*i.e.*, Comparison JCOSS). The Comparison JCOSS would be developed by adjusting the 2024 Sales Rider Baseline JCOSS to reflect changes in actual sales, jurisdictional allocation factors, and base revenue from the calendar year. Variances would then be either credited or collected from customers in the subsequent year. In essence, the sales rider would allow the Company to account for the level of base revenues approved by the Commission in this proceeding by recovering(crediting) all variances under(over) that level from(to) customers.

Q. HOW WOULD THE PROPOSED SALES RIDER ADDRESS THE COMPANY'S CUSTOMER CONCENTRATION RISK AS COMPARED TO THE PROXY GROUP?

A. OTP's proposed sales rider would reduce the impact of customer concentration risk of the Company by recovering(crediting) variances between 2024 test year revenue and actual revenue from(to) customers. As shown in Exhibit___(AEB-1), Schedule 13 and discussed in more detail below, approximately 60 percent of the operating companies held by the proxy group have some form of non-volumetric rate design through either revenue decoupling, formula rates or straight fixed-variable rate design which mitigate the customer concentration and electric sales variability risk. Since the proxy group companies have already implemented similar risk mitigation measures for loads that are typically less concentrated than OTP's, OTP would not have less risk than the benchmark group if the Company's proposed sales rider was approved. Conversely, to the extent that OTP is not granted its proposed sales rider in this rate case, the Company's risk would be substantially elevated, relative to the proxy group.

68 The 2024 Sales Rider Baseline JCOSS excludes 2024 tear year riders costs and revenues.

Q. WHAT IS YOUR CONCLUSION REGARDING OTP'S CUSTOMER CONCENTRATION RISK AND ITS EFFECT ON THE COST OF EQUITY?

A. OTP is heavily reliant on sales to industrial and large commercial customers. As noted above, in 2022, 48.89 percent of OTP's electric sales by volume were to industrial customers. This concentration is higher than all of the proxy group companies, except one, and expected to increase in 2024. In addition, a large share of OTP's electric retail sales are to one customer. A high degree of customer concentration increases OTP's risk related to competition from alternative energy sources and economic conditions. Increased customer diversity decreases the effect that any one customer can have on a company's sales. Therefore, the risk of eroding revenue resulting from customer concentration is higher for OTP than the proxy group companies on average.

OTP has proposed a sales rider to mitigate the risk posed by customer concentration. When considering the relative risk of the Company and the proxy group, it is important to recognize that most of the companies in the proxy group have some form of a mechanism to mitigate electric sales risk. Therefore, adopting a sales rider will result in volumetric risk for the Company that is similar to the volumetric risk faced by the proxy group companies.

Absent the implementation of the sales rider, OTP has significant risk related to its high concentration of sales in a small number of customers, which is greater than the risk faced by the proxy group companies on average, the majority of which have some form of non-volumetric rate design. If the Company's proposed sales rider were not approved, then the Company is at much higher overall risk than the proxy group companies, and I would recommend that the authorized ROE for OTP be placed at the very high-end of my recommended ROE range.

E. Capital Expenditures

Q. PLEASE SUMMARIZE THE COMPANY'S CAPITAL EXPENDITURE REQUIREMENTS.

A. As of December 31, 2022, OTP had net utility plant in Minnesota, North Dakota and South Dakota of approximately $2.098 billion, and the Company currently projects capital expenditures for 2024 through 2027 of approximately $888 million.[69] Therefore, the Company's projected capital expenditures represent approximately 42.33 percent of its net utility plant as of December 31, 2022.

Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY ITS SUBSTANTIAL CAPITAL EXPENDITURE REQUIREMENTS?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. DO CREDIT RATING AGENCIES RECOGNIZE THE RISKS ASSOCIATED WITH ELEVATED LEVELS OF CAPITAL EXPENDITURES?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were

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[69] Otter Tail Corporation Second Quarter Earnings Conference Call Presentation at 36 (Aug. 1, 2023).

> extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[70]

Therefore, to the extent that OTP's rates do not permit the opportunity to recover its full cost of doing business, OTP will face increased recovery risk and thus increased pressure on its credit metrics.

Q. HOW DO OTP'S CAPITAL EXPENDITURE REQUIREMENTS COMPARE TO THOSE OF THE PROXY GROUP COMPANIES?

A. As shown in Exhibit___(AEB-1), Schedule 12, I calculated the ratio of expected capital expenditures to net utility plant for OTP and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024-2027 by its total net utility plant as of December 31, 2022. As shown therein OTP's ratio of capital expenditures as a percentage of net utility plant is in line with the median for the proxy group.

Q. DOES OTP HAVE THE ABILITY TO RECOVER CERTAIN CAPITAL EXPENDITURES BETWEEN RATE CASES?

A. Yes. OTP has an opportunity to recover certain capital expenditures through its Generation Cost Recovery Rider (GCR), Transmission Cost Recovery Rider (TCR), Advanced Meter Distribution Technology Cost Recovery Rider (AMDT), Renewable Resource Rider (RRR), and Environmental Cost Recovery Rider (ECR). These tracking mechanisms allow for recovery of certain costs in between rate cases for costs related to new generation facilities, new transmission facilities, advanced metering and outage management infrastructure, investment in new renewable energy projects, and investment in environmental improvement projects.

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70 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Q. DOES THE AVAILABILITY OF THESE RIDERS JUSTIFY ADJUSTING THE ROE AUTHORIZED IN THIS CASE?

A. No. The cost of equity analysis is conducted using market data for a proxy group of comparable companies and necessarily considers the relative risk of the subject company and the proxy group in the final determination of the ROE. Accordingly, although OTP's use of the capital tracking mechanisms may reduce its own risk, the appropriate point of comparison is whether those tracking mechanisms are reducing risk relative to the proxy group, which I discuss below.

Q. HOW DOES THE EXISTENCE OF THESE TRACKERS COMPARE WITH THE CAPITAL INVESTMENT AND OTHER TRACKERS THAT HAVE BEEN IMPLEMENTED BY THE PROXY COMPANIES?

A. As shown in Exhibit___(AEB-1), Schedule 13, 56 out of 83 (or approximately 67 percent) of the operating companies held by the proxy group recover costs through capital tracking mechanisms. So, while OTP's capital tracking mechanisms are a positive aspect of North Dakota regulation, as shown in Exhibit___(AEB-1), Schedule 13, such clauses have become commonplace in utility regulation. As a result, OTP's capital tracking mechanisms do not reduce the Company's risk vis-à-vis that of the proxy group.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF OTP'S CAPITAL SPENDING REQUIREMENTS ON ITS RISK PROFILE AND COST OF CAPITAL?

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, similar to a number of the operating subsidiaries of the proxy group, OTP can recover some portion of the Company's projected capital expenditures through capital tracking mechanisms. Therefore, I conclude that, the Company's risk profile regarding capital expenditures is consistent with that of the proxy group.

F. Regulatory Risk

Q. PLEASE EXPLAIN HOW THE REGULATORY ENVIRONMENT AFFECTS INVESTORS' RISK ASSESSMENTS.

A. 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 a reasonable opportunity to recover the return of, and the market-required return on, 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.

Q. HOW DO CREDIT RATING AGENCIES CONSIDER REGULATORY RISK IN ESTABLISHING A COMPANY'S CREDIT RATING?

A. 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.[71]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[72] 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.[73]

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71 Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 4.

72 Standard & Poor's Global Ratings. Ratings Direct. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 2.

73 *Id.*

Q. HOW DOES THE REGULATORY ENVIRONMENT IN WHICH A UTILITY OPERATES AFFECT ITS ACCESS TO AND COST OF CAPITAL?

A. 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, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[74] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[75]

Q. HAVE YOU CONDUCTED ANY ANALYSIS OF THE REGULATORY FRAMEWORK IN NORTH DAKOTA RELATIVE TO THE JURISDICTIONS IN WHICH THE COMPANIES IN YOUR PROXY GROUP OPERATE?

A. Yes. I have evaluated the regulatory framework in North Dakota on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE. These are: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of revenue decoupling mechanisms or other clauses that provide revenue stabilization; and (3) the prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit___(AEB-1), Schedule 13 and are summarized below.

<u>Test Year Convention</u>: OTP is proposing a forecasted test year. As shown in Exhibit___(AEB-1), Schedule 13, approximately 45 percent of the utility

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74 Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 6.

75 *Id.*

operating subsidiaries of the companies in the proxy group also have partially or fully forecast test years.

Volumetric Risk: OTP does not currently have protection against volumetric risk through a revenue decoupling mechanism, formula-based rate, or a straight fixed-variable rate design. Although the Company is requesting a sales rider in this proceeding to mitigate the effect of volumetric risk, approximately 60 percent of the utility operating subsidiaries of the proxy group companies have some form of non-volumetric rate design that allow them to break the link between customer usage and revenues.

Capital Cost Recovery: OTP does have the opportunity to recover certain capital expenditures through capital tracking mechanisms. Similarly, approximately 67 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism in place.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PERCEIVED RISKS RELATED TO THE NORTH DAKOTA REGULATORY ENVIRONMENT?

A. As discussed throughout this section of my testimony, 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, similar to OTP, many of the companies in the proxy group have timely cost recovery through forecasted test years, cost recovery trackers and revenue stabilization mechanisms. As a result, I conclude, that if the Company's proposed sales rider were approved, OTP's regulatory risk would be similar to that of the proxy group.

Finally, while my analysis assumes that the Company's proposed sales rider will be approved, the volumetric risk of OTP would increase substantially if the Commission does not approve the Company's proposal. Thus, if the sales rider is not approved, then the authorized ROE for OTP should be placed at the very high-end of my recommended ROE range.

G. Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. 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.

Q. WHY IS IT IMPORTANT TO CONSIDER FLOTATION COSTS IN THE ALLOWED ROE?

A. 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.

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. 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 costs are incurred prior to the test year but remain 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 the Company the opportunity to earn its required rate of return in the future.

Q. PLEASE PROVIDE AN EXAMPLE OF WHY A FLOTATION COST ADJUSTMENT IS NECESSARY TO COMPENSATE INVESTORS FOR THE CAPITAL THEY HAVE INVESTED.

A. Suppose OTTR, the parent company of OTP, issues stock with a value of $100, and an equity investor invests $100 in OTTR in exchange for that stock. Further, suppose that, after paying flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, OTTR ends up with only $97 of net issuance proceeds rather than the $100 the investor contributed. OTTR 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.

Q. IS THE DATE OF OTTR'S LAST ISSUANCE OF COMMON EQUITY IMPORTANT IN THE DETERMINATION OF FLOTATION COSTS?

A. No. As shown in Exhibit___(AEB-1), Schedule 14, OTTR has closed on several equity issuances over the past several years, including an approximately $36 million at-the-market (ATM) issuance in 2020.[76] However, it is important to recognize flotation costs for all equity issuances since these costs reduce the permanent capital structure of the company. Therefore, the vintage of the issuance is not particularly important because an investor should have a reasonable opportunity to earn a return on the full amount of capital that she has contributed

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[76] Issuance information provided by OTP.

in every year of the investment. As noted in my earlier example, the investor contributed $100, but due to flotation costs, OTTR only ends up with $97 to invest in rate base. Without the recognition of flotation costs, the investor will only earn a return on the $97 invested in rate base in year 1 as well as every subsequent year of the investment. Therefore, adjusting the ROE in year 1 to recognize flotation costs will only award the opportunity for the investor earn a return on her full investment in year 1 and then in year 2 and after the investor will still only earn a return on the $97 invested in rate base. As a result, the ROE should be adjusted for flotation costs in every year regardless of the vintage of the issuance because as long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE OTP IS A WHOLLY OWNED SUBSIDIARY OF OTTR?

A. No, it is not. Although OTP is a wholly owned subsidiary of OTTR, it is appropriate to consider flotation costs. A wholly owned subsidiary receives equity capital from its parent and provides returns on the capital that rolls up to the parent, which is designated to attract and raise capital based upon the returns of its subsidiary, or subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund utility operations and inhibits the utility's ability to obtain new equity capital at a reasonable cost. This is particularly important for OTP because, as I previously discuss, it is planning significant capital expenditures over the next several years.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS RECOGNIZED BY THE ACADEMIC AND FINANCIAL COMMUNITIES?

A. Yes, it is. 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.[77]

Further, Dr. Myron Gordon recognized that the DCF model did not include the cost of floating a new stock issue and proposed a means for regulators to recognize these costs in his text on the subject.[78]

Q. WHAT IS THE EFFECT OF FLOTATION COSTS ON OTP'S COST OF EQUITY?

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by OTTR in each of the company's common equity issuances since 2004. As shown in Exhibit___(AEB-1), Schedule 14, based on the flotation costs of previous issuances, the impact on the proxy group's cost of equity amounts to 14 basis points (*i.e.*, 0.14 percent) based on the median and 14 basis points (*i.e.*, 0.14 percent) based on the mean.

Q. DO YOUR FINAL COST OF EQUITY MODEL RESULTS INCLUDE AN ADJUSTMENT FOR FLOTATION COST RECOVERY?

A. 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

77 Pratt, Shannon P. Cost of Capital Estimation and Applications. Second Edition, at 220-21.

78 Gordon, Myron, "The Cost of Capital to a Public Utility", 1974, pp. 164-166.

recommendations regarding the range of reasonable ROEs and ultimate recommended ROE.

IX. CAPITAL STRUCTURE

Q. IS THE CAPITAL STRUCTURE OF THE COMPANY AN IMPORTANT CONSIDERATION IN THE DETERMINATION OF THE APPROPRIATE ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as OTP. All else 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 the claim of debt holders. Therefore, the greater the debt service requirement, the less cash flow 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.

Q. WHAT IS OTP'S PROPOSED CAPITAL STRUCTURE?

A. The Company is proposing to establish a capital structure consisting of 53.50 percent common equity, 43.55 percent long-term debt, and 2.95 percent short-term debt.

Q. DID YOU CONDUCT ANY ANALYSIS TO DETERMINE IF THIS REQUESTED EQUITY RATIO WAS REASONABLE?

A. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the equity ratios for the Company.

Q. PLEASE DISCUSS YOUR ANALYSIS OF THE CAPITAL STRUCTURES OF THE PROXY GROUP COMPANIES.

A. I calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent eight quarters for each of the companies in the proxy group at the operating subsidiary level. As shown on Exhibit___(AEB-1), Schedule 15, the average common equity ratio for the operating subsidiaries of the proxy group companies was 52.06 percent (within a range from 45.30 percent to 60.41 percent). Given that OTP's proposed equity ratio of 53.50 percent is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, I consider its proposed equity ratio to be reasonable.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED IN SETTING THE COMPANY'S CAPITAL STRUCTURE?

A. 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, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality.[79]

Fitch Ratings (Fitch) also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost

79 Moody's Investors Service, Outlook. "Outlook turns stable on low prices and credit-supportive regulation." September 7, 2023.

pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that some counterbalances/offsets against these headwinds include "higher authorized ROEs and the use of tools such as securitization of under-recovered fuel balances."[80]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry resulting from inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[81]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the industry as a whole, and OTP in particular in the context of this proceeding.

Q. WHAT IS YOUR CONCLUSION REGARDING AN APPROPRIATE EQUITY RATIO FOR OTP?

A. Considering the actual capital structures of the utility operating subsidiaries of the proxy group, I believe that the Company's proposed common equity ratio of 53.50 percent is reasonable. The proposed equity ratio is well within the range of equity

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80 Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

81 S&P Global Ratings. "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

ratios established by the capital structures of the utility operating subsidiaries of the proxy companies.

X. CONCLUSION AND RECOMMENDATION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR OTP?

A. Figure 15 summarizes the results of my cost of equity analyses. Based on the quantitative and qualitative analyses presented in my direct testimony, and the business and financial risks of the Company as compared to the proxy group, an ROE of 10.60 percent reasonable.

Figure 15: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.75%	9.86%	10.72%
90-Day Average	8.69%	9.80%	10.66%
180-Day Average	8.69%	9.80%	10.66%
Constant Growth Average	8.71%	9.82%	10.68%
	Median Low	Median	Median High
30-Day Average	9.11%	9.76%	10.65%
90-Day Average	9.01%	9.66%	10.80%
180-Day Average	9.01%	9.71%	10.81%
Constant Growth Average	9.04%	9.71%	10.76%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.66%	11.65%	11.64%
Bloomberg Beta	10.90%	10.89%	10.87%
Long-term Avg. Beta	10.49%	10.49%	10.46%
ECAPM			
Value Line Beta	11.92%	11.92%	11.91%
Bloomberg Beta	11.35%	11.35%	11.33%
Long-term Avg. Beta	11.05%	11.04%	11.03%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.32%	10.31%	10.27%

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO OTP'S PROPOSED CAPITAL STRUCTURE?

A. My conclusion is that the Company's proposal to establish a capital structure consisting of 53.50 percent common equity, 43.55 percent long-term debt, and 2.95 percent short-term debt is reasonable when compared to actual capital structures of the proxy group companies. Further, taking into consideration the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, I conclude that the Company's proposal is reasonable and should be adopted for ratemaking purposes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Ann E. Bulkley

PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-______-______-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-_____	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-____	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

SUMMARY OF COE ANALYSES RESULTS

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.75%	9.86%	10.72%
90-Day Average	8.69%	9.80%	10.66%
180-Day Average	8.69%	9.80%	10.66%
Constant Growth Average	8.71%	9.82%	10.68%
	Median Low	Median	Median High
30-Day Average	9.11%	9.76%	10.65%
90-Day Average	9.01%	9.66%	10.80%
180-Day Average	9.01%	9.71%	10.81%
Constant Growth Average	9.04%	9.71%	10.76%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.66%	11.65%	11.64%
Bloomberg Beta	10.90%	10.89%	10.87%
Long-term Avg. Beta	10.49%	10.49%	10.46%
ECAPM			
Value Line Beta	11.92%	11.92%	11.91%
Bloomberg Beta	11.35%	11.35%	11.33%
Long-term Avg. Beta	11.05%	11.04%	11.03%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.32%	10.31%	10.27%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Company-Owned Generation > 40%	% Regulated Electric Operating Income > 60% of Total Operating Income	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB	Yes	Yes	Yes	43.27%	100.56%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	72.75%	87.90%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	75.34%	84.57%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.62%	97.34%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	59.47%	73.85%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	42.50%	65.48%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	Yes	81.53%	91.02%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	71.43%	98.21%	No
Evergy, Inc.	EVRG	Yes	A-	Yes	Yes	Yes	62.14%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	65.35%	99.91%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	96.40%	92.16%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	55.82%	84.28%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	50.65%	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	Yes	76.09%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	54.88%	100.00%	No
Southern Company	SO	Yes	BBB+	Yes	Yes	Yes	76.85%	75.31%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	57.97%	86.47%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: S&P Capital IQ Pro
[6] Source: S&P Capital IQ Pro
[7] Source: Form 10-K's for 2022, 2021, and 2020
[8] Source: Form 10-K's for 2022, 2021, and 2020
[9] Source: 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 EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.71	$58.12	4.66%	4.84%	6.00%	8.10%	8.10%	7.40%	10.80%	12.24%	12.95%
Alliant Energy Corporation	LNT	$1.81	$53.11	3.41%	3.52%	6.50%	7.00%	6.50%	6.67%	10.02%	10.19%	10.53%
Ameren Corporation	AEE	$2.52	$84.17	2.99%	3.09%	6.50%	5.90%	6.40%	6.27%	8.98%	9.35%	9.59%
American Electric Power Company, Inc.	AEP	$3.32	$85.37	3.89%	4.00%	6.00%	5.20%	5.60%	5.60%	9.19%	9.60%	10.01%
Avista Corporation	AVA	$1.84	$38.97	4.72%	4.87%	6.50%	6.30%	6.30%	6.37%	11.17%	11.24%	11.37%
CMS Energy Corporation	CMS	$1.95	$59.91	3.25%	3.37%	6.50%	7.80%	7.80%	7.37%	9.86%	10.74%	11.18%
Duke Energy Corporation	DUK	$4.02	$91.84	4.38%	4.50%	5.00%	5.74%	6.10%	5.61%	9.49%	10.11%	10.61%
Entergy Corporation	ETR	$4.28	$99.98	4.28%	4.37%	0.50%	6.60%	5.70%	4.27%	4.79%	8.64%	11.02%
Evergy, Inc.	EVRG	$2.45	$59.41	4.12%	4.23%	7.50%	2.67%	5.20%	5.12%	6.85%	9.35%	11.78%
IDACORP, Inc.	IDA	$3.16	$102.78	3.07%	3.14%	5.00%	3.70%	3.70%	4.13%	6.83%	7.27%	8.15%
NextEra Energy, Inc.	NEE	$1.87	$73.81	2.53%	2.65%	9.50%	8.80%	8.40%	8.90%	11.04%	11.55%	12.15%
NorthWestern Corporation	NWE	$2.56	$57.12	4.48%	4.58%	3.50%	4.50%	5.20%	4.40%	8.06%	8.98%	9.80%
OGE Energy Corporation	OGE	$1.66	$35.97	4.60%	4.72%	6.50%	negative	3.70%	5.10%	8.39%	9.82%	11.25%
Pinnacle West Capital Corporation	PNW	$3.46	$81.98	4.22%	4.33%	2.50%	6.10%	6.30%	4.97%	6.77%	9.29%	10.65%
Portland General Electric Company	POR	$1.90	$47.35	4.01%	4.13%	5.00%	5.90%	6.00%	5.63%	9.11%	9.76%	10.13%
Southern Company	SO	$2.80	$71.21	3.93%	4.05%	6.50%	7.30%	4.00%	5.93%	8.01%	9.98%	11.38%
Xcel Energy Inc.	XEL	$2.08	$63.31	3.29%	3.39%	6.00%	6.15%	6.30%	6.15%	9.38%	9.54%	9.69%
Mean				3.87%	3.99%	5.62%	6.11%	5.96%	5.88%	8.75%	9.86%	10.72%
Median				4.01%	4.13%	6.00%	6.13%	6.10%	5.63%	9.11%	9.76%	10.65%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([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 EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.71	$60.73	4.46%	4.63%	6.00%	8.10%	8.10%	7.40%	10.60%	12.03%	12.74%
Alliant Energy Corporation	LNT	$1.81	$52.96	3.42%	3.53%	6.50%	7.00%	6.50%	6.67%	10.03%	10.20%	10.54%
Ameren Corporation	AEE	$2.52	$85.01	2.96%	3.06%	6.50%	5.90%	6.40%	6.27%	8.95%	9.32%	9.56%
American Electric Power Company, Inc.	AEP	$3.32	$87.56	3.79%	3.90%	6.00%	5.20%	5.60%	5.60%	9.09%	9.50%	9.91%
Avista Corporation	AVA	$1.84	$41.27	4.46%	4.60%	6.50%	6.30%	6.30%	6.37%	10.90%	10.97%	11.10%
CMS Energy Corporation	CMS	$1.95	$59.78	3.26%	3.38%	6.50%	7.80%	7.80%	7.37%	9.87%	10.75%	11.19%
Duke Energy Corporation	DUK	$4.02	$93.61	4.29%	4.41%	5.00%	5.74%	6.10%	5.61%	9.40%	10.03%	10.53%
Entergy Corporation	ETR	$4.28	$102.70	4.17%	4.26%	0.50%	6.60%	5.70%	4.27%	4.68%	8.52%	10.90%
Evergy, Inc.	EVRG	$2.45	$59.91	4.09%	4.19%	7.50%	2.67%	5.20%	5.12%	6.81%	9.32%	11.74%
IDACORP, Inc.	IDA	$3.16	$105.42	3.00%	3.06%	5.00%	3.70%	3.70%	4.13%	6.75%	7.19%	8.07%
NextEra Energy, Inc.	NEE	$1.87	$74.95	2.49%	2.61%	9.50%	8.80%	8.40%	8.90%	11.00%	11.51%	12.11%
NorthWestern Corporation	NWE	$2.56	$57.50	4.45%	4.55%	3.50%	4.50%	5.20%	4.40%	8.03%	8.95%	9.77%
OGE Energy Corporation	OGE	$1.66	$36.24	4.57%	4.69%	6.50%	negative	3.70%	5.10%	8.36%	9.79%	11.22%
Pinnacle West Capital Corporation	PNW	$3.46	$79.25	4.37%	4.47%	2.50%	6.10%	6.30%	4.97%	6.92%	9.44%	10.80%
Portland General Electric Company	POR	$1.90	$48.51	3.92%	4.03%	5.00%	5.90%	6.00%	5.63%	9.01%	9.66%	10.03%
Southern Company	SO	$2.80	$71.08	3.94%	4.06%	6.50%	7.30%	4.00%	5.93%	8.02%	9.99%	11.38%
Xcel Energy Inc.	XEL	$2.08	$65.62	3.17%	3.27%	6.00%	6.15%	6.30%	6.15%	9.26%	9.42%	9.57%
Mean				3.81%	3.92%	5.62%	6.11%	5.96%	5.88%	8.69%	9.80%	10.66%
Median				3.94%	4.06%	6.00%	6.13%	6.10%	5.63%	9.01%	9.66%	10.80%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([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 EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.71	$61.40	4.41%	4.58%	6.00%	8.10%	8.10%	7.40%	10.55%	11.98%	12.69%
Alliant Energy Corporation	LNT	$1.81	$52.94	3.42%	3.53%	6.50%	7.00%	6.50%	6.67%	10.03%	10.20%	10.54%
Ameren Corporation	AEE	$2.52	$85.04	2.96%	3.06%	6.50%	5.90%	6.40%	6.27%	8.95%	9.32%	9.56%
American Electric Power Company, Inc.	AEP	$3.32	$89.50	3.71%	3.81%	6.00%	5.20%	5.60%	5.60%	9.01%	9.41%	9.82%
Avista Corporation	AVA	$1.84	$40.91	4.50%	4.64%	6.50%	6.30%	6.30%	6.37%	10.94%	11.01%	11.14%
CMS Energy Corporation	CMS	$1.95	$59.98	3.25%	3.37%	6.50%	7.80%	7.80%	7.37%	9.86%	10.74%	11.18%
Duke Energy Corporation	DUK	$4.02	$95.66	4.20%	4.32%	5.00%	5.74%	6.10%	5.61%	9.31%	9.93%	10.43%
Entergy Corporation	ETR	$4.28	$105.06	4.07%	4.16%	0.50%	6.60%	5.70%	4.27%	4.58%	8.43%	10.81%
Evergy, Inc.	EVRG	$2.45	$59.79	4.10%	4.20%	7.50%	2.67%	5.20%	5.12%	6.82%	9.33%	11.75%
IDACORP, Inc.	IDA	$3.16	$104.49	3.02%	3.09%	5.00%	3.70%	3.70%	4.13%	6.78%	7.22%	8.10%
NextEra Energy, Inc.	NEE	$1.87	$76.95	2.43%	2.54%	9.50%	8.80%	8.40%	8.90%	10.93%	11.44%	12.05%
NorthWestern Corporation	NWE	$2.56	$56.61	4.52%	4.62%	3.50%	4.50%	5.20%	4.40%	8.10%	9.02%	9.84%
OGE Energy Corporation	OGE	$1.66	$36.85	4.49%	4.61%	6.50%	negative	3.70%	5.10%	8.28%	9.71%	11.14%
Pinnacle West Capital Corporation	PNW	$3.46	$76.38	4.53%	4.64%	2.50%	6.10%	6.30%	4.97%	7.09%	9.61%	10.97%
Portland General Electric Company	POR	$1.90	$47.66	3.99%	4.10%	5.00%	5.90%	6.00%	5.63%	9.09%	9.73%	10.11%
Southern Company	SO	$2.80	$68.72	4.07%	4.20%	6.50%	7.30%	4.00%	5.93%	8.16%	10.13%	11.52%
Xcel Energy Inc.	XEL	$2.08	$66.41	3.13%	3.23%	6.00%	6.15%	6.30%	6.15%	9.23%	9.38%	9.53%
Mean				3.81%	3.92%	5.62%	6.11%	5.96%	5.88%	8.69%	9.80%	10.66%
Median				4.07%	4.16%	6.00%	6.13%	6.10%	5.63%	9.01%	9.71%	10.81%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
Alliant Energy Corporation	LNT	3.92%	0.85	12.72%	8.80%	11.40%	11.73%
Ameren Corporation	AEE	3.92%	0.85	12.72%	8.80%	11.40%	11.73%
American Electric Power Company, Inc.	AEP	3.92%	0.75	12.72%	8.80%	10.52%	11.07%
Avista Corporation	AVA	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
CMS Energy Corporation	CMS	3.92%	0.80	12.72%	8.80%	10.96%	11.40%
Duke Energy Corporation	DUK	3.92%	0.85	12.72%	8.80%	11.40%	11.73%
Entergy Corporation	ETR	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
Evergy, Inc.	EVRG	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
IDACORP, Inc.	IDA	3.92%	0.80	12.72%	8.80%	10.96%	11.40%
NextEra Energy, Inc.	NEE	3.92%	0.95	12.72%	8.80%	12.28%	12.39%
NorthWestern Corporation	NWE	3.92%	0.95	12.72%	8.80%	12.28%	12.39%
OGE Energy Corporation	OGE	3.92%	1.00	12.72%	8.80%	12.72%	12.72%
Pinnacle West Capital Corporation	PNW	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
Portland General Electric Company	POR	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
Southern Company	SO	3.92%	0.90	12.72%	8.80%	11.84%	12.06%
Xcel Energy Inc.	XEL	3.92%	0.85	12.72%	8.80%	11.40%	11.73%
Mean						11.66%	11.92%
Median						11.84%	12.06%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2023
[2] Source: Value Line
[3] Source: Market Return
[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 & VL BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
Alliant Energy Corporation	LNT	3.90%	0.85	12.72%	8.82%	11.40%	11.73%
Ameren Corporation	AEE	3.90%	0.85	12.72%	8.82%	11.40%	11.73%
American Electric Power Company, Inc.	AEP	3.90%	0.75	12.72%	8.82%	10.51%	11.06%
Avista Corporation	AVA	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
CMS Energy Corporation	CMS	3.90%	0.80	12.72%	8.82%	10.95%	11.40%
Duke Energy Corporation	DUK	3.90%	0.85	12.72%	8.82%	11.40%	11.73%
Entergy Corporation	ETR	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
Evergy, Inc.	EVRG	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
IDACORP, Inc.	IDA	3.90%	0.80	12.72%	8.82%	10.95%	11.40%
NextEra Energy, Inc.	NEE	3.90%	0.95	12.72%	8.82%	12.28%	12.39%
NorthWestern Corporation	NWE	3.90%	0.95	12.72%	8.82%	12.28%	12.39%
OGE Energy Corporation	OGE	3.90%	1.00	12.72%	8.82%	12.72%	12.72%
Pinnacle West Capital Corporation	PNW	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
Portland General Electric Company	POR	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
Southern Company	SO	3.90%	0.90	12.72%	8.82%	11.84%	12.06%
Xcel Energy Inc.	XEL	3.90%	0.85	12.72%	8.82%	11.40%	11.73%
Mean						11.65%	11.92%
Median						11.84%	12.06%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 8, August 1, 2023, at 2
[2] Source: Value Line
[3] Source: Market Return
[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 & VL BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2025 - 2029)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
Alliant Energy Corporation	LNT	3.80%	0.85	12.72%	8.92%	11.38%	11.71%
Ameren Corporation	AEE	3.80%	0.85	12.72%	8.92%	11.38%	11.71%
American Electric Power Company, Inc.	AEP	3.80%	0.75	12.72%	8.92%	10.49%	11.05%
Avista Corporation	AVA	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
CMS Energy Corporation	CMS	3.80%	0.80	12.72%	8.92%	10.93%	11.38%
Duke Energy Corporation	DUK	3.80%	0.85	12.72%	8.92%	11.38%	11.71%
Entergy Corporation	ETR	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
Evergy, Inc.	EVRG	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
IDACORP, Inc.	IDA	3.80%	0.80	12.72%	8.92%	10.93%	11.38%
NextEra Energy, Inc.	NEE	3.80%	0.95	12.72%	8.92%	12.27%	12.38%
NorthWestern Corporation	NWE	3.80%	0.95	12.72%	8.92%	12.27%	12.38%
OGE Energy Corporation	OGE	3.80%	1.00	12.72%	8.92%	12.72%	12.72%
Pinnacle West Capital Corporation	PNW	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
Portland General Electric Company	POR	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
Southern Company	SO	3.80%	0.90	12.72%	8.92%	11.83%	12.05%
Xcel Energy Inc.	XEL	3.80%	0.85	12.72%	8.92%	11.38%	11.71%
Mean						11.64%	11.91%
Median						11.83%	12.05%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[2] Source: Value Line
[3] Source: Market Return
[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 & BLOOMBERG BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.92%	0.82	12.72%	8.80%	11.17%	11.56%
Alliant Energy Corporation	LNT	3.92%	0.79	12.72%	8.80%	10.87%	11.33%
Ameren Corporation	AEE	3.92%	0.75	12.72%	8.80%	10.52%	11.07%
American Electric Power Company, Inc.	AEP	3.92%	0.76	12.72%	8.80%	10.58%	11.12%
Avista Corporation	AVA	3.92%	0.75	12.72%	8.80%	10.50%	11.05%
CMS Energy Corporation	CMS	3.92%	0.75	12.72%	8.80%	10.51%	11.06%
Duke Energy Corporation	DUK	3.92%	0.72	12.72%	8.80%	10.25%	10.87%
Entergy Corporation	ETR	3.92%	0.85	12.72%	8.80%	11.44%	11.76%
Evergy, Inc.	EVRG	3.92%	0.78	12.72%	8.80%	10.78%	11.26%
IDACORP, Inc.	IDA	3.92%	0.79	12.72%	8.80%	10.90%	11.35%
NextEra Energy, Inc.	NEE	3.92%	0.81	12.72%	8.80%	11.08%	11.49%
NorthWestern Corporation	NWE	3.92%	0.86	12.72%	8.80%	11.46%	11.77%
OGE Energy Corporation	OGE	3.92%	0.92	12.72%	8.80%	12.04%	12.21%
Pinnacle West Capital Corporation	PNW	3.92%	0.83	12.72%	8.80%	11.19%	11.57%
Portland General Electric Company	POR	3.92%	0.78	12.72%	8.80%	10.79%	11.27%
Southern Company	SO	3.92%	0.77	12.72%	8.80%	10.72%	11.22%
Xcel Energy Inc.	XEL	3.92%	0.74	12.72%	8.80%	10.43%	11.00%
Mean						10.90%	11.35%
Median						10.79%	11.27%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2023
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[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 & BLOOMBERG BETA

$K = Rf + \beta\ (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.82	12.72%	8.82%	11.17%	11.55%
Alliant Energy Corporation	LNT	3.90%	0.79	12.72%	8.82%	10.87%	11.33%
Ameren Corporation	AEE	3.90%	0.75	12.72%	8.82%	10.52%	11.07%
American Electric Power Company, Inc.	AEP	3.90%	0.76	12.72%	8.82%	10.58%	11.11%
Avista Corporation	AVA	3.90%	0.75	12.72%	8.82%	10.49%	11.05%
CMS Energy Corporation	CMS	3.90%	0.75	12.72%	8.82%	10.50%	11.06%
Duke Energy Corporation	DUK	3.90%	0.72	12.72%	8.82%	10.25%	10.86%
Entergy Corporation	ETR	3.90%	0.85	12.72%	8.82%	11.44%	11.76%
Evergy, Inc.	EVRG	3.90%	0.78	12.72%	8.82%	10.77%	11.26%
IDACORP, Inc.	IDA	3.90%	0.79	12.72%	8.82%	10.89%	11.35%
NextEra Energy, Inc.	NEE	3.90%	0.81	12.72%	8.82%	11.08%	11.49%
NorthWestern Corporation	NWE	3.90%	0.86	12.72%	8.82%	11.45%	11.77%
OGE Energy Corporation	OGE	3.90%	0.92	12.72%	8.82%	12.03%	12.20%
Pinnacle West Capital Corporation	PNW	3.90%	0.83	12.72%	8.82%	11.19%	11.57%
Portland General Electric Company	POR	3.90%	0.78	12.72%	8.82%	10.78%	11.27%
Southern Company	SO	3.90%	0.77	12.72%	8.82%	10.72%	11.22%
Xcel Energy Inc.	XEL	3.90%	0.74	12.72%	8.82%	10.42%	11.00%
Mean						10.89%	11.35%
Median						10.78%	11.27%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 8, August 1, 2023, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[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 & BLOOMBERG BETA

$K = Rf + \beta\ (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.82	12.72%	8.92%	11.15%	11.54%
Alliant Energy Corporation	LNT	3.80%	0.79	12.72%	8.92%	10.85%	11.31%
Ameren Corporation	AEE	3.80%	0.75	12.72%	8.92%	10.49%	11.05%
American Electric Power Company, Inc.	AEP	3.80%	0.76	12.72%	8.92%	10.55%	11.09%
Avista Corporation	AVA	3.80%	0.75	12.72%	8.92%	10.47%	11.03%
CMS Energy Corporation	CMS	3.80%	0.75	12.72%	8.92%	10.48%	11.04%
Duke Energy Corporation	DUK	3.80%	0.72	12.72%	8.92%	10.22%	10.84%
Entergy Corporation	ETR	3.80%	0.85	12.72%	8.92%	11.42%	11.75%
Evergy, Inc.	EVRG	3.80%	0.78	12.72%	8.92%	10.75%	11.24%
IDACORP, Inc.	IDA	3.80%	0.79	12.72%	8.92%	10.87%	11.33%
NextEra Energy, Inc.	NEE	3.80%	0.81	12.72%	8.92%	11.06%	11.47%
NorthWestern Corporation	NWE	3.80%	0.86	12.72%	8.92%	11.44%	11.76%
OGE Energy Corporation	OGE	3.80%	0.92	12.72%	8.92%	12.03%	12.20%
Pinnacle West Capital Corporation	PNW	3.80%	0.83	12.72%	8.92%	11.17%	11.56%
Portland General Electric Company	POR	3.80%	0.78	12.72%	8.92%	10.76%	11.25%
Southern Company	SO	3.80%	0.77	12.72%	8.92%	10.69%	11.20%
Xcel Energy Inc.	XEL	3.80%	0.74	12.72%	8.92%	10.40%	10.98%
Mean						10.87%	11.33%
Median						10.76%	11.25%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Market Return
[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 & VALUE LINE LT AVERAGE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[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)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.92%	0.79	12.72%	8.80%	10.83%	11.30%
Alliant Energy Corporation	LNT	3.92%	0.75	12.72%	8.80%	10.52%	11.07%
Ameren Corporation	AEE	3.92%	0.73	12.72%	8.80%	10.30%	10.90%
American Electric Power Company, Inc.	AEP	3.92%	0.68	12.72%	8.80%	9.86%	10.57%
Avista Corporation	AVA	3.92%	0.79	12.72%	8.80%	10.83%	11.30%
CMS Energy Corporation	CMS	3.92%	0.69	12.72%	8.80%	9.99%	10.67%
Duke Energy Corporation	DUK	3.92%	0.67	12.72%	8.80%	9.77%	10.51%
Entergy Corporation	ETR	3.92%	0.75	12.72%	8.80%	10.47%	11.04%
Evergy, Inc.	EVRG	3.92%	0.95	12.72%	8.80%	12.28%	12.39%
IDACORP, Inc.	IDA	3.92%	0.73	12.72%	8.80%	10.34%	10.94%
NextEra Energy, Inc.	NEE	3.92%	0.73	12.72%	8.80%	10.34%	10.94%
NorthWestern Corporation	NWE	3.92%	0.75	12.72%	8.80%	10.47%	11.04%
OGE Energy Corporation	OGE	3.92%	0.93	12.72%	8.80%	12.10%	12.26%
Pinnacle West Capital Corporation	PNW	3.92%	0.74	12.72%	8.80%	10.39%	10.97%
Portland General Electric Company	POR	3.92%	0.75	12.72%	8.80%	10.52%	11.07%
Southern Company	SO	3.92%	0.66	12.72%	8.80%	9.68%	10.44%
Xcel Energy Inc.	XEL	3.92%	0.66	12.72%	8.80%	9.68%	10.44%
Mean						10.49%	11.05%
Median						10.39%	10.97%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2023
[2] Source: LT Beta
[3] Source: Market Return
[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 & VALUE LINE LT AVERAGE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.79	12.72%	8.82%	10.82%	11.30%
Alliant Energy Corporation	LNT	3.90%	0.75	12.72%	8.82%	10.51%	11.06%
Ameren Corporation	AEE	3.90%	0.73	12.72%	8.82%	10.29%	10.90%
American Electric Power Company, Inc.	AEP	3.90%	0.68	12.72%	8.82%	9.85%	10.57%
Avista Corporation	AVA	3.90%	0.79	12.72%	8.82%	10.82%	11.30%
CMS Energy Corporation	CMS	3.90%	0.69	12.72%	8.82%	9.98%	10.67%
Duke Energy Corporation	DUK	3.90%	0.67	12.72%	8.82%	9.76%	10.50%
Entergy Corporation	ETR	3.90%	0.75	12.72%	8.82%	10.47%	11.03%
Evergy, Inc.	EVRG	3.90%	0.95	12.72%	8.82%	12.28%	12.39%
IDACORP, Inc.	IDA	3.90%	0.73	12.72%	8.82%	10.34%	10.93%
NextEra Energy, Inc.	NEE	3.90%	0.73	12.72%	8.82%	10.34%	10.93%
NorthWestern Corporation	NWE	3.90%	0.75	12.72%	8.82%	10.47%	11.03%
OGE Energy Corporation	OGE	3.90%	0.93	12.72%	8.82%	12.10%	12.25%
Pinnacle West Capital Corporation	PNW	3.90%	0.74	12.72%	8.82%	10.38%	10.97%
Portland General Electric Company	POR	3.90%	0.75	12.72%	8.82%	10.51%	11.06%
Southern Company	SO	3.90%	0.66	12.72%	8.82%	9.68%	10.44%
Xcel Energy Inc.	XEL	3.90%	0.66	12.72%	8.82%	9.68%	10.44%
Mean						10.49%	11.04%
Median						10.38%	10.97%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 8, August 1, 2023, at 2
[2] Source: LT Beta
[3] Source: Market Return
[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 & VALUE LINE LT AVERAGE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.80%	0.79	12.72%	8.92%	10.80%	11.28%
Alliant Energy Corporation	LNT	3.80%	0.75	12.72%	8.92%	10.49%	11.05%
Ameren Corporation	AEE	3.80%	0.73	12.72%	8.92%	10.27%	10.88%
American Electric Power Company, Inc.	AEP	3.80%	0.68	12.72%	8.92%	9.82%	10.54%
Avista Corporation	AVA	3.80%	0.79	12.72%	8.92%	10.80%	11.28%
CMS Energy Corporation	CMS	3.80%	0.69	12.72%	8.92%	9.95%	10.64%
Duke Energy Corporation	DUK	3.80%	0.67	12.72%	8.92%	9.73%	10.48%
Entergy Corporation	ETR	3.80%	0.75	12.72%	8.92%	10.44%	11.01%
Evergy, Inc.	EVRG	3.80%	0.95	12.72%	8.92%	12.27%	12.38%
IDACORP, Inc.	IDA	3.80%	0.73	12.72%	8.92%	10.31%	10.91%
NextEra Energy, Inc.	NEE	3.80%	0.73	12.72%	8.92%	10.31%	10.91%
NorthWestern Corporation	NWE	3.80%	0.75	12.72%	8.92%	10.44%	11.01%
OGE Energy Corporation	OGE	3.80%	0.93	12.72%	8.92%	12.09%	12.25%
Pinnacle West Capital Corporation	PNW	3.80%	0.74	12.72%	8.92%	10.35%	10.95%
Portland General Electric Company	POR	3.80%	0.75	12.72%	8.92%	10.49%	11.05%
Southern Company	SO	3.80%	0.66	12.72%	8.92%	9.64%	10.41%
Xcel Energy Inc.	XEL	3.80%	0.66	12.72%	8.92%	9.64%	10.41%
Mean						10.46%	11.03%
Median						10.35%	10.95%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA - 2013 - 2022

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	Average
ALLETE, Inc.	ALE	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.90	0.79
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.75
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.73
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	0.68
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.79
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.69
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.67
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.75
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.95
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.73
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	0.73
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.75
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	0.93
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	0.74
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.75
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.66
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.66
Mean		0.72	0.73	0.75	0.68	0.69	0.58	0.57	0.89	0.89	0.87	0.75

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] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimated Weighted Average Dividend Yield	1.60%
[2] Estimated Weighted Average Long-Term Growth Rate	11.03%
[3] S&P 500 Estimated Required Market Return	12.72%

		[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 Growth Rate	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	325.27	98.86	32,157	0.11%	5.06%	0.01%	13.50%	0.01%
American Express Co	AXP	736.46	168.88	124,373	0.42%	1.42%	0.01%	11.89%	0.05%
Verizon Communications Inc	VZ	4,204.04	34.08	143,274		7.66%			
Broadcom Inc	AVGO	412.69	898.65	370,859	1.26%	2.05%	0.03%	12.79%	0.16%
Boeing Co/The	BA	603.20	238.85	144,075					
Caterpillar Inc	CAT	515.36	265.17	136,657	0.47%	1.96%	0.01%	15.00%	0.07%
JPMorgan Chase & Co	JPM	2,922.29	157.96	461,605		2.53%		0.00%	
Chevron Corp	CVX	1,853.00	163.66	303,262	1.03%	3.69%	0.04%	8.77%	0.09%
Coca-Cola Co/The	KO	4,324.35	61.93	267,807	0.91%	2.97%	0.03%	7.19%	0.07%
AbbVie Inc	ABBV	1,764.29	149.58	263,902	0.90%	3.96%	0.04%	2.48%	0.02%
Walt Disney Co/The	DIS	1,827.31	88.89	162,429				22.77%	
FleetCor Technologies Inc	FLT	73.83	248.91	18,378	0.06%			12.18%	0.01%
Extra Space Storage Inc	EXR	211.21	139.57	29,478	0.10%	2.89%	0.00%	3.96%	0.00%
Exxon Mobil Corp	XOM	4,003.00	107.24	429,282	1.46%	3.39%	0.05%	13.89%	0.20%
Phillips 66	PSX	460.91	111.55	51,415	0.18%	3.77%	0.01%	9.46%	0.02%
General Electric Co	GE	1,088.38	114.24	124,336	0.42%	0.28%	0.00%	7.00%	0.03%
HP Inc	HPQ	985.96	32.83	32,369		3.20%		-4.44%	
Home Depot Inc/The	HD	1,005.38	333.84	335,635	1.14%	2.50%	0.03%	0.56%	0.01%
Monolithic Power Systems Inc	MPWR	47.42	559.49	26,533		0.71%			
International Business Machines Corp	IBM	911.01	144.18	131,349	0.45%	4.61%	0.02%	3.35%	0.01%
Johnson & Johnson	JNJ	2,598.97	167.53	435,405	1.48%	2.84%	0.04%	4.54%	0.07%
McDonald's Corp	MCD	730.09	293.20	214,064	0.73%	2.07%	0.02%	9.60%	0.07%
Merck & Co Inc	MRK	2,537.44	106.65	270,618		2.74%		27.61%	
3M Co	MMM	551.99	111.50	61,547	0.21%	5.38%	0.01%	10.00%	0.02%
American Water Works Co Inc	AWK	194.67	147.43	28,700	0.10%	1.92%	0.00%	7.95%	0.01%
Bank of America Corp	BAC	7,946.37	32.00	254,284		3.00%		-4.00%	
Pfizer Inc	PFE	5,645.31	36.06	203,570		4.55%		-1.00%	
Procter & Gamble Co/The	PG	2,362.10	156.30	369,196	1.26%	2.41%	0.03%	5.69%	0.07%
AT&T Inc	T	7,149.00	14.52	103,803	0.35%	7.64%	0.03%	2.44%	0.01%
Travelers Cos Inc/The	TRV	228.94	172.61	39,518	0.13%	2.32%	0.00%	14.92%	0.02%
RTX Corp	RTX	1,455.52	87.93	127,983	0.44%	2.68%	0.01%	8.88%	0.04%
Analog Devices Inc	ADI	501.42	199.53	100,048	0.34%	1.72%	0.01%	7.50%	0.03%
Walmart Inc	WMT	2,692.84	159.86	430,477	1.47%	1.43%	0.02%	8.00%	0.12%
Cisco Systems Inc	CSCO	4,075.06	52.04	212,066	0.72%	3.00%	0.02%	7.50%	0.05%
Intel Corp	INTC	4,188.00	35.77	149,805	0.51%	1.40%	0.01%	5.65%	0.03%
General Motors Co	GM	1,375.91	38.37	52,793	0.18%	0.94%	0.00%	0.36%	0.00%
Microsoft Corp	MSFT	7,429.76	335.92	2,495,806	8.50%	0.81%	0.07%	16.62%	1.41%
Dollar General Corp	DG	219.34	168.86	37,038	0.13%	1.40%	0.00%	3.36%	0.00%
Cigna Group/The	CI	295.87	295.10	87,312	0.30%	1.67%	0.00%	10.80%	0.03%
Kinder Morgan Inc	KMI	2,228.17	17.71	39,461	0.13%	6.38%	0.01%	2.00%	0.00%
Citigroup Inc	C	1,936.70	47.66	92,303		4.45%		-7.06%	
American International Group Inc	AIG	723.75	60.28	43,628	0.15%	2.39%	0.00%	9.50%	0.01%
Altria Group Inc	MO	1,785.04	45.42	81,077	0.28%	8.28%	0.02%	6.00%	0.02%
HCA Healthcare Inc	HCA	275.19	272.81	75,075	0.26%	0.88%	0.00%	7.58%	0.02%
International Paper Co	IP	346.00	36.06	12,477		5.13%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1,291.52	17.38	22,447	0.08%	2.76%	0.00%	3.72%	0.00%
Abbott Laboratories	ABT	1,738.95	111.33	193,597	0.66%	1.83%	0.01%	2.18%	0.01%
Aflac Inc	AFL	604.23	72.34	43,710	0.15%	2.32%	0.00%	4.66%	0.01%
Air Products and Chemicals Inc	APD	222.12	305.33	67,821	0.23%	2.29%	0.01%	10.26%	0.02%
Royal Caribbean Cruises Ltd	RCL	256.17	109.11	27,951				124.32%	
Hess Corp	HES	307.05	151.73	46,589		1.15%		-23.46%	
Archer-Daniels-Midland Co	ADM	536.10	84.96	45,547		2.12%		-6.10%	
Automatic Data Processing Inc	ADP	412.10	247.26	101,896	0.35%	2.02%	0.01%	16.00%	0.06%
Verisk Analytics Inc	VRSK	144.79	228.94	33,148	0.11%	0.59%	0.00%	11.71%	0.01%
AutoZone Inc	AZO	18.16	2,481.72	45,058	0.15%			13.48%	0.02%
Avery Dennison Corp	AVY	80.73	184.01	14,855	0.05%	1.76%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.36	151.83	20,703				23.17%	
MSCI Inc	MSCI	79.09	548.08	43,347	0.15%	1.01%	0.00%	14.63%	0.02%
Ball Corp	BALL	314.55	58.69	18,461	0.06%	1.36%	0.00%	9.50%	0.01%
Axon Enterprise Inc	AXON	73.89	185.93	13,737	0.05%			15.10%	0.01%
Ceridian HCM Holding Inc	CDAY	155.03	70.81	10,978					
Carrier Global Corp	CARR	837.63	59.55	49,881	0.17%	1.24%	0.00%	10.65%	0.02%
Bank of New York Mellon Corp/The	BK	778.78	45.36	35,326	0.12%	3.70%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	411.75	90.96	37,452	0.13%	1.50%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	506.41	45.23	22,905	0.08%	2.56%	0.00%	0.83%	0.00%
Becton Dickinson & Co	BDX	284.02	278.62	79,132	0.27%	1.31%	0.00%	9.60%	0.03%
Berkshire Hathaway Inc	BRK/B	1,295.97	351.96	456,130					
Best Buy Co Inc	BBY	218.21	83.05	18,122	0.06%	4.43%	0.00%	3.14%	0.00%
Boston Scientific Corp	BSX	1,437.70	51.85	74,545	0.25%			12.10%	0.03%
Bristol-Myers Squibb Co	BMY	2,089.10	62.19	129,921	0.44%	3.67%	0.02%	2.55%	0.01%
Brown-Forman Corp	BF/B	310.11	70.60	21,894	0.07%	1.16%	0.00%	8.55%	0.01%
Coterra Energy Inc	CTRA	757.45	27.54	20,860		2.90%		25.02%	
Campbell Soup Co	CPB	298.09	45.82	13,659	0.05%	3.23%	0.00%	3.39%	0.00%
Hilton Worldwide Holdings Inc	HLT	261.51	155.49	40,663	0.14%	0.39%	0.00%	17.14%	0.02%
Carnival Corp	CCL	1,116.01	18.84	21,026					
Qorvo Inc	QRVO	98.74	110.02	10,863				-12.00%	
UDR Inc	UDR	329.48	40.88	13,469	0.05%	4.11%	0.00%	8.23%	0.00%
Clorox Co/The	CLX	123.62	151.48	18,727	0.06%	3.17%	0.00%	17.02%	0.01%
Paycom Software Inc	PAYC	60.29	368.76	22,234		0.41%			
CMS Energy Corp	CMS	291.73	60.58	17,672	0.06%	3.22%	0.00%	7.90%	0.00%
Newell Brands Inc	NWL	414.20	11.16	4,622		2.51%		-4.00%	

		[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 Growth Rate	Cap-Weighted Long-Term Growth Est.
Colgate-Palmolive Co	CL	826.69	76.26	63,044	0.21%	2.52%	0.01%	6.93%	0.01%
EPAM Systems Inc	EPAM	57.91	236.81	13,713	0.05%			4.39%	0.00%
Comerica Inc	CMA	131.78	53.96	7,111		5.26%		-6.12%	
Conagra Brands Inc	CAG	477.06	32.81	15,652	0.05%	4.27%	0.00%	1.31%	0.00%
Consolidated Edison Inc	ED	346.54	94.86	32,873	0.11%	3.42%	0.00%	4.00%	0.00%
Corning Inc	GLW	852.98	33.94	28,950	0.10%	3.30%	0.00%	6.58%	0.01%
Cummins Inc	CMI	141.56	260.80	36,919		2.58%			
Caesars Entertainment Inc	CZR	215.20	59.02	12,701					
Danaher Corp	DHR	738.35	255.06	188,324	0.64%	0.42%	0.00%	9.00%	0.06%
Target Corp	TGT	461.56	136.47	62,989	0.21%	3.22%	0.01%	8.91%	0.02%
Deere & Co	DE	293.19	429.60	125,955	0.43%	1.16%	0.00%	17.28%	0.07%
Dominion Energy Inc	D	835.94	53.55	44,765	0.15%	4.99%	0.01%	2.21%	0.00%
Dover Corp	DOV	139.87	145.97	20,417	0.07%	1.38%	0.00%	13.00%	0.01%
Alliant Energy Corp	LNT	251.39	53.74	13,510	0.05%	3.37%	0.00%	6.48%	0.00%
Steel Dynamics Inc	STLD	169.03	106.58	18,016		1.60%			
Duke Energy Corp	DUK	771.00	93.62	72,181	0.25%	4.38%	0.01%	6.12%	0.02%
Regency Centers Corp	REG	171.00	65.53	11,205	0.04%	3.97%	0.00%	3.57%	0.00%
Eaton Corp PLC	ETN	398.60	205.32	81,841	0.28%	1.68%	0.00%	15.00%	0.04%
Ecolab Inc	ECL	284.72	183.14	52,144	0.18%	1.16%	0.00%	14.00%	0.02%
Revvity Inc	RVTY	125.44	122.95	15,423		0.23%		-6.17%	
Emerson Electric Co	EMR	571.50	91.35	52,207	0.18%	2.28%	0.00%	10.31%	0.02%
EOG Resources Inc	EOG	584.86	132.53	77,511	0.26%	2.49%	0.01%	10.83%	0.03%
Aon PLC	AON	202.87	318.50	64,613	0.22%	0.77%	0.00%	10.09%	0.02%
Entergy Corp	ETR	211.45	102.70	21,716	0.07%	4.17%	0.00%	6.33%	0.00%
Equifax Inc	EFX	122.72	204.08	25,045	0.09%	0.76%	0.00%	11.40%	0.01%
EQT Corp	EQT	361.66	42.18	15,255		1.42%		29.19%	
IQVIA Holdings Inc	IQV	185.55	223.76	41,518	0.14%			9.04%	0.01%
Gartner Inc	IT	79.04	353.59	27,948	0.10%			7.53%	0.01%
FedEx Corp	FDX	251.19	269.95	67,808	0.23%	1.87%	0.00%	13.00%	0.03%
FMC Corp	FMC	125.04	96.23	12,033	0.04%	2.41%	0.00%	3.50%	0.00%
Brown & Brown Inc	BRO	283.61	70.45	19,981	0.07%	0.65%	0.00%	9.00%	0.01%
Ford Motor Co	F	3,931.37	13.21	51,933	0.18%	4.54%	0.01%	10.96%	0.02%
NextEra Energy Inc	NEE	2,023.71	73.30	148,338	0.51%	2.55%	0.01%	8.48%	0.04%
Franklin Resources Inc	BEN	498.98	29.24	14,590		4.10%		-5.90%	
Garmin Ltd	GRMN	191.29	105.89	20,256	0.07%	2.76%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1,433.29	44.65	63,996		1.34%		-13.66%	
Dexcom Inc	DXCM	387.87	124.56	48,313				30.96%	
General Dynamics Corp	GD	273.04	223.58	61,047	0.21%	2.36%	0.00%	10.90%	0.02%
General Mills Inc	GIS	585.18	74.74	43,737	0.15%	3.16%	0.00%	8.00%	0.01%
Genuine Parts Co	GPC	140.44	155.72	21,869	0.07%	2.44%	0.00%	8.95%	0.01%
Atmos Energy Corp	ATO	144.49	121.71	17,586	0.06%	2.43%	0.00%	7.96%	0.00%
WW Grainger Inc	GWW	50.00	738.49	36,925		1.01%			
Halliburton Co	HAL	898.55	39.08	35,115		1.64%		23.40%	
L3Harris Technologies Inc	LHX	189.13	189.49	35,839	0.12%	2.41%	0.00%	2.29%	0.00%
Healthpeak Properties Inc	PEAK	547.05	21.83	11,942	0.04%	5.50%	0.00%	4.72%	0.00%
Insulet Corp	PODD	69.70	276.75	19,288				35.05%	
Catalent Inc	CTLT	180.27	48.52	8,747				-6.33%	
Fortive Corp	FTV	352.02	78.35	27,581	0.09%	0.36%	0.00%	7.93%	0.01%
Hershey Co/The	HSY	149.85	231.31	34,663	0.12%	2.06%	0.00%	9.50%	0.01%
Synchrony Financial	SYF	418.18	34.54	14,444		2.90%		64.00%	
Hormel Foods Corp	HRL	546.27	40.88	22,331	0.08%	2.69%	0.00%	2.50%	0.00%
Arthur J Gallagher & Co	AJG	215.50	214.80	46,289	0.16%	1.02%	0.00%	13.20%	0.02%
Mondelez International Inc	MDLZ	1,360.42	74.13	100,848	0.34%	2.29%	0.01%	8.89%	0.03%
CenterPoint Energy Inc	CNP	629.43	30.09	18,940	0.06%	2.53%	0.00%	8.02%	0.01%
Humana Inc	HUM	124.95	456.83	57,079	0.19%	0.77%	0.00%	13.82%	0.03%
Willis Towers Watson PLC	WTW	104.82	211.33	22,152	0.08%	1.59%	0.00%	10.82%	0.01%
Illinois Tool Works Inc	ITW	303.90	263.32	80,024	0.27%	1.99%	0.01%	3.75%	0.01%
CDW Corp/DE	CDW	134.79	187.07	25,215	0.09%	1.26%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	228.05	199.44	45,483	0.15%	1.50%	0.00%	10.10%	0.02%
Interpublic Group of Cos Inc/The	IPG	384.94	34.23	13,176	0.04%	3.62%	0.00%	6.99%	0.00%
International Flavors & Fragrances Inc	IFF	255.09	84.61	21,583		3.83%		21.71%	
Generac Holdings Inc	GNRC	62.19	153.70	9,559	0.03%			8.00%	0.00%
NXP Semiconductors NV	NXPI	257.80	222.98	57,485		1.82%		20.50%	
Kellogg Co	K	342.76	66.89	22,927	0.08%	3.59%	0.00%	2.40%	0.00%
Broadridge Financial Solutions Inc	BR	117.98	167.92	19,811		1.73%			
Kimberly-Clark Corp	KMB	338.19	129.10	43,660	0.15%	3.66%	0.01%	9.71%	0.01%
Kimco Realty Corp	KIM	619.89	20.26	12,559	0.04%	4.54%	0.00%	4.65%	0.00%
Oracle Corp	ORCL	2,714.26	117.23	318,193	1.08%	1.36%	0.01%	15.00%	0.16%
Kroger Co/The	KR	717.75	48.64	34,911	0.12%	2.38%	0.00%	4.76%	0.01%
Lennar Corp	LEN	252.53	126.83	32,028		1.18%		-3.15%	
Eli Lilly & Co	LLY	949.27	454.55	431,492		0.99%		21.73%	
Bath & Body Works Inc	BBWI	228.91	37.06	8,483	0.03%	2.16%	0.00%	11.46%	0.00%
Charter Communications Inc	CHTR	149.67	405.19	60,645	0.21%			15.90%	0.03%
Lincoln National Corp	LNC	169.56	28.04	4,754		6.42%			
Loews Corp	L	225.51	62.65	14,128		0.40%			
Lowe's Cos Inc	LOW	585.98	234.27	137,278		1.88%		20.63%	
IDEX Corp	IEX	75.60	225.81	17,072	0.06%	1.13%	0.00%	10.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.95	188.42	93,071	0.32%	1.51%	0.00%	11.25%	0.04%
Masco Corp	MAS	224.93	60.68	13,649	0.05%	1.88%	0.00%	6.74%	0.00%
S&P Global Inc	SPGI	318.20	394.51	125,533	0.43%	0.91%	0.00%	13.72%	0.06%
Medtronic PLC	MDT	1,330.41	87.76	116,756	0.40%	3.14%	0.01%	3.23%	0.01%
Viatris Inc	VTRS	1,199.03	10.53	12,626		4.56%		-1.16%	
CVS Health Corp	CVS	1,282.03	74.69	95,754	0.33%	3.24%	0.01%	6.90%	0.02%
DuPont de Nemours Inc	DD	459.02	77.63	35,633	0.12%	1.85%	0.00%	7.53%	0.01%
Micron Technology Inc	MU	1,095.30	71.39	78,194		0.64%		-15.93%	
Motorola Solutions Inc	MSI	167.72	286.63	48,073		1.23%			
Cboe Global Markets Inc	CBOE	105.57	139.68	14,747		1.43%			
Laboratory Corp of America Holdings	LH	88.60	213.93	18,954		1.35%		-4.73%	
Newmont Corp	NEM	794.73	42.92	34,110	0.12%	3.73%	0.00%	11.86%	0.01%
NIKE Inc	NKE	1,225.07	110.39	135,236	0.46%	1.23%	0.01%	15.34%	0.07%
NiSource Inc	NI	413.06	27.84	11,500	0.04%	3.59%	0.00%	7.50%	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 Growth Rate	[11] Cap-Weighted Long-Term Growth Est.
Norfolk Southern Corp	NSC	227.02	232.22	52,717	0.18%	2.33%	0.00%	3.17%	0.01%
Principal Financial Group Inc	PFG	242.78	79.87	19,390	0.07%	3.26%	0.00%	7.61%	0.01%
Eversource Energy	ES	348.84	72.33	25,232	0.09%	3.73%	0.00%	5.96%	0.01%
Northrop Grumman Corp	NOC	151.30	445.00	67,329	0.23%	1.68%	0.00%	4.03%	0.01%
Wells Fargo & Co	WFC	3,667.70	45.80	167,987	0.57%	3.06%	0.02%	13.41%	0.08%
Nucor Corp	NUE	251.22	172.09	43,233		1.19%		-10.56%	
Occidental Petroleum Corp	OXY	891.75	63.13	56,296		1.14%		-14.19%	
Omnicom Group Inc	OMC	197.57	84.62	16,718	0.06%	3.31%	0.00%	6.31%	0.00%
ONEOK Inc	OKE	447.44	67.04	29,997	0.10%	5.70%	0.01%	8.77%	0.01%
Raymond James Financial Inc	RJF	208.50	110.07	22,950		1.53%			
PG&E Corp	PCG	2,568.99	17.61	45,240	0.15%			6.26%	0.01%
Parker-Hannifin Corp	PH	128.30	410.01	52,603	0.18%	1.44%	0.00%	14.56%	0.03%
Rollins Inc	ROL	492.82	40.83	20,122	0.07%	1.27%	0.00%	13.72%	0.01%
PPL Corp	PPL	737.07	27.53	20,291	0.07%	3.49%	0.00%	7.21%	0.00%
ConocoPhillips	COP	1,211.88	117.72	142,662		0.51%		-7.00%	
PulteGroup Inc	PHM	219.45	84.39	18,519		0.76%		-3.91%	
Pinnacle West Capital Corp	PNW	113.26	82.82	9,380	0.03%	4.18%	0.00%	6.16%	0.00%
PNC Financial Services Group Inc/The	PNC	398.00	136.89	54,482		4.53%			
PPG Industries Inc	PPG	235.51	143.90	33,890	0.12%	1.81%	0.00%	13.00%	0.02%
Progressive Corp/The	PGR	585.30	125.98	73,736		0.32%		38.28%	
Public Service Enterprise Group Inc	PEG	498.97	63.12	31,495	0.11%	3.61%	0.00%	5.05%	0.01%
Robert Half Inc	RHI	107.76	74.15	7,991	0.03%	2.59%	0.00%	0.78%	0.00%
Edison International	EIX	383.29	71.96	27,581	0.09%	4.10%	0.00%	5.35%	0.01%
Schlumberger NV	SLB	1,421.19	58.34	82,912		1.71%		27.56%	
Charles Schwab Corp/The	SCHW	1,769.14	66.10	116,940	0.40%	1.51%	0.01%	5.31%	0.02%
Sherwin-Williams Co/The	SHW	257.15	276.50	71,102	0.24%	0.88%	0.00%	8.49%	0.02%
West Pharmaceutical Services Inc	WST	73.86	368.04	27,184	0.09%	0.21%	0.00%	18.65%	0.02%
J M Smucker Co/The	SJM	102.05	150.65	15,373	0.05%	2.81%	0.00%	5.08%	0.00%
Snap-on Inc	SNA	52.92	272.44	14,417	0.05%	2.38%	0.00%	4.87%	0.00%
AMETEK Inc	AME	230.48	158.60	36,553	0.12%	0.63%	0.00%	6.86%	0.01%
Southern Co/The	SO	1,091.52	72.34	78,960	0.27%	3.87%	0.01%	4.50%	0.01%
Truist Financial Corp	TFC	1,331.98	33.22	44,248	0.15%	6.26%	0.01%	4.13%	0.01%
Southwest Airlines Co	LUV	595.63	34.16	20,347		2.11%		29.08%	
W R Berkley Corp	WRB	257.52	61.69	15,886	0.05%	0.71%	0.00%	12.50%	0.01%
Stanley Black & Decker Inc	SWK	153.14	99.27	15,203		3.26%			
Public Storage	PSA	175.81	281.75	49,535	0.17%	4.26%	0.01%	3.41%	0.01%
Arista Networks Inc	ANET	308.28	155.09	47,812	0.16%			18.07%	0.03%
Sysco Corp	SYY	506.68	76.31	38,665		2.62%		46.00%	
Corteva Inc	CTVA	710.68	56.43	40,104	0.14%	1.13%	0.00%	19.90%	0.03%
Texas Instruments Inc	TXN	907.97	180.00	163,434	0.56%	2.76%	0.02%	7.80%	0.04%
Textron Inc	TXT	198.07	77.77	15,404	0.05%	0.10%	0.00%	11.18%	0.01%
Thermo Fisher Scientific Inc	TMO	385.72	548.66	211,630		0.26%			
TJX Cos Inc/The	TJX	1,149.24	86.53	99,444	0.34%	1.54%	0.01%	10.00%	0.03%
Globe Life Inc	GL	95.56	112.17	10,718		0.80%			
Johnson Controls International plc	JCI	686.10	69.55	47,718	0.16%	2.13%	0.00%	14.69%	0.02%
Ulta Beauty Inc	ULTA	49.80	444.80	22,152	0.08%			6.09%	0.00%
Union Pacific Corp	UNP	609.46	232.02	141,406	0.48%	2.24%	0.01%	6.50%	0.03%
Keysight Technologies Inc	KEYS	178.37	161.08	28,732	0.10%			6.74%	0.01%
UnitedHealth Group Inc	UNH	931.03	506.37	471,447	1.61%	1.49%	0.02%	12.79%	0.21%
Marathon Oil Corp	MRO	617.60	26.27	16,224	0.06%	1.52%	0.00%	1.50%	0.00%
Bio-Rad Laboratories Inc	BIO	24.54	405.36	9,946					
Ventas Inc	VTR	400.05	48.52	19,411	0.07%	3.71%	0.00%	9.48%	0.01%
VF Corp	VFC	388.68	19.81	7,700	0.03%	6.06%	0.00%	1.44%	0.00%
Vulcan Materials Co	VMC	133.06	220.50	29,340		0.78%		21.48%	
Weyerhaeuser Co	WY	730.75	34.06	24,889		2.23%			
Whirlpool Corp	WHR	54.82	144.26	7,908		4.85%		-1.35%	
Williams Cos Inc/The	WMB	1,218.19	34.45	41,967	0.14%	5.20%	0.01%	3.50%	0.01%
Constellation Energy Corp	CEG	326.66	96.65	31,572		1.17%		-152.43%	
WEC Energy Group Inc	WEC	315.44	89.86	28,345	0.10%	3.47%	0.00%	6.26%	0.01%
Adobe Inc	ADBE	455.80	546.17	248,944	0.85%			16.88%	0.14%
AES Corp/The	AES	669.34	21.63	14,478	0.05%	3.07%	0.00%	9.12%	0.00%
Amgen Inc	AMGN	534.33	234.15	125,113	0.43%	3.64%	0.02%	4.00%	0.02%
Apple Inc	AAPL	15,728.70	196.45	3,089,904	10.53%	0.49%	0.05%	13.00%	1.37%
Autodesk Inc	ADSK	213.73	211.99	45,308	0.15%			16.39%	0.03%
Cintas Corp	CTAS	101.74	502.04	51,079	0.17%	1.08%	0.00%	9.74%	0.02%
Comcast Corp	CMCSA	4,115.69	45.26	186,276	0.63%	2.56%	0.02%	8.68%	0.06%
Molson Coors Beverage Co	TAP	200.38	69.77	13,981	0.05%	2.35%	0.00%	9.05%	0.00%
KLA Corp	KLAC	137.20	513.95	70,513	0.24%	1.01%	0.00%	9.27%	0.02%
Marriott International Inc/MD	MAR	303.35	201.81	61,220	0.21%	1.03%	0.00%	16.26%	0.03%
Fiserv Inc	FI	609.62	126.21	76,940	0.26%			14.63%	0.04%
McCormick & Co Inc/MD	MKC	251.10	89.48	22,468	0.08%	1.74%	0.00%	7.01%	0.01%
PACCAR Inc	PCAR	522.80	86.13	45,029	0.15%	1.25%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	443.15	560.67	248,460	0.85%	0.73%	0.01%	12.46%	0.11%
Stryker Corp	SYK	379.61	283.41	107,585	0.37%	1.06%	0.00%	8.82%	0.03%
Tyson Foods Inc	TSN	285.60	55.72	15,914		3.45%		-21.58%	
Lamb Weston Holdings Inc	LW	145.67	103.35	15,054	0.05%	1.08%	0.00%	12.14%	0.01%
Applied Materials Inc	AMAT	839.75	151.59	127,297	0.43%	0.84%	0.00%	1.87%	0.01%
American Airlines Group Inc	AAL	653.36	16.75	10,944				80.75%	
Cardinal Health Inc	CAH	254.60	91.47	23,288	0.08%	2.19%	0.00%	13.54%	0.01%
Cincinnati Financial Corp	CINF	156.86	107.58	16,875	0.06%	2.79%	0.00%	17.66%	0.01%
Paramount Global	PARA	610.85	16.03	9,792		1.25%		-20.15%	
DR Horton Inc	DHI	338.30	127.02	42,970		0.79%		-8.43%	
Electronic Arts Inc	EA	272.12	136.35	37,103	0.13%	0.56%	0.00%	7.73%	0.01%
Fair Isaac Corp	FICO	24.99	837.97	20,943					
Expeditors International of Washington Inc	EXPD	152.79	127.30	19,450		1.08%			
Fastenal Co	FAST	571.33	58.61	33,486		2.39%			
M&T Bank Corp	MTB	165.89	139.86	23,202	0.08%	3.72%	0.00%	11.10%	0.01%
Xcel Energy Inc	XEL	551.53	62.73	34,598	0.12%	3.32%	0.00%	6.35%	0.01%
Fifth Third Bancorp	FITB	680.85	29.10	19,813		4.54%		25.00%	
Gilead Sciences Inc	GILD	1,248.82	76.14	95,085	0.32%	3.94%	0.01%	0.42%	0.00%
Hasbro Inc	HAS	138.61	64.56	8,949	0.03%	4.34%	0.00%	6.66%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Growth Rate	Cap-Weighted Long-Term Growth Est.
Huntington Bancshares Inc/OH	HBAN	1,447.88	12.24	17,722		5.07%		-5.65%	
Welltower Inc	WELL	497.03	82.15	40,831	0.14%	2.97%	0.00%	10.64%	0.01%
Biogen Inc	BIIB	144.82	270.19	39,130	0.13%			1.73%	0.00%
Northern Trust Corp	NTRS	207.00	80.12	16,585	0.06%	3.74%	0.00%	13.00%	0.01%
Packaging Corp of America	PKG	89.93	153.35	13,791	0.05%	3.26%	0.00%	3.00%	0.00%
Paychex Inc	PAYX	360.55	125.47	45,238	0.15%	2.84%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1,114.00	132.17	147,237		2.42%		-0.48%	
Ross Stores Inc	ROST	340.66	114.64	39,053	0.13%	1.17%	0.00%	10.00%	0.01%
IDEXX Laboratories Inc	IDXX	83.01	554.73	46,045	0.16%			17.27%	0.03%
Starbucks Corp	SBUX	1,146.40	101.57	116,440	0.40%	2.09%	0.01%	17.52%	0.07%
KeyCorp	KEY	935.73	12.31	11,519	0.04%	6.66%	0.00%	7.53%	0.00%
Fox Corp	FOXA	269.06	33.45	9,000	0.03%	1.49%	0.00%	10.84%	0.00%
Fox Corp	FOX	235.58	31.41	7,400	0.03%	1.59%	0.00%	10.84%	0.00%
State Street Corp	STT	318.64	72.44	23,082	0.08%	3.81%	0.00%	6.16%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	424.17	22.07	9,361					
US Bancorp	USB	1,532.92	39.68	60,826	0.21%	4.84%	0.01%	8.00%	0.02%
A O Smith Corp	AOS	124.59	72.63	9,049		1.65%			
Gen Digital Inc	GEN	639.42	19.45	12,437		2.57%			
T Rowe Price Group Inc	TROW	224.30	123.26	27,647		3.96%		-1.18%	
Waste Management Inc	WM	405.06	163.79	66,345	0.23%	1.71%	0.00%	9.80%	0.02%
Constellation Brands Inc	STZ	183.30	272.80	50,005	0.17%	1.30%	0.00%	9.73%	0.02%
DENTSPLY SIRONA Inc	XRAY	212.48	41.52	8,822	0.03%	1.35%	0.00%	9.33%	0.00%
Zions Bancorp NA	ZION	148.14	38.25	5,667		4.29%		-3.00%	
Alaska Air Group Inc	ALK	127.35	48.63	6,193				23.98%	
Invesco Ltd	IVZ	448.60	16.80	7,536	0.03%	4.76%	0.00%	4.54%	0.00%
Intuit Inc	INTU	280.06	511.70	143,307	0.49%	0.61%	0.00%	15.94%	0.08%
Morgan Stanley	MS	1,670.11	91.56	152,916	0.52%	3.71%	0.02%	3.76%	0.02%
Microchip Technology Inc	MCHP	545.38	93.94	51,233	0.17%	1.63%	0.00%	8.64%	0.02%
Chubb Ltd	CB	410.74	204.41	83,958	0.29%	1.68%	0.00%	14.00%	0.04%
Hologic Inc	HOLX	246.12	79.42	19,547				-26.13%	
Citizens Financial Group Inc	CFG	474.68	31.84	15,114		5.28%		-6.14%	
O'Reilly Automotive Inc	ORLY	60.40	925.79	55,920	0.19%			11.57%	0.02%
Allstate Corp/The	ALL	262.85	112.68	29,618		3.16%		48.41%	
Equity Residential	EQR	379.03	65.94	24,993	0.09%	4.02%	0.00%	5.68%	0.00%
BorgWarner Inc	BWA	234.37	46.50	10,898	0.04%	0.95%	0.00%	12.56%	0.00%
Keurig Dr Pepper Inc	KDP	1,397.26	34.01	47,521	0.16%	2.35%	0.00%	6.35%	0.01%
Organon & Co	OGN	255.06	21.98	5,606	0.02%	5.10%	0.00%	5.48%	0.00%
Host Hotels & Resorts Inc	HST	711.24	18.40	13,087		3.26%			
Incyte Corp	INCY	223.09	63.72	14,215				66.14%	
Simon Property Group Inc	SPG	326.99	124.60	40,743	0.14%	5.94%	0.01%	3.52%	0.00%
Eastman Chemical Co	EMN	118.56	85.58	10,146	0.03%	3.69%	0.00%	5.93%	0.00%
AvalonBay Communities Inc	AVB	142.00	188.65	26,788	0.09%	3.50%	0.00%	8.50%	0.01%
Prudential Financial Inc	PRU	365.00	96.49	35,219	0.12%	5.18%	0.01%	11.13%	0.01%
United Parcel Service Inc	UPS	724.78	187.13	135,628		3.46%		-0.78%	
Walgreens Boots Alliance Inc	WBA	863.26	29.97	25,872		6.41%		-6.57%	
STERIS PLC	STE	98.65	225.55	22,251		0.92%			
McKesson Corp	MCK	135.51	402.40	54,530	0.19%	0.62%	0.00%	9.80%	0.02%
Lockheed Martin Corp	LMT	251.83	446.37	112,410	0.38%	2.69%	0.01%	6.99%	0.03%
AmerisourceBergen Corp	ABC	201.98	186.90	37,751	0.13%	1.04%	0.00%	8.93%	0.01%
Capital One Financial Corp	COF	381.44	117.02	44,636		2.05%		-3.03%	
Waters Corp	WAT	59.03	276.21	16,306	0.06%			6.61%	0.00%
Nordson Corp	NDSN	56.99	251.61	14,340		1.03%		48.00%	
Dollar Tree Inc	DLTR	220.39	154.33	34,012	0.12%			9.23%	0.01%
Darden Restaurants Inc	DRI	121.07	168.92	20,451	0.07%	3.10%	0.00%	10.79%	0.01%
Evergy Inc	EVRG	229.58	59.97	13,768	0.05%	4.09%	0.00%	4.74%	0.00%
Match Group Inc	MTCH	278.46	46.51	12,951					
Domino's Pizza Inc	DPZ	35.09	396.74	13,923	0.05%	1.22%	0.00%	13.94%	0.01%
NVR Inc	NVR	3.26	6,306.44	20,565				-3.60%	
NetApp Inc	NTAP	210.82	78.01	16,446	0.06%	2.56%	0.00%	7.40%	0.00%
DXC Technology Co	DXC	210.07	27.65	5,809	0.02%			11.42%	0.00%
Old Dominion Freight Line Inc	ODFL	109.65	419.49	45,998	0.16%	0.38%	0.00%	4.45%	0.01%
DaVita Inc	DVA	90.70	101.99	9,250	0.03%			14.60%	0.00%
Hartford Financial Services Group Inc/The	HIG	305.82	71.88	21,982	0.07%	2.37%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.62	61.40	17,906	0.06%	4.03%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	231.87	180.00	41,737	0.14%	1.47%	0.00%	18.89%	0.03%
Cadence Design Systems Inc	CDNS	271.79	234.01	63,602	0.22%			19.00%	0.04%
Tyler Technologies Inc	TYL	42.08	396.63	16,689					
Universal Health Services Inc	UHS	62.93	138.96	8,745	0.03%	0.58%	0.00%	8.65%	0.00%
Skyworks Solutions Inc	SWKS	159.16	114.37	18,203	0.06%	2.17%	0.00%	9.40%	0.01%
Quest Diagnostics Inc	DGX	112.24	135.21	15,175		2.10%		-20.34%	
Activision Blizzard Inc	ATVI	786.80	91.77	72,204	0.25%	1.08%	0.00%	5.00%	0.01%
Rockwell Automation Inc	ROK	114.88	336.29	38,631	0.13%	1.40%	0.00%	18.98%	0.02%
Kraft Heinz Co/The	KHC	1,227.24	36.18	44,401	0.15%	4.42%	0.01%	3.92%	0.01%
American Tower Corp	AMT	466.16	190.31	88,714	0.30%	3.30%	0.01%	11.96%	0.04%
Regeneron Pharmaceuticals Inc	REGN	107.89	741.91	80,046	0.27%			7.00%	0.02%
Amazon.com Inc	AMZN	10,260.35	133.68	1,371,604				59.71%	
Jack Henry & Associates Inc	JKHY	72.88	167.57	12,212	0.04%	1.24%	0.00%	5.62%	0.00%
Ralph Lauren Corp	RL	40.39	131.33	5,304	0.02%	2.28%	0.00%	10.38%	0.00%
Boston Properties Inc	BXP	156.84	66.63	10,450	0.04%	5.88%	0.00%	1.21%	0.00%
Amphenol Corp	APH	596.45	88.31	52,673	0.18%	0.95%	0.00%	5.46%	0.01%
Howmet Aerospace Inc	HWM	413.29	51.10	21,118	0.07%	0.31%	0.00%	16.69%	0.01%
Pioneer Natural Resources Co	PXD	233.74	225.67	52,747		5.92%		-2.23%	
Valero Energy Corp	VLO	353.13	127.89	45,162		3.19%		-7.69%	
Synopsys Inc	SNPS	152.16	451.80	68,746	0.23%			16.62%	0.04%
Etsy Inc	ETSY	123.35	101.65	12,539	0.04%			14.97%	0.01%
CH Robinson Worldwide Inc	CHRW	116.44	100.18	11,665	0.04%	2.44%	0.00%	10.00%	0.00%
Accenture PLC	ACN	630.80	316.35	199,552	0.68%	1.42%	0.01%	10.00%	0.07%
TransDigm Group Inc	TDG	54.93	899.72	49,420				24.54%	
Yum! Brands Inc	YUM	280.09	137.67	38,560	0.13%	1.76%	0.00%	11.71%	0.02%
Prologis Inc	PLD	923.45	124.75	115,200	0.39%	2.79%	0.01%	8.95%	0.04%
FirstEnergy Corp	FE	572.84	39.39	22,564		3.96%		-0.33%	

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 Growth Rate	[11] Cap-Weighted Long-Term Growth Est.
VeriSign Inc	VRSN	103.13	210.95	21,756	0.07%			12.30%	0.01%
Quanta Services Inc	PWR	145.18	201.62	29,270		0.16%			
Henry Schein Inc	HSIC	131.00	78.79	10,322	0.04%			5.04%	0.00%
Ameren Corp	AEE	262.48	85.67	22,486	0.08%	2.94%	0.00%	6.93%	0.01%
ANSYS Inc	ANSS	86.66	342.10	29,647	0.10%			10.26%	0.01%
FactSet Research Systems Inc	FDS	38.15	435.04	16,595	0.06%	0.90%	0.00%	11.97%	0.01%
NVIDIA Corp	NVDA	2,470.00	467.29	1,154,206		0.03%		35.00%	
Sealed Air Corp	SEE	144.39	45.62	6,587	0.02%	1.75%	0.00%	4.30%	0.00%
Cognizant Technology Solutions Corp	CTSH	507.48	66.03	33,509	0.11%	1.76%	0.00%	12.00%	0.01%
Intuitive Surgical Inc	ISRG	351.36	324.40	113,980	0.39%			16.14%	0.06%
Take-Two Interactive Software Inc	TTWO	169.83	152.94	25,974				-1.04%	
Republic Services Inc	RSG	316.28	151.11	47,793	0.16%	1.42%	0.00%	9.09%	0.01%
eBay Inc	EBAY	532.16	44.51	23,686	0.08%	2.25%	0.00%	6.50%	0.01%
Goldman Sachs Group Inc/The	GS	332.45	355.87	118,308	0.40%	3.09%	0.01%	9.00%	0.04%
SBA Communications Corp	SBAC	108.34	218.95	23,721		1.55%			
Sempra	SRE	314.65	149.02	46,889	0.16%	3.19%	0.01%	4.04%	0.01%
Moody's Corp	MCO	183.50	352.75	64,730	0.22%	0.87%	0.00%	13.87%	0.03%
ON Semiconductor Corp	ON	431.53	107.75	46,497	0.16%			8.50%	0.01%
Booking Holdings Inc	BKNG	36.93	2,970.80	109,724	0.37%			20.00%	0.07%
F5 Inc	FFIV	59.30	158.24	9,383	0.03%			10.19%	0.00%
Akamai Technologies Inc	AKAM	156.30	94.50	14,771	0.05%			10.00%	0.01%
Charles River Laboratories International Inc	CRL	51.18	209.54	10,725	0.04%			14.00%	0.01%
MarketAxess Holdings Inc	MKTX	37.68	268.50	10,116		1.07%			
Devon Energy Corp	DVN	641.70	54.00	34,652		5.33%		20.68%	
Bio-Techne Corp	TECH	157.44	83.40	13,130		0.38%			
Alphabet Inc	GOOGL	5,933.00	132.72	787,428	2.68%			16.51%	0.44%
Teleflex Inc	TFX	46.97	251.17	11,798	0.04%	0.54%	0.00%	6.15%	0.00%
Bunge Ltd	BG	150.62	108.67	16,368		2.44%		-5.81%	
Allegion plc	ALLE	87.78	116.86	10,258	0.03%	1.54%	0.00%	5.43%	0.00%
Netflix Inc	NFLX	443.15	438.97	194,528				32.28%	
Warner Bros Discovery Inc	WBD	2,436.11	13.07	31,840					
Agilent Technologies Inc	A	295.38	121.77	35,968	0.12%	0.74%	0.00%	14.00%	0.02%
Trimble Inc	TRMB	247.75	53.80	13,329					
Elevance Health Inc	ELV	235.65	471.63	111,139	0.38%	1.26%	0.00%	12.07%	0.05%
CME Group Inc	CME	359.72	198.96	71,569	0.24%	2.21%	0.01%	6.14%	0.01%
Juniper Networks Inc	JNPR	321.36	27.80	8,934	0.03%	3.17%	0.00%	7.89%	0.00%
BlackRock Inc	BLK	149.76	738.85	110,652	0.38%	2.71%	0.01%	9.20%	0.03%
DTE Energy Co	DTE	206.11	114.30	23,558	0.08%	3.33%	0.00%	6.50%	0.01%
Celanese Corp	CE	108.79	125.39	13,641	0.05%	2.23%	0.00%	10.27%	0.00%
Nasdaq Inc	NDAQ	490.77	50.49	24,779	0.08%	1.74%	0.00%	2.68%	0.00%
Philip Morris International Inc	PM	1,552.35	99.72	154,800	0.53%	5.09%	0.03%	7.99%	0.04%
Ingersoll Rand Inc	IR	404.52	65.27	26,403		0.12%			
Salesforce Inc	CRM	974.00	225.01	219,160				22.50%	
Huntington Ingalls Industries Inc	HII	39.89	229.67	9,162		2.16%		40.00%	
Roper Technologies Inc	ROP	106.59	493.05	52,555		0.55%			
MetLife Inc	MET	765.82	62.97	48,224	0.16%	3.30%	0.01%	8.89%	0.01%
Tapestry Inc	TPR	231.80	43.15	10,002	0.03%	2.78%	0.00%	14.00%	0.00%
CSX Corp	CSX	2,006.33	33.32	66,851	0.23%	1.32%	0.00%	3.11%	0.01%
Edwards Lifesciences Corp	EW	607.92	82.07	49,892	0.17%			10.65%	0.02%
Ameriprise Financial Inc	AMP	104.18	348.45	36,301	0.12%	1.55%	0.00%	17.59%	0.02%
Zebra Technologies Corp	ZBRA	51.43	307.96	15,838					
Zimmer Biomet Holdings Inc	ZBH	208.57	138.15	28,814	0.10%	0.69%	0.00%	9.20%	0.01%
Camden Property Trust	CPT	106.76	109.09	11,647	0.04%	3.67%	0.00%	3.48%	0.00%
CBRE Group Inc	CBRE	309.84	83.31	25,813					
Mastercard Inc	MA	934.85	394.28	368,592	1.26%	0.58%	0.01%	18.18%	0.23%
CarMax Inc	KMX	158.21	82.61	13,070	0.04%			15.54%	0.01%
Intercontinental Exchange Inc	ICE	559.87	114.80	64,273	0.22%	1.46%	0.00%	11.21%	0.02%
Fidelity National Information Services Inc	FIS	592.44	60.38	35,771	0.12%	3.44%	0.00%	3.02%	0.00%
Chipotle Mexican Grill Inc	CMG	27.59	1,962.28	54,135				26.95%	
Wynn Resorts Ltd	WYNN	113.80	108.98	12,402		0.92%			
Live Nation Entertainment Inc	LYV	230.15	87.75	20,196					
Assurant Inc	AIZ	53.15	134.51	7,149	0.02%	2.08%	0.00%	11.43%	0.00%
NRG Energy Inc	NRG	230.23	37.99	8,747	0.03%	3.97%	0.00%	4.03%	0.00%
Monster Beverage Corp	MNST	1,046.71	57.49	60,175				22.52%	
Regions Financial Corp	RF	938.31	20.37	19,113	0.07%	4.71%	0.00%	2.08%	0.00%
Baker Hughes Co	BKR	1,009.65	35.79	36,136		2.24%		57.62%	
Mosaic Co/The	MOS	332.11	40.76	13,537	0.05%	1.96%	0.00%	7.00%	0.00%
Expedia Group Inc	EXPE	142.60	122.53	17,473	0.06%			17.50%	0.01%
CF Industries Holdings Inc	CF	194.92	82.08	15,999	0.05%	1.95%	0.00%	6.00%	0.00%
APA Corp	APA	308.60	40.49	12,495		2.47%		-2.60%	
Leidos Holdings Inc	LDOS	137.17	93.53	12,829	0.04%	1.54%	0.00%	5.95%	0.00%
Alphabet Inc	GOOG	5,801.00	133.11	772,171	2.63%			16.51%	0.43%
First Solar Inc	FSLR	106.83	207.40	22,157				44.40%	
Cooper Cos Inc/The	COO	49.51	391.26	19,371	0.07%	0.02%	0.00%	9.00%	0.01%
TE Connectivity Ltd	TEL	313.94	143.49	45,047	0.15%	1.64%	0.00%	3.10%	0.00%
Discover Financial Services	DFS	249.95	105.55	26,382	0.09%	2.65%	0.00%	6.85%	0.01%
Linde PLC	LIN	487.95	390.67	190,626	0.65%	1.31%	0.01%	13.50%	0.09%
Visa Inc	V	1,606.79	237.73	381,982	1.30%	0.76%	0.01%	14.91%	0.19%
Mid-America Apartment Communities Inc	MAA	116.68	149.66	17,462		3.74%			
Xylem Inc/NY	XYL	239.35	112.75	26,987		1.17%			
Marathon Petroleum Corp	MPC	424.28	133.02	56,438		2.26%		29.12%	
Advanced Micro Devices Inc	AMD	1,610.36	114.40	184,225	0.63%			6.10%	0.04%
Tractor Supply Co	TSCO	109.57	223.99	24,542	0.08%	1.84%	0.00%	7.63%	0.01%
ResMed Inc	RMD	147.07	222.35	32,701	0.11%	0.79%	0.00%	11.62%	0.01%
Mettler-Toledo International Inc	MTD	21.87	1,257.47	27,495	0.09%			9.75%	0.01%
VICI Properties Inc	VICI	1,013.43	31.48	31,903	0.11%	4.96%	0.01%	6.33%	0.01%
Copart Inc	CPRT	477.44	88.39	42,201	0.14%			10.00%	0.01%
Jacobs Solutions Inc	J	126.85	125.41	15,908	0.05%	0.83%	0.00%	9.26%	0.01%
Fortinet Inc	FTNT	785.20	77.72	61,025	0.21%			18.50%	0.04%
Albemarle Corp	ALB	117.34	212.28	24,908		0.75%		36.57%	
Moderna Inc	MRNA	381.21	117.66	44,853				-65.68%	

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Growth Rate	Cap-Weighted Long-Term Growth Est.
Essex Property Trust Inc	ESS	64.18	243.55	15,632	0.05%	3.79%	0.00%	9.80%	0.01%
CoStar Group Inc	CSGP	408.34	83.97	34,288	0.12%			20.00%	0.02%
Realty Income Corp	O	673.22	60.97	41,046	0.14%	5.03%	0.01%	0.25%	0.00%
Westrock Co	WRK	256.13	33.29	8,527		3.30%		-24.09%	
Westinghouse Air Brake Technologies Corp	WAB	179.13	118.44	21,216	0.07%	0.57%	0.00%	11.33%	0.01%
Pool Corp	POOL	39.05	384.74	15,025		1.14%		-4.92%	
Western Digital Corp	WDC	319.94	42.56	13,617				-22.46%	
PepsiCo Inc	PEP	1,376.58	187.46	258,054	0.88%	2.70%	0.02%	8.64%	0.08%
Diamondback Energy Inc	FANG	181.09	147.32	26,679	0.09%	2.28%	0.00%	2.00%	0.00%
Palo Alto Networks Inc	PANW	305.86	249.96	76,452				30.00%	
ServiceNow Inc	NOW	204.00	583.00	118,932				30.00%	
Church & Dwight Co Inc	CHD	246.05	95.67	23,539	0.08%	1.14%	0.00%	5.85%	0.00%
Federal Realty Investment Trust	FRT	81.52	101.52	8,275	0.03%	4.26%	0.00%	6.20%	0.00%
MGM Resorts International	MGM	363.80	50.77	18,470					
American Electric Power Co Inc	AEP	515.18	84.74	43,656	0.15%	3.92%	0.01%	5.61%	0.01%
SolarEdge Technologies Inc	SEDG	56.35	241.46	13,605				36.57%	
Invitation Homes Inc	INVH	611.96	35.50	21,724	0.07%	2.93%	0.00%	7.96%	0.01%
PTC Inc	PTC	118.35	145.81	17,257	0.06%			16.99%	0.01%
JB Hunt Transport Services Inc	JBHT	103.35	203.52	21,033	0.07%	0.83%	0.00%	15.00%	0.01%
Lam Research Corp	LRCX	133.30	718.49	95,773		0.96%			
Mohawk Industries Inc	MHK	63.68	106.34	6,772				-1.83%	
Pentair PLC	PNR	165.11	69.50	11,475	0.04%	1.27%	0.00%	6.14%	0.00%
GE HealthCare Technologies Inc	GEHC	454.84	78.00	35,477	0.12%	0.15%	0.00%	13.50%	0.02%
Vertex Pharmaceuticals Inc	VRTX	257.55	352.34	90,746	0.31%			14.12%	0.04%
Amcor PLC	AMCR	1,471.44	10.26	15,097		4.78%		-0.83%	
Meta Platforms Inc	META	2,222.58	318.60	708,115				21.72%	
T-Mobile US Inc	TMUS	1,176.46	137.77	162,080	0.55%			5.00%	0.03%
United Rentals Inc	URI	68.28	464.68	31,730		1.27%		21.02%	
Alexandria Real Estate Equities Inc	ARE	173.03	125.68	21,746	0.07%	3.95%	0.00%	4.05%	0.00%
Honeywell International Inc	HON	663.96	194.13	128,895	0.44%	2.12%	0.01%	9.50%	0.04%
Delta Air Lines Inc	DAL	643.42	46.26	29,765		0.86%		37.89%	
United Airlines Holdings Inc	UAL	326.73	54.31	17,745				67.35%	
Seagate Technology Holdings PLC	STX	207.08	63.50	13,150	0.04%	4.41%	0.00%	1.21%	0.00%
News Corp	NWS	192.52	20.11	3,871	0.01%	0.99%	0.00%	1.60%	0.00%
Centene Corp	CNC	541.48	68.09	36,869	0.13%			8.43%	0.01%
Martin Marietta Materials Inc	MLM	61.80	446.46	27,593	0.09%	0.59%	0.00%	19.03%	0.02%
Teradyne Inc	TER	155.04	112.94	17,510	0.06%	0.39%	0.00%	20.00%	0.01%
PayPal Holdings Inc	PYPL	1,115.71	75.82	84,593	0.29%			15.72%	0.05%
Tesla Inc	TSLA	3,173.99	267.43	848,821	2.89%			16.00%	0.46%
Arch Capital Group Ltd	ACGL	372.90	77.69	28,971	0.10%			14.50%	0.01%
Dow Inc	DOW	703.08	56.47	39,703	0.14%	4.96%	0.01%	2.78%	0.00%
Everest Group Ltd	EG	43.40	360.51	15,646		1.83%		33.49%	
Teledyne Technologies Inc	TDY	47.08	384.53	18,102	0.06%			6.47%	0.00%
News Corp	NWSA	380.95	19.82	7,550	0.03%	1.01%	0.00%	1.60%	0.00%
Exelon Corp	EXC	994.30	41.86	41,621	0.14%	3.44%	0.00%	5.30%	0.01%
Global Payments Inc	GPN	261.95	110.25	28,880	0.10%	0.91%	0.00%	13.69%	0.01%
Crown Castle Inc	CCI	434.00	108.29	46,998		5.78%			
Aptiv PLC	APTV	270.51	109.49	29,618	0.10%			11.94%	0.01%
Advance Auto Parts Inc	AAP	59.44	74.39	4,422		1.34%		-7.41%	
Align Technology Inc	ALGN	76.52	377.89	28,915	0.10%			17.54%	0.02%
Illumina Inc	ILMN	158.10	192.15	30,379					
Targa Resources Corp	TRGP	226.02	81.99	18,531		2.44%			
LKQ Corp	LKQ	267.56	54.79	14,659		2.01%			
Zoetis Inc	ZTS	462.11	188.09	86,919	0.30%	0.80%	0.00%	10.91%	0.03%
Digital Realty Trust Inc	DLR	299.24	124.62	37,291	0.13%	3.92%	0.00%	6.59%	0.01%
Equinix Inc	EQIX	93.52	809.92	75,746	0.26%	1.68%	0.00%	14.96%	0.04%
Las Vegas Sands Corp	LVS	764.45	59.81	45,722		0.33%			
Molina Healthcare Inc	MOH	58.30	304.49	17,752	0.06%			11.74%	0.01%

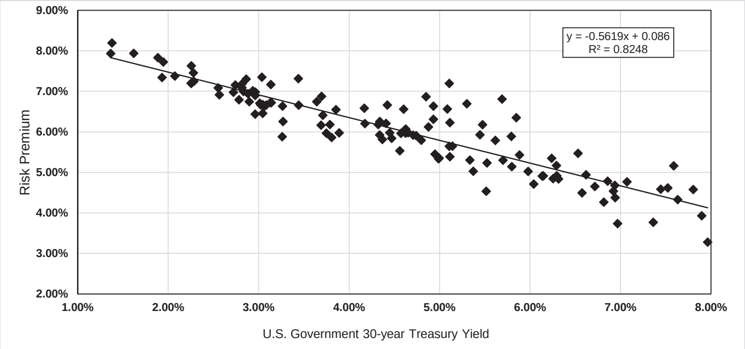
Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of July 31, 2023
[5] Source: Bloomberg Professional as of July 31, 2023
[6] Equals [4] x [5]
[7] Equals weight in the S&P 500
[8] Source: Bloomberg Professional as of July 31, 2023
[9] Equals [7] x [8]
[10] Source: Bloomberg Professional, as of July 31, 2023
[11] Equals [7] x [10]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
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%
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%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
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%
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	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.67%	1.95%	7.73%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
2022.4	9.87%	3.89%	5.98%
2023.1	9.72%	3.75%	5.97%
2023.2	9.67%	3.81%	5.86%
AVERAGE	10.59%	4.54%	6.05%
MEDIAN	10.55%	4.59%	6.17%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.908174
R Square	0.824780
Adjusted R Square	0.823367
Standard Error	0.004285
Observations	126

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010715	0.010715	583.682526	0.000000
Residual	124	0.002276	0.000018		
Total	125	0.012991			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0860	0.0011	76.56	0.00000	0.08378	0.08823	0.08378	0.08823
U.S. Govt. 30-year Treasury	(0.5619)	0.0233	(24.16)	0.00000	(0.60790)	(0.51583)	(0.60790)	(0.51583)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.92%	6.40%	10.32%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024) [5]	3.90%	6.41%	10.31%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.47%	10.27%
AVERAGE			10.30%

Notes:
[1] Source: Regulatory Research Associates, rate cases through July 31, 2023
[2] Source: 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] Source: S&P Capital IQ Pro, 30-day average as of July 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 8, August 1, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[7] See notes [4], [5] & [6]
[8] Equals 0.086007 + (-0.561864 x Column [7])
[9] Equals Column [7] + Column [8]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
ALLETE, Inc.	ALE	3.33	1.23
Alliant Energy Corporation	LNT	13.46	2.13
Ameren Corporation	AEE	22.10	2.08
American Electric Power Company, Inc.	AEP	43.95	1.85
Avista Corporation	AVA	2.95	1.24
CMS Energy Corporation	CMS	17.62	2.57
Duke Energy Corporation	DUK	70.78	1.50
Entergy Corporation	ETR	21.14	1.62
Evergy, Inc.	EVRG	13.64	1.44
IDACORP, Inc.	IDA	5.24	1.86
NextEra Energy, Inc.	NEE	149.35	3.46
NorthWestern Corporation	NWE	3.42	1.27
OGE Energy Corporation	OGE	7.24	1.66
Pinnacle West Capital Corporation	PNW	9.38	1.55
Portland General Electric Company	POR	4.60	1.47
Southern Company	SO	77.65	2.54
Xcel Energy Inc.	XEL	34.85	2.07
Average		29.45	1.85
Median		13.64	1.66
Otter Tail Power Corporation	OTTR	3.32	2.63

OTP		
Test Year Rate Base ($millions)	[3]	$ 661.77
Proposed Common Equity Ratio	[4]	53.50%
Common Equity ($ millions)	[5]	$ 354.05
Implied Market Capitalization	[6]	$ 586.65
Market Capitalization of Proxy Group (median) ($millions)	[7]	$ 13,644.96
In % of Proxy Group Market Capitalization (median)	[8]	4.30%

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10		[9] Market Capitalization of Largest Company ($ millions)	[10] Size Premium
1-Largest		2,203,381.29	-0.26%
2		31,316.51	0.45%
3		12,323.85	0.57%
4		5,916.02	0.58%
5		3,769.88	0.93%
6		2,365.08	1.16%
7		1,389.12	1.37%
8		782.38	1.18%
9		373.88	2.15%
10-Smallest		218.23	4.83%
OTP - Implied Market Capitalization	[6]	586.65	1.18%
Proxy Group Market Capitalization (median)	[7]	13,644.96	0.45%
Size Premium	[11]		0.73%

Notes:
[1]-[2] S&P Capital IQ Pro, equals 30-day average as of July 31, 2023
[3] Data provided by the Company
[4] Data provided by the Company
[5] Equals [3] x [4]
[6] Equals [5] x median market-to-book ratio of proxy group
[7] Equals median market capitalization of proxy group x 1000
[8] Equals [6] / [7]
[9]-[10] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2022
[11] Size Premium of OTP less Size Premium of Proxy Group

TRADING VOLUME ANALYSIS

Average Since	Proxy Group		OTTR		OTTR/Proxy Group	
	Daily Average Volume Traded (Millions)	Daily Average Volume Traded as % of Shares Outstanding	Daily Average Volume Traded (Millions)	Daily Average Volume Traded as % of Shares Outstanding	By Volume	By Volume As % of Shares Outs.
30-Day Avg.	2.04	0.633%	0.17	0.418%	9%	66%
90-day Avg.	1.87	0.559%	0.17	0.416%	9%	74%
180-day Avg.	1.95	0.600%	0.26	0.621%	13%	104%
2023 YTD	1.96	0.595%	0.28	0.683%	15%	115%
Jan 2022 - Present	2.01	0.595%	0.21	0.497%	10%	84%
Jan 2021 - Present	1.96	0.587%	0.17	0.412%	9%	70%
Jan 2020 - Present	2.03	0.613%	0.16	0.389%	8%	63%
Jan 2019 - Present	2.02	0.612%	0.14	0.351%	7%	57%

Notes:

[1] Source: S&P Capital IQ, as of July 31, 2023

[2] Daily Average Volumes for OTTR excludes 2/17/2023 through 2/23/2023. The addition of OTTR to the S&P SmallCap 600 caused a brief significant increase in trading volumes for OTTR between 2/17/2023 and 2/23/2023.

INSTITUTIONAL OWNERSHIP ANALYSIS

		[1]	[2]
Company	Ticker	Institutional Ownership by Percent Shares Held	Rank
ALLETE, Inc.	ALE	77.26%	13
Alliant Energy Corporation	LNT	78.36%	12
Ameren Corporation	AEE	79.34%	10
American Electric Power Company, Inc.	AEP	75.87%	14
Avista Corporation	AVA	79.94%	8
CMS Energy Corporation	CMS	98.84%	3
Duke Energy Corporation	DUK	64.82%	16
Entergy Corporation	ETR	88.14%	4
Evergy, Inc.	EVRG	84.22%	6
IDACORP, Inc.	IDA	83.59%	7
NextEra Energy, Inc.	NEE	79.70%	9
NorthWestern Corporation	NWE	98.97%	2
OGE Energy Corporation	OGE	68.40%	15
Pinnacle West Capital Corporation	PNW	88.12%	5
Portland General Electric Company	POR	100.00%	1
Southern Company	SO	64.33%	17
Xcel Energy Inc.	XEL	79.23%	11
Otter Tail Corporation	OTTR	60.74%	18
Average Excl. OTTR		81.71%	

Notes:

[1] Source: S&P Capital IQ Pro, as of September 14, 2023.

[2] The proxy group companies are ranked with 1 representing the highest level of institutional ownership and 18 representing the lowest.

[3] For all % greater than 100%, Brattle manually adjusted the values to 100%.

2024-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	
		2022	2024	2025	2026	2027	2024-27 Cap. Ex. / 2022 Net Plant	Rank
ALLETE, Inc.	ALE							
Capital Spending per Share			$5.95	$6.60	$7.25	$7.25		
Common Shares Outstanding			59.00	60.00	61.00	61.00		
Capital Expenditures			$351.1	$396.0	$442.3	$442.3	32.60%	2
Net Plant		$5,004.0						
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.80	$5.60	$5.40	$5.40		
Common Shares Outstanding			256.00	256.50	257.00	257.00		
Capital Expenditures			$1,484.8	$1,436.4	$1,387.8	$1,387.8	35.06%	4
Net Plant		$16,247.0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.55	$12.78	$13.00	$13.00		
Common Shares Outstanding			269.00	277.00	285.00	285.00		
Capital Expenditures			$3,376.0	$3,538.7	$3,705.0	$3,705.0	45.82%	13
Net Plant		$31,262.0						
American Electric Power Company	AEP							
Capital Spending per Share			$14.15	$14.08	$14.00	$14.00		
Common Shares Outstanding			530.00	540.00	550.00	550.00		
Capital Expenditures			$7,499.5	$7,600.5	$7,700.0	$7,700.0	42.79%	11
Net Plant		$71,283.0						
Avista Corporation	AVA							
Capital Spending per Share			$6.55	$6.68	$6.80	$6.80		
Common Shares Outstanding			78.50	81.75	85.00	85.00		
Capital Expenditures			$514.2	$545.7	$578.0	$578.0	40.70%	7
Net Plant		$5,444.7						
CMS Energy Corporation	CMS							
Capital Spending per Share			$9.50	$9.63	$9.75	$9.75		
Common Shares Outstanding			295.00	297.50	300.00	300.00		
Capital Expenditures			$2,802.5	$2,863.4	$2,925.0	$2,925.0	50.70%	16
Net Plant		$22,713.0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$17.60	$17.18	$16.75	$16.75		
Common Shares Outstanding			770.00	770.00	770.00	770.00		
Capital Expenditures			$13,552.0	$13,224.8	$12,897.5	$12,897.5	47.04%	14
Net Plant		$111,748.0						
Entergy Corporation	ETR							
Capital Spending per Share			$19.00	$19.38	$19.75	$19.75		
Common Shares Outstanding			218.00	224.00	230.00	230.00		
Capital Expenditures			$4,142.0	$4,340.0	$4,542.5	$4,542.5	41.36%	8
Net Plant		$42,477.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$9.25	$9.38	$9.50	$9.50		
Common Shares Outstanding			230.00	230.00	230.00	230.00		
Capital Expenditures			$2,127.5	$2,156.3	$2,185.0	$2,185.0	39.09%	6
Net Plant		$22,137.0						
IDACORP, Inc.	IDA							
Capital Spending per Share			$16.00	$13.50	$11.00	$11.00		
Common Shares Outstanding			51.50	52.25	53.00	53.00		
Capital Expenditures			$824.0	$705.4	$583.0	$583.0	52.10%	17
Net Plant		$5,173.0						

2024-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	
		2022	2024	2025	2026	2027	2024-27 Cap. Ex. / 2022 Net Plant	Rank
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$9.50	$9.63	$9.75	$9.75		
Common Shares Outstanding			2025.00	2037.50	2050.00	2050.00		
Capital Expenditures			$19,237.5	$19,610.9	$19,987.5	$19,987.5	70.97%	18
Net Plant		$111,059.0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$7.50	$7.00	$6.50	$6.50		
Common Shares Outstanding			62.00	62.00	62.00	62.00		
Capital Expenditures			$465.0	$434.0	$403.0	$403.0	30.14%	1
Net Plant		$5,657.5						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75		
Common Shares Outstanding			200.20	200.20	200.20	200.20		
Capital Expenditures			$951.0	$951.0	$951.0	$951.0	36.07%	5
Net Plant		$10,546.8						
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$15.00	$15.00	$15.00	$15.00		
Common Shares Outstanding			118.00	119.00	120.00	120.00		
Capital Expenditures			$1,770.0	$1,785.0	$1,800.0	$1,800.0	42.45%	10
Net Plant		$16,854.0						
Portland General Electric Company	POR							
Capital Spending per Share			$10.00	$10.00	$10.00	$10.00		
Common Shares Outstanding			99.50	99.75	100.00	100.00		
Capital Expenditures			$995.0	$997.5	$1,000.0	$1,000.0	47.16%	15
Net Plant		$8,465.0						
Southern Company	SO							
Capital Spending per Share			$7.85	$7.68	$7.50	$7.50		
Common Shares Outstanding			1070.00	1070.00	1070.00	1070.00		
Capital Expenditures			$8,399.5	$8,212.3	$8,025.0	$8,025.0	34.54%	3
Net Plant		$94,570.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$9.25	$9.38	$9.50	$9.50		
Common Shares Outstanding			553.00	556.50	560.00	560.00		
Capital Expenditures			$5,115.3	$5,217.2	$5,320.0	$5,320.0	43.46%	12
Net Plant		$48,253.0						
Otter Tail Power Company	OTP							
Capital Expenditures [7]			$247.00	$208.00	$239.00	$194.00	42.33%	9
Net Plant [8]		$2,098.0						
OTP CapEx Total (2024 - 2027)							$888.0	
OTP CapEx Annual Average							$222.0	
Proxy Group Median							42.45%	
OTP as % Proxy Group Median							1.00	

Notes:

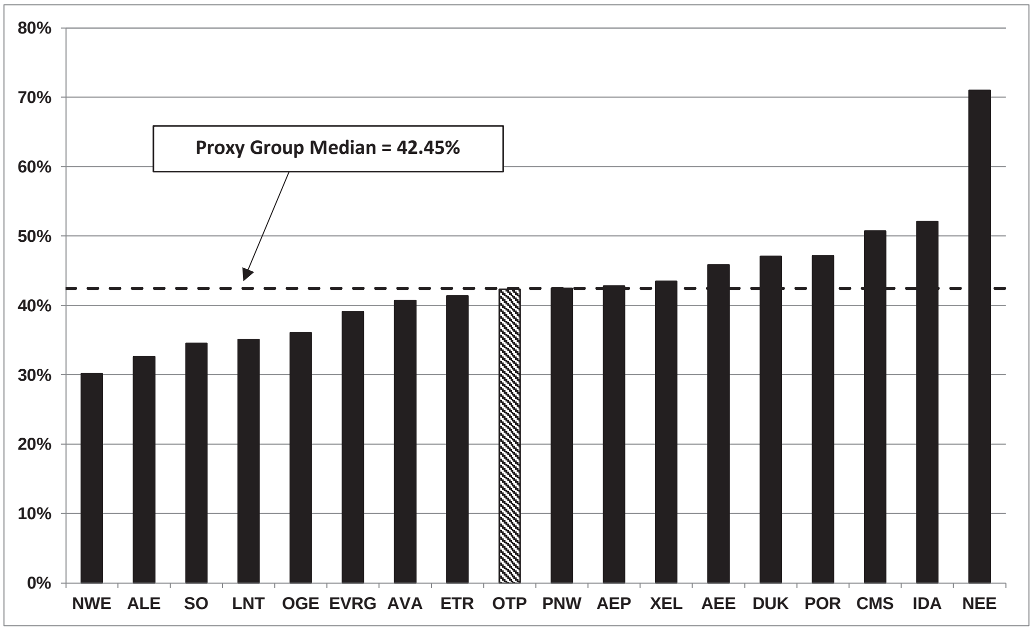
[1] - [5] Source: Value Line, dated May 12, June 9, July 21, 2023.

[6] Equals (Column [2] + [3] + [4] + [5]) / Column [1]

[7] Source: Company Provided Data

[8] Source: Company Provided Data

2024-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT



Projected CAPEX / 2022 Net Plant

Rank	Company		2024-2027
1	NorthWestern Corporation	NWE	30.14%
2	ALLETE, Inc.	ALE	32.60%
3	Southern Company	SO	34.54%
4	Alliant Energy Corporation	LNT	35.06%
5	OGE Energy Corporation	OGE	36.07%
6	Evergy, Inc.	EVRG	39.09%
7	Avista Corporation	AVA	40.70%
8	Entergy Corporation	ETR	41.36%
9	Otter Tail Power Company	OTP	42.33%
10	Pinnacle West Capital Corporation	PNW	42.45%
11	American Electric Power Company	AEP	42.79%
12	Xcel Energy Inc.	XEL	43.46%
13	Ameren Corporation	AEE	45.82%
14	Duke Energy Corporation	DUK	47.04%
15	Portland General Electric Company	POR	47.16%
16	CMS Energy Corporation	CMS	50.70%
17	IDACORP, Inc.	IDA	52.10%
18	NextEra Energy, Inc.	NEE	70.97%
	Proxy Group Median		42.45%
	OTP / Proxy Group		1.00

Notes:
Source: Exhibit___(AEB-1), Schedule 12, pages 1-2 col. [6]

COMPARISON OF OTTER TAIL POWER COMPANY AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]
					Non-Volumetric Rate Design			
Proxy Group Company	**Operating Subsidiary**	**Jurisdiction**	**Service**	**Test Year**	**Revenue Decoupling**	**Formula-based rates**	**Straight Fixed-Variable Rate Design**	**Non-Volumetric Rate Design**
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Fully Forecast	No	No	No	No
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Historical	No	No	No	No
	Interstate Power & Light Co.	Iowa	Gas	Historical	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Historical	Partial	Yes	No	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Partial	No	No	Yes
	Union Electric Co.	Missouri	Electric	Historical	Partial	No	No	Yes
	Union Electric Co.	Missouri	Gas	Historical	Partial	No	No	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Partial	Yes	No	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Full	No	No	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Partial	No	No	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Partial	Yes	No	Yes
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Partial	No	No	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Partial	No	No	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Partial	No	No	Yes
	Kingsport Power Co.	Tennessee	Electric	Fully Forecast	No	No	No	No
	AEP Texas Inc.	Texas	Electric	Historical	No	No	No	No
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No
Avista Corporation	Alaska Electric Light & Power Co.	Alaska	Electric	Historical	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Full	No	No	Yes
	Avista Corp.	Idaho	Gas	Historical	Full	No	No	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes
	Avista Corp.	Washington	Electric	Historical	Full	No	No	Yes
	Avista Corp.	Washington	Gas	Historical	Full	No	No	Yes
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Partial	No	No	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No
	Duke Energy Indiana LLC	Indiana	Electric	Historical	Partial	No	No	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Partial	No	No	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	No	No	No	No
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Full	No	No	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Partial	No	No	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Historical	No	No	No	No
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Partial	No	No	Yes
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Fully Forecast	Partial	No	No	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Partial	Yes	No	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	No	Yes	No	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Partial	Yes	No	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Partial	Yes	No	Yes
	Entergy Texas Inc.	Texas	Electric	Historical	No	No	No	No
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Partial	No	No	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	No	No	No	No
	Evergy Metro Inc	Missouri	Electric	Historical	Partial	No	No	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Partial	No	No	Yes

COMPARISON OF OTTER TAIL POWER COMPANY AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[6]	[7]	[8]	[9]	[10]
				Capital Cost Recovery				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Traditional Generation	Renewables/Non-Traditional Generation	Delivery Infrastructure	Environmental Compliance	Capital Cost Recovery
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	No	Yes	No	No	Yes
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	No	Yes	No	Yes	Yes
	Interstate Power & Light Co.	Iowa	Gas	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	No	Yes	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	No	No	Yes	Yes	Yes
	Union Electric Co.	Missouri	Electric	No	Yes	Yes	No	Yes
	Union Electric Co.	Missouri	Gas	No	No	Yes	No	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Yes	No	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	No	Yes	Yes	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	No	No	Yes	No	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	No	No	No	No	No
	Indiana Michigan Power Co.	Michigan	Electric	No	Yes	No	No	Yes
	Ohio Power Co.	Ohio	Electric	No	Yes	Yes	No	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	No	Yes	Yes	No	Yes
	Kingsport Power Co.	Tennessee	Electric	No	No	No	No	No
	AEP Texas Inc.	Texas	Electric	No	No	Yes	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	No	No	Yes	No	Yes
	Appalachian Power Co.	Virginia	Electric	Yes	No	No	Yes	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	No	No	No	Yes	Yes
Avista Corporation	Alaska Electric Light & Power Co.	Alaska	Electric	No	No	No	No	No
	Avista Corp.	Idaho	Electric	No	No	No	No	No
	Avista Corp.	Idaho	Gas	No	No	No	No	No
	Avista Corp.	Oregon	Gas	No	No	No	No	No
	Avista Corp.	Washington	Electric	No	No	No	No	No
	Avista Corp.	Washington	Gas	No	No	No	No	No
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	No	Yes	No	No	Yes
	Consumers Energy Co.	Michigan	Gas	No	No	No	No	No
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Yes	Yes	No	Yes	Yes
	Duke Energy Indiana LLC	Indiana	Electric	No	Yes	Yes	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	No	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	No	No	Yes	No	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	No	Yes	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	No	No	Yes	No	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	No	Yes	Yes	No	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	No	Yes	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	No	No	Yes	No	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Yes	Yes	Yes	No	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	No	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	No	No	No	No	No
	Entergy Louisiana LLC	Louisiana	Electric	No	No	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	No	No	Yes	No	Yes
	Entergy Mississippi LLC	Mississippi	Electric	No	No	No	No	No
	Entergy Texas Inc.	Texas	Electric	Yes	No	Yes	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	No	Yes	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	No	No	Yes	No	Yes
	Evergy Metro Inc	Missouri	Electric	No	No	Yes	No	Yes
	Evergy Missouri West Inc.	Missouri	Electric	No	Yes	Yes	No	Yes

COMPARISON OF OTTER TAIL POWER COMPANY AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]
					Non-Volumetric Rate Design			
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Test Year	Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Full	No	No	Yes
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	No	No	No	No
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No
OGE Energy Corporation	Oklahoma Gas & Electric Co.	Arkansas	Electric	Historical	Partial	No	Yes	Yes
	Oklahoma Gas & Electric Co.	Oklahoma	Electric	Historical	Partial	No	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Partial	No	No	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Fully Forecast	No	No	No	No
Southern Company	Alabama Power Co.	Alabama	Electric	Historical	No	Yes	No	Yes
	Atlanta Gas Light Co.	Georgia	Electric	Fully Forecast	No	Yes	No	Yes
	Georgia Power Co.	Georgia	Gas	Fully Forecast	No	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Partial	No	No	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Partial	Yes	No	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Partial	Yes	No	Yes
	Virginia Natural Gas Inc.	Virginia	Gas	Historical	Partial	No	No	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Partial	No	No	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Partial	No	No	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Partial	Yes	No	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No
	Southwestern Public Service Co.	New Mexico	Electric	Historical	No	No	No	No
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Partial	No	No	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No

			Non-Volumetric Rate Design	
Proxy Group Average	Fully Forecast	30	Yes	50
	Partially Forecast	7	No	33
	Historical	46		
	Forecast	44.58%	NVRD	60.24%

OTP [11]	Fully Forecasted	No	No	No	No

Notes:
[1] Sources: Regulatory Research Associates, effective as of July 31, 2023
[2] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit
[3] Sources: Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([2]=No, [3]=No, [4]=No), No, Yes)
[6] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[7] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[8] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[9] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[10] Equals IF(AND([6]=No, [7]=No, [8]=No, [9]=No), No, Yes)
[11] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.

COMPARISON OF OTTER TAIL POWER COMPANY AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[6]	[7]	[8]	[9]	[10]
				Capital Cost Recovery				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Traditional Generation	Renewables/Non-Traditional Generation	Delivery Infrastructure	Environmental Compliance	Capital Cost Recovery
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	No	No	No	No	No
	Idaho Power Co.	Oregon	Electric	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Yes	Yes	No	Yes	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	No	No	Yes	Yes	Yes
	Lone Star Transmission LLC	Texas	Electric	No	No	Yes	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	No	No	No	No	No
	NorthWestern Corporation	Montana	Gas	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	No	No	No	No	No
OGE Energy Corporation	Oklahoma Gas & Electric Co.	Arkansas	Electric	No	No	Yes	No	Yes
	Oklahoma Gas & Electric Co.	Oklahoma	Electric	No	No	Yes	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	No	Yes	No	Yes	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Yes	Yes	No	Yes	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Yes	Yes	No	Yes	Yes
	Atlanta Gas Light Co.	Georgia	Electric	No	No	Yes	Yes	Yes
	Georgia Power Co.	Georgia	Gas	Yes	No	No	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	No	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	No	No	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	No	No	No	No	No
	Virginia Natural Gas Inc.	Virginia	Gas	No	No	Yes	No	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	No	Yes	No	No	Yes
	Public Service Co. of Colorado	Colorado	Gas	No	No	Yes	No	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	No	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	No	No	Yes	No	Yes
	Southwestern Public Service Co.	New Mexico	Electric	No	Yes	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	No	Yes	Yes	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	No	No	No	No	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Yes	No	Yes	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	No	No	No	No	No

		CCRM
Proxy Group Average	Yes	56
	No	27
	CCRM	67.47%

	Traditional Generation	Renewables/Non-Traditional Generation	Delivery Infrastructure	Environmental Compliance	Capital Cost Recovery
OTP [11]	Yes	Yes	Yes	Yes	Yes

Notes:
[1] Sources: Regulatory Research Associates, effective as of July 31, 2023
[2] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not cov
[3] Sources: Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([2]=No, [3]=No, [4]=No), No, Yes)
[6] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[7] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[8] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[9] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[10] Equals IF(AND([6]=No, [7]=No, [8]=No, [9]=No), No, Yes)
[11] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.

FLOTATION COST ADJUSTMENT

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Gross Equity Issue Before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
Otter Tail Corporation - Secondary	OTTR	2004-05	3,075.00	25.45	0.95	391.45	24.37	3,312.70	78,258.75	74,946.05	4.23%
Otter Tail Corporation - Secondary	OTTR	2008	5,175.00	30.00	1.09	807.19	28.76	6,435.00	155,250.00	148,815.00	4.14%
Otter Tail Corporation - ESPP	OTTR	2004	66.96	19.31	-	-	19.31	0.00	1,293.00	1,293.00	0.00%
Otter Tail Corporation - ESPP	OTTR	2009	62.45	19.18	-	-	19.18	0.00	1,197.79	1,197.79	0.00%
Otter Tail Corporation - ESPP	OTTR	2014	39.22	26.75	-	-	26.75	0.00	1,049.14	1,049.14	0.00%
Otter Tail Corporation - ESPP	OTTR	2015	42.25	25.93	-	-	25.93	0.00	1,095.54	1,095.54	0.00%
Otter Tail Corporation - ESPP	OTTR	2016	53.88	27.68	-	1.16	27.66	1.16	1,491.40	1,490.24	0.08%
Otter Tail Corporation - ESPP	OTTR	2017	5.28	39.85	-	0.37	39.78	0.37	210.41	210.04	0.17%
Otter Tail Corporation - ESPP	OTTR	2019	15.45	44.3	-	0.84	44.25	0.84	684.44	683.60	0.12%
Otter Tail Corporation - ESPP	OTTR	2020	24.37	35.9	-	1.54	35.84	1.54	874.78	873.24	0.18%
Otter Tail Corporation - DRIP	OTTR	2004	223.17	19.3	-	-	19.30	0.00	4,307.18	4,307.18	0.00%
Otter Tail Corporation - DRIP	OTTR	2009	233.94	19.21	-	5.88	19.18	5.88	4,493.99	4,488.11	0.13%
Otter Tail Corporation - DRIP	OTTR	2014	288.05	26.76	-	-	26.76	0.00	7,708.22	7,708.22	0.00%
Otter Tail Corporation - DRIP	OTTR	2015	330.38	25.93	-	56.55	25.76	56.55	8,566.75	8,510.20	0.66%
Otter Tail Corporation - DRIP	OTTR	2016	302.52	36.68	-	32.97	36.57	32.97	11,096.43	11,063.46	0.30%
Otter Tail Corporation - DRIP	OTTR	2017	107.29	38.58	-	17.55	38.42	17.55	4,139.25	4,121.70	0.42%
Otter Tail Corporation - DRIP	OTTR	2019	51.35	49.58	-	7.13	49.44	7.13	2,545.93	2,538.80	0.28%
Otter Tail Corporation - DRIP	OTTR	2020	190.68	42.03	-	20.93	41.92	20.93	8,014.92	7,993.99	0.26%
Otter Tail Corporation - ATM	OTTR	2014	519.64	29.51	0.59	780.62	27.42	1,087.36	15,334.58	14,247.21	7.09%
Otter Tail Corporation - ATM	OTTR	2015	133.20	28.42	0.42	339.16	25.45	395.65	3,785.54	3,389.89	10.45%
Otter Tail Corporation - ATM	OTTR	2016	1,014.12	32.77	-	561.55	32.22	561.55	33,235.73	32,674.18	1.69%
Otter Tail Corporation - ATM	OTTR	2019	372.00	50.96	1.55	237.22	48.77	814.35	18,957.30	18,142.95	4.30%
Otter Tail Corporation - ATM	OTTR	2020	843.48	42.89	-	452.23	42.36	452.23	36,178.36	35,726.13	1.25%
Total								$ 13,203.76	$ 399,769.43	$ 386,565.67	
								WEIGHTED AVERAGE FLOTATION COSTS			3.30%

[i] Offering Completion Date
[ii] Underwriting discount is 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 1.0000, 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:

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

		[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	Cost of Equity: Mean Growth Rate	Cost of Equity Adjusted for Flotation Costs
ALLETE, Inc.	ALE	$2.71	$58.12	4.66%	4.84%	5.00%	6.00%	8.10%	8.10%	7.40%	12.24%	12.40%
Alliant Energy Corporation	LNT	$1.81	$53.11	3.41%	3.52%	3.64%	6.50%	7.00%	6.50%	6.67%	10.19%	10.31%
Ameren Corporation	AEE	$2.52	$84.17	2.99%	3.09%	3.19%	6.50%	5.90%	6.40%	6.27%	9.35%	9.46%
American Electric Power Company, Inc.	AEP	$3.32	$85.37	3.89%	4.00%	4.13%	6.00%	5.20%	5.60%	5.60%	9.60%	9.73%
Avista Corporation	AVA	$1.84	$38.97	4.72%	4.87%	5.04%	6.50%	6.30%	6.30%	6.37%	11.24%	11.40%
CMS Energy Corporation	CMS	$1.95	$59.91	3.25%	3.37%	3.49%	6.50%	7.80%	7.80%	7.37%	10.74%	10.86%
Duke Energy Corporation	DUK	$4.02	$91.84	4.38%	4.50%	4.65%	5.00%	5.74%	6.10%	5.61%	10.11%	10.27%
Entergy Corporation	ETR	$4.28	$99.98	4.28%	4.37%	4.52%	0.50%	6.60%	5.70%	4.27%	8.64%	8.79%
Evergy, Inc.	EVRG	$2.45	$59.41	4.12%	4.23%	4.37%	7.50%	2.67%	5.20%	5.12%	9.35%	9.50%
IDACORP, Inc.	IDA	$3.16	$102.78	3.07%	3.14%	3.25%	5.00%	3.70%	3.70%	4.13%	7.27%	7.38%
NextEra Energy, Inc.	NEE	$1.87	$73.81	2.53%	2.65%	2.74%	9.50%	8.80%	8.40%	8.90%	11.55%	11.64%
NorthWestern Corporation	NWE	$2.56	$57.12	4.48%	4.58%	4.74%	3.50%	4.50%	5.20%	4.40%	8.98%	9.14%
OGE Energy Corporation	OGE	$1.66	$35.97	4.60%	4.72%	4.88%	6.50%	negative	3.70%	5.10%	9.82%	9.98%
Pinnacle West Capital Corporation	PNW	$3.46	$81.98	4.22%	4.33%	4.47%	2.50%	6.10%	6.30%	4.97%	9.29%	9.44%
Portland General Electric Company	POR	$1.90	$47.35	4.01%	4.13%	4.27%	5.00%	5.90%	6.00%	5.63%	9.76%	9.90%
Southern Company	SO	$2.80	$71.21	3.93%	4.05%	4.19%	6.50%	7.30%	4.00%	5.93%	9.98%	10.12%
Xcel Energy Inc.	XEL	$2.08	$63.31	3.29%	3.39%	3.50%	6.00%	6.15%	6.30%	6.15%	9.54%	9.65%
Mean											9.86%	10.00%
Median											9.76%	9.90%
Flotation Cost Adjustment (Mean)												0.14%
Flotation Cost Adjustment (Median)												0.14%

Notes:
[1] - [5] Source: Company-provided information
[6] Equals [9]/[2]
[7] Equals [5] + ([4] x [2])
[8] Equals [2] x [3]
[9] Equals [8] - [7]
[10] Equals [7] / [8]
[11] Bloomberg Professional
[12] Bloomberg Professional, equals 30-day average as of July 31, 2023
[13] Equals [11] / [12]
[14] Equals [13] x (1 + 0.5 x [19])
[15] Equals [14] / (1 − Flotation Cost)
[16] Value Line
[17] Yahoo! Finance
[18] Zacks Investment Research
[19] Equals Average of [16], [17], [18]
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals [21] (Mean) − [20] (Mean)
[23] Equals [21] (Median) − [20] (Median)

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2021Q3 - 2023Q2)				
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-Term Debt Ratio	Total Capitalization
ALLETE, Inc.	ALE	58.57%	41.35%	0.00%	0.08%	100%
Alliant Energy Corporation	LNT	51.57%	47.23%	0.19%	1.01%	100%
Ameren Corporation	AEE	52.18%	45.41%	0.56%	1.85%	100%
American Electric Power Company, Inc.	AEP	46.98%	51.11%	0.00%	1.91%	100%
Avista Corporation	AVA	47.50%	48.00%	0.00%	4.50%	100%
CMS Energy Corporation	CMS	51.32%	47.96%	0.19%	0.53%	100%
Duke Energy Corporation	DUK	51.78%	46.30%	0.00%	1.92%	100%
Entergy Corporation	ETR	47.30%	52.59%	0.10%	0.00%	100%
Evergy, Inc.	EVRG	57.55%	36.65%	0.00%	5.79%	100%
IDACORP, Inc.	IDA	53.66%	46.33%	0.00%	0.00%	100%
NextEra Energy, Inc.	NEE	60.41%	38.16%	0.00%	1.43%	100%
NorthWestern Corporation	NWE	49.29%	50.71%	0.00%	0.00%	100%
OGE Energy Corporation	OGE	53.40%	45.52%	0.00%	1.09%	100%
Pinnacle West Capital Corporation	PNW	49.76%	47.83%	0.00%	2.41%	100%
Portland General Electric Company	POR	45.30%	54.23%	0.00%	0.46%	100%
Southern Company	SO	54.52%	43.38%	0.23%	1.87%	100%
Xcel Energy Inc.	XEL	54.00%	45.20%	0.00%	0.80%	100%
Average		52.06%	46.35%	0.08%	1.51%	
Median		51.78%	46.33%	0.00%	1.09%	
Maximum		60.41%	54.23%	0.56%	5.79%	
Minimum		45.30%	36.65%	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] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

Volume 2B

Direct Testimony and Supporting Schedules:

Peter E. Wasberg

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

EMPLOYEE COMPENSATION AND BENEFITS

Direct Testimony and Schedules of

PETER E. WASBERG

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My Name is Peter E. Wasberg. I am employed by Otter Tail Power Company (OTP).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Director of Human Resources and Safety. I am responsible for leading the Company's human resources and safety functions, including compensation and benefits, labor relations, employee relations, organizational development, compliance, and training.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit ___ (PEW-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to discuss matters related to employee compensation and benefits. First, I will briefly describe OTP's current compensation plan, including its annual incentive plans. Second, I will discuss how the compensation levels provided by OTP compare to the general market. Third, I will describe the employee benefits provided by OTP. Fourth, I will summarize certain 2024 Test Year compensation and benefit costs. OTP witnesses Mr. Bruce G. Gerhardson and Ms. Christy L. Petersen discuss 2024 Test Year pension and postretirement medical and life insurance (PRM) plan expenses in their respective Direct Testimony.[1]

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. Section III describes OTP's workforce and compensation plan. Section IV describes OTP compensation levels and the competitive market. Section V

[1] Pension plan costs formerly were accounted for under FAS 87, while PRM costs were subject to FAS 106. A third category of costs, Postemployment (LTD) Medical Benefit Plan costs, are now subject to ASC 712 and formerly were subject to FAS 112.

describes OTP's employee benefits. Section VI describes certain 2024 Test Year employee costs, and Section VII provides my conclusions.

Q. HOW HAVE YOU LABELED DOLLAR VALUES IN YOUR DIRECT TESTIMONY AND SUPPORTING SCHEDULES?

A. Throughout my testimony and schedules, I label dollar values as "(OTP ND)" when the values are jurisdictionalized to North Dakota. I label total company costs as "(OTP Total)." Some costs fall into numerous functions, each with its own jurisdictional allocation, and therefore a straightforward calculation of a jurisdictional amount based on a single allocator is not possible (e.g., labor cost categories, which may include costs functionalized as generation, transmission, distribution, administration, and general, with each function having its own unique jurisdictional allocation). For costs like this, I have estimated the North Dakota jurisdictional dollar values by multiplying the total company costs by a single blended allocator. I have labeled these values as "(OTP ND EST)."

III. OVERVIEW OF OTP'S WORKFORCE AND COMPENSATION PLAN

Q. PLEASE BRIEFLY DESCRIBE OTP'S WORK FORCE.

A. In 2024, OTP expects to have an average of 800 full time equivalent (FTE) employees, including approximately 376 union employees and 424 non-union employees (not adjusted for employees of jointly owned power plants). The non-union FTE employees include nine executives, 282 exempt employees, and 133 non-exempt employees. OTP employees provide a wide range of services required to supply electric utility services to our customers located in North Dakota, South Dakota, and Minnesota.

Q. WHAT ARE OTP'S COMPENSATION GOALS FOR ITS WORKFORCE?

A. OTP's compensation goals are to attract, retain, and engage employees. OTP's employees are essential to achieve OTP's mission, which is to produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees, and to improve the quality of life in the areas in which we do business. OTP focuses on maintaining a compensation program that provides a competitive, performance-based pay system that helps us attract and retain a quality workforce that provides our customers with safe, reliable, and economical service. Attracting and retaining employees has become more challenging in recent years.

Q. PLEASE EXPLAIN THE RECENT CHALLENGES IN ATTRACTING AND RETAINING EMPLOYEES.

A. Between 2014 and 2020, we experienced an average of 20 non-retirement attritions per year, with a low of 15 and a high of 27. These attrition rates have changed significantly following the COVID-19 pandemic: in 2021, we had 32 non-retirement attritions; in 2022, that number increased to 42 in 2022. Through September 2023, we have had 26 non-retirement attritions, with three months remaining in the year. Many businesses are seeing similar attrition issues.

There also are more job opportunities than available workers in the current labor market. These conditions create many challenges in our industry, where on-the-job experience is so critical. For example, we have several positions that are structured as multi-year apprenticeships. Retaining experienced and talented employees is vital given the well-known priority employees, customers and the public place on safety in our industry. As we see pressure on wages, and changing demographics in our region, with less people entering the workforce compared to those exiting the workforce, we will need to find new ways to attract and retain the talent needed to safely and efficiently operate our business, providing electricity to our customers across our service territory.

Q. ARE THERE OTHER REASONS THAT OTP NEEDS TO HAVE A COMPENSATION PLAN THAT ATTRACTS, RETAINS AND ENGAGES EMPLOYEES?

A. Yes. As noted above, our high-quality workforce is essential to providing customers with safe, reliable, and economical service. Like many companies, we are experiencing some generational attrition, with over 30 percent (over 250) of our employees expected to retire during the next ten years. We also have the potential for another 250 – 360 employees to leave employment during this same ten-year period based on historic, non-retirement attrition, which, as discussed above, has increased significantly over the past three years. All of this means we will need to hire many high-quality individuals over the next several years, while at the same time doing what is necessary to retain the talent needed to effectively serve our customers. As a relatively small utility serving the rural areas of North Dakota, South Dakota, and Minnesota, OTP faces challenges in attracting and retaining skilled workers, especially with more mobile workers who are in the earlier stages of their careers.

Q. WHAT ARE THE MAIN COMPONENTS OF OTP'S COMPENSATION PLAN?

A. The OTP compensation plan consists of: (1) cash compensation based on a combination of base salaries or base wages, plus annual incentive compensation for non-union employees; (2) standard employee benefit plans, including health and dental plans, a 401(k) retirement savings plan with an employer match, and an employee stock ownership plan; (3) defined benefit pensions and post-retirement health benefits for employees whose employment began before OTP closed participation in these plans starting in 2006 (as I describe later in my Direct Testimony); and (4) defined contributions to a 401(k) plan for other employees. Some key OTP management employees also are eligible for long-term incentives.

Q. PLEASE BRIEFLY DESCRIBE THE BASE SALARY AND WAGE COMPONENT OF OTP'S COMPENSATION PLAN.

A. OTP has a combination of hourly and salaried employees. Approximately 50 percent of OTP's employees are represented by unions. OTP has approximately 50 percent salaried (approximately 35 percent exempt and 15 percent nonexempt) employees who are not part of executive management. All employees receive either a base wage or base salary as part of the employee's cash compensation.

Q. PLEASE BRIEFLY DESCRIBE THE OTP ANNUAL INCENTIVE PLAN.

A. The OTP Annual Incentive Plan is provided to all regular employees who are not represented by a union and who work at least 1,000 hours per year. The OTP Annual Incentive Plan consists of four separate plans: (1) non-union employees (the OTP Key Performance Award Plan or OTP KPA Plan); (2) non-union people leaders who are not eligible for other plans (the People Leaders Plan); (3) Coyote Retention Inventive Plan for non-union staff at Coyote Station (the Coyote Retention Incentive Plan); and (4) key management employees (the OTP Management Plan).

Q. PLEASE BRIEFLY DESCRIBE THE OTP KPA PLAN.

A. The OTP KPA Plan covers approximately 400 OTP non-union employees. The OTP KPA Plan is based on: (1) four operating criteria (safety, a customer satisfaction indicator, reliability based on the average outage minutes per customer, and equivalent plant availability); and (2) one financial criterion relating to the control of operation and maintenance (O&M) costs. Each of these five criteria has a weighting that together comprise the six percent maximum payout. The maximum payout level is six percent of an individual employee's base salary. As part of the OTP KPA – People Leaders plan, people leaders can earn up to an additional three percent, above whatever the earned KPA payment is for that year, based on their performance as managers/supervisors.

Q. PLEASE EXPLAIN THE WEIGHTING OF THE FIVE INDIVIDUAL CRITERIA.

A. Customer satisfaction, reliability, and equivalent plant availability each have a weighting of one percent; safety has two targets, each worth 0.5 percent. The O&M cost control criteria has a weighting of up to two percent. Payouts under the operating criteria are not financially tied to the O&M cost control criterion.

Q. PLEASE BRIEFLY DESCRIBE THE PEOPLE LEADERS PLAN.

A. Based on external market data, along with the need to be able to attract and retain talented people who can help serve our customers, OTP has added an additional plan, specific to people leaders (managers/supervisors) that do not otherwise qualify for any incentives beyond the current KPA Plan. Market data showed OTP below market on short-term incentive compensation, and as we have been challenged with higher attrition rates, we added a plan that will incentivize people leaders. The additional incentive, up to 3 percent above the current KPA Plan, will recognize good leadership, with the objective to recognize the leadership that will help meet our key performance objectives that are positively impacting the service we provide to our customers. The incentive also recognizes market conditions where OTP has been below market with short-term compensation, with the expectation that it provides another way to help attract and retain quality people leaders.

Q. PLEASE BRIEFLY DESCRIBE THE COYOTE RETENTION INCENTIVE PLAN.

A. With the uncertainty brought about by current and proposed federal regulations that could potentially impact some generation facilities, we added a plan specific to non-union employees at Coyote Station. The plan objectives are to focus participants' attention on our operating results, ensuring that we can continue to achieve desired outcomes. With the current uncertainty for some power plants, and with the need to continue operations safely and efficiently at Coyote Station, we are recognizing good performance for those non-union employees who are choosing to remain employees at Coyote Station.

Q. PLEASE BRIEFLY DESCRIBE THE OTP MANAGEMENT PLAN.

A. The OTP Management Plan covers 24 OTP management employees (not including the OTP President, who has a separate plan). The OTP Management Plan includes: (1) safety; (2) a number of criteria that vary by the employee's job and responsibilities; and (3) two overall financial criteria relating to OTP. The safety and individual criteria have a cumulative weighting of 50 percent. The financial criteria have a weighting of 50 percent.

Q. PLEASE DESCRIBE THE INCENTIVE PLAN FOR THE OTP PRESIDENT.

A. The OTP President is under the Otter Tail Corporation Executive Annual Incentive Plan (Executive Plan). Under the Executive Plan, the Compensation and Human Capital Management Committee of the Otter Tail Corporation Board of Directors determines the criteria and target incentives. Criteria under the Executive Plan include: (1) OTP net income; (2) OTP return on equity; (3) Otter Tail Corporation earnings per share; (4) individual performance; (5) Occupational Safety and Health Administration (OSHA) safety case rate; (6) diversity, equity and inclusion (DEI); and (7) environmental. The financial criteria have a weighting of 70 percent. The safety and individual criteria have a cumulative weighting of 30 percent. The DEI and environmental criteria are evaluated after the annual incentive payout is calculated (based on measures 1-5) and can add up to 5 percent of the target annual incentive to the payout, respectively.

Q. DO THE FINANCIAL CRITERIA OF OTP'S ANNUAL INCENTIVE PLANS PROVIDE BENEFITS TO CUSTOMERS?

A. Yes. The financial performance components of the individual plans that make up the Annual Incentive Plan benefit customers because financial performance depends on the prudent management of costs, which allows OTP to provide electric utility service at reasonable prices. Combining financial criteria, along with performance measures, ensures that we maintain the balance between reliable service and reasonable prices. This balance and the financial criteria that support this balance benefit our customers. For example, in 2022, as described by Mr. Gerhardson, OTP continues to perform well, with very low rates for its customers.

Q. HOW DOES THE OTP ANNUAL INCENTIVE PLAN FIT INTO OTP'S TOTAL COMPENSATION PLAN AND COMPENSATION GOALS?

A. The OTP Annual Incentive Plan is needed to maintain an appropriate level of cash compensation required to attract and retain employees. Without our Annual Incentive Plan, OTP's total cash compensation would be significantly below the market median of total cash compensation, and OTP would be impeded in its ability to attract and retain essential employees. The annual cash incentive compensation that is part of the OTP Annual Incentive Plan also encourages increased productivity and enables OTP to reward employees for providing quality service to our customers. Customers benefit from setting employee incentives that tie directly to our customers' needs.

Q. DOES THE OTP ANNUAL INCENTIVE PLAN AFFECT WORKFORCE CONTINUITY?

A. Yes. The OTP Annual Incentive Plan also helps us address workforce continuity. Our electrical plants and electrical systems perform better when we have continuity in our workforce. The technical knowledge needed, and the years required to acquire the specialized skills for our system, are paramount to our ability to reliably and efficiently provide energy to our customers. Our customers also see the advantages of reduced costs associated with the lower recruitment and training requirements associated with a stable workforce. With an expected retirement rate of over 30 percent in the next ten years and higher non-retirement attrition following the COVID-19 pandemic, maintaining a competitive compensation package is critical to our ability to keep our high-quality employees engaged and providing safe and reliable service to customers.

Q. IS THERE AN ALTERNATIVE TO USING THE OTP ANNUAL INCENTIVE PLAN TO PROVIDE A COMPETITIVE CASH COMPONENT IN OTP'S COMPENSATION PACKAGE?

A. The only way to maintain a competitive cash compensation level without the OTP Annual Incentive Plan would be to increase base salaries, which would increase other costs and substantially reduce both flexibility and incentives for performance.

Q. DOES OTP PROVIDE ANY SHORT-TERM INCENTIVES TO EMPLOYEES?

A. Yes. From time to time, OTP grants Achievement Awards: a cash award intended to recognize and reward employees who have performed exceptionally well on special projects or challenging work outside of normal assignments. Achievement Awards are modest.

Q. DOES OTP PROVIDE LONG-TERM INCENTIVES?

A. Yes. Qualifying management employees may receive long-term incentives in the form of grants of restricted stock units (RSUs). Qualifying employees are awarded RSUs based on salary, job level, and the price of the stock at the date of grant. These long-term incentives are considered along with other components of compensation when we review compensation levels. The purposes of OTP's long-term incentives are to: (1) link the long-term success of OTP to qualifying employee compensation; (2) encourage the retention of management over the long-term; and (3) provide the opportunity to earn competitive total compensation.

IV. OTP COMPENSATION LEVELS AND THE COMPETITIVE MARKET

Q. HOW DO OTP'S COMPENSATION LEVELS COMPARE TO OTHER UTILITIES?

A. OTP's compensation levels generally are at the market mid-point for non-executive employees. Executive compensation levels are lower than the market. I will explain how OTP compensation levels compare to other utilities in this section of my Direct Testimony.

Q. DOES OTP USE MARKET SURVEY INFORMATION IN CONNECTION WITH ITS COMPENSATION DECISIONS?

A. Yes. OTP routinely uses market survey information to compare its compensation levels to those of other utilities and some non-utilities, using numerous surveys and information sources including Willis Towers Watson (WTW), Mercer, Silverstone, and Aon Hewitt (Hewitt). OTP regularly participates in a benchmark study for non-executive employees, the most recent of which was conducted by Mercer. We also periodically participate in studies of executive compensation, which I will discuss later in my Direct Testimony.

Q. HOW DOES OTP USE BENCHMARK STUDIES?

A. OTP uses benchmark studies as the framework for formulating its compensation programs. Salary surveys are reviewed and analyzed to find positions that correspond with the essential job duties, skills, and functions of OTP's positions. OTP strives to set compensation at or near the median of the survey data. While the market-based compensation for a position is based on the median, it is not limited to the single data point of the median. Rather, the relevant market for a position includes a range above and below the median. The compensation for OTP non-union employees is ultimately determined by a combination of market data and the employee's responsibilities, performance, and experience.

Q. PLEASE FURTHER EXPLAIN THE MOST RECENT BENCHMARK STUDY PERFORMED BY MERCER.

A. Mercer's 2022 Compensation Competitiveness Study covered non-executive employees and included compensation information for a broad sample of positions. The Mercer 2022 Compensation Competitiveness Study examined base salaries and annual incentives. OTP compensation levels were compared using a combination of: (1) general industry; (2) energy/utility industry; and (3) North Central regional data to reflect the labor markets in which OTP competes for employees. The Mercer 2022 Compensation Competitiveness Study is provided as Exhibit___(PEW-1), Schedule 2.

Q. WHAT DID THE MERCER 2022 COMPENSATION COMPETITIVENESS STUDY INDICATE?

A. The Mercer 2022 Compensation Competitiveness Study showed that:

1. OTP base salaries overall are at market, based on the 50th percentile;
2. OTP total cash compensation (base and short-term incentive) was one percent below the market median; and
3. Of the 200 non-union positions, representing 302 employees, that were reviewed, some fell below the market median, and some were above the market median.

Q. WHAT DID YOU CONCLUDE FROM THESE RESULTS?

A. The Mercer 2022 Compensation Competitiveness Study showed that, overall, the OTP compensation plan is competitive with the market and reasonable, especially considering the average tenure of our employee group. It also indicated that our compensation structure included in our rate request for non-executive employees is fair and reasonable.

Q. HAS MERCER CONDUCTED A RECENT STUDY OF EXECUTIVE COMPENSATION FOR OTP?

A. Yes. Mercer conducted an Executive Benchmarking study (the Mercer 2022 Executive Benchmarking Study) that evaluated a number of compensation components, including: (1) base salary; (2) total cash compensation; and (3) total direct compensation (including base salary, annual incentive compensation, and long-term incentive). The Mercer 2022 Executive Benchmarking Study utilized multiple data points including: (1) Mercer 2022 US Executive Remuneration Suite; (2) the Towers Watson 2022 CDB Energy Services Executive Compensation Survey; and (3) the Mercer 2022 Total Compensation for the Energy Sector Survey. Mercer utilized information from the energy and utility industry sectors where possible and applied discounts and premiums when the survey data reflected companies that were significantly larger or smaller than OTP. A copy of the Mercer 2022 Executive Benchmarking Study is provided as Exhibit___(PEW-1), Schedule 3.

Q. WHAT DID THE MERCER 2022 EXECUTIVE BENCHMARKING STUDY SHOW?

A. The Mercer 2022 Executive Benchmarking Study showed the following:

1. OTP executive base salaries were five percent below the market median, and
2. OTP's actual total executive cash compensation was four percent below the market median.

Q. WHAT DID YOU CONCLUDE FROM THESE RESULTS?

A. I concluded that OTP's executive compensation is below the market median, but within the competitive range (+/- 10 percent).

V. EMPLOYEE BENEFITS

Q. PLEASE SUMMARIZE THE BENEFITS PROVIDED BY OTP.

A. As I will explain in more detail, OTP provides: (1) employee medical/dental benefits; (2) retirement benefits, including a defined benefit pension plan and defined contribution 401(k) plans; and (3) other post-retirement employee benefits.

Q. ARE THE BENEFITS PROVIDED BY OTP A REASONABLE PART OF EMPLOYEE COMPENSATION?

A. Yes. OTP's benefits contribute to attracting and retaining its skilled workforce. As discussed above, OTP and its customers are directly benefited by having a stable, long-term workforce. In an industry where multiple years of training are required for employees to work independently, it is fiscally prudent to have a workforce with as low a turnover rate as possible. As we retire over 30 percent of our workforce within the next ten years, it will be increasingly important for OTP to attract and retain a workforce that will continue to provide electricity to our customers in a safe, reliable, and efficient manner.

A. Medical and Dental

Q. PLEASE DESCRIBE OTP'S MEDICAL AND DENTAL BENEFITS.

A. OTP provides qualifying employees with the ability to elect group medical and dental insurance benefits. At present, we have three high deductible health plans (HDHP) and one additional consumer-driven plan for our non-union employees and a separate single HDHP option for our union employees. A summary of the health care plans is provided in Table 1 below.

Table 1

2024 Medical Plans					
	Nonunion Employees				Union Employees
	Premier 80 Non-Embedded	Advantage 70 Embedded	Basic 100 Embedded	Surest	Blue Saver 100 Embedded
Annual Deductible	$2,000 – Individual $4,000 – Other Tiers	$4,000 – Individual $8,000 – Other Tiers	$7,000 – Individual $14,000 – Other Tiers	$0 – Individual $0 – Other Tiers	$3,200 – Individual $6,400 – Other Tiers
Co-Insurance	80% after deductible	70% after deductible	100% after deductible	No coinsurance $35-$135 copays per primary care or specialist	NA
Annual Out of Pocket Max	$4,000 – Individual $8,000 – Other Tiers	$6,000 – Individual $12,000 – Other Tiers	$7,000 – Individual $14,000 – Other Tiers	$5,500 – Individual $11,000 – Other Tiers	$3,200 – Individual $6,400 – Other Tiers

Premiums for the medical and dental plans vary based on: (1) the plan(s) chosen; (2) whether dependents are covered; and (3) differences between current non-union and union plans that will be further described, below.

Q. PLEASE SUMMARIZE STEPS OTP HAS TAKEN REGARDING HDHP PLANS.

A. In 2012, OTP moved to a HDHP for all employees. The move to the HDHP, sometimes called a consumer-driven health plan, has enabled our employees to be better health care consumers. In 2017, we took a further step with our non-union employees and replaced the existing HDHP with three new HDHP options that included different deductibles, premiums, and these plan options also introduced coinsurance. Coinsurance keeps employees in the decision-making process longer and generally provides for increased consumerism. Although health care costs continue to be a challenge, we believe our actions have enabled our employees to be better consumers, and we expect that our emphasis on preventive health care and wellness will provide long-term benefits for our employees and for Company health care costs.

Q. HAS OTP TAKEN OTHER STEPS TO CONTROL THE COST OF MEDICAL AND DENTAL BENEFITS?

A. Yes. In 2017, OTP increased the cost-sharing ratio of employee to employer share of the health care premium. The employer share/employee share for gross health costs, which includes total spend for both OTP and employees, moved from approximately 80 percent employer/20 percent employee to 75 percent employer/25 percent employee on all three of the HDHPs.

With our changes for non-union employees in 2017, OTP also added a monthly tobacco surcharge of $40 and we eliminated health care eligibility for spouses who were able to obtain health care insurance from their own employer. The latter has created considerable issues for some employees, and we will be removing the spousal exclusion in 2024. In 2021, we added the $40 tobacco surcharge for our Coyote Union group. In our 2023 labor negotiations, we increased premiums in the first year of the three-year contract, along with five percent increases for years two and three. Some of these changes are difficult for our employees and we will continue working on providing quality health care options for our employees while being responsible with the overall costs associated with the benefit. We know that healthcare is a critical benefit for employees, and that it has an impact as current employees weigh other options, and as we recruit future employees.

B. Retirement Savings and Pension

Q. PLEASE SUMMARIZE OTP'S RETIREMENT SAVINGS AND PENSION BENEFITS.

A. OTP provides 401(k) defined contribution retirement plans (401(k) Plans) for all employees and defined benefit pension plans (Pension Plan) for certain employees depending on the date they were hired. OTP also provides a 401(k) matching plan.

Q. PLEASE DESCRIBE OTP'S 401K PLAN.

A. For employees who are not eligible to participate in OTP's Pension Plan, as of 2024, OTP has 401(k) Plans that include three different defined contribution amounts made by OTP: (1) a five percent contribution for non-union employees; (2) a seven percent contribution for our Coyote Station union employees; and (3) a five percent contribution for our other union employees. A summary description of OTP's 401(k) Plans is included in Exhibit___(PEW-1), Schedule 4a.

Q. DOES OTP MATCH EMPLOYEE CONTRIBUTIONS TO THE 401(K) PLANS?

A. Yes. All OTP employees are eligible for some form of match based on their individual contributions to the 401(k) Plans.

Q. ARE EMPLOYEES ELIGIBLE FOR OTP'S PENSION PLAN ALSO ELIGIBLE TO PARTICIPATE IN THE MATCHING PORTION OF OTP'S 401(K) PLANS?

A. Yes. Pension Plan-eligible employees may make contributions to OTP's 401(k) Plans, and we strongly encourage them to do so, but they do not receive OTP enhanced contributions. Rather, they are eligible to receive the OTP employer match subject to the maximum matching provisions as noted in Exhibit___(PEW-1), Schedule 4a.

Q. WHAT 401(K) MATCH IS AVAILABLE TO OTP EMPLOYEES WHO ARE NOT PENSION ELIGIBLE?

A. Non-union employees, and bargaining unit employees (other than Coyote Station union employees), are eligible for a match of fifty percent of their first eight percent individually contributed (maximum of 4 percent). Coyote bargaining unit employees are eligible for a match of fifty percent of their first six percent individually contributed (maximum of 3 percent).

Q. PLEASE DESCRIBE OTP'S PENSION PLAN.

A. OTP's Pension Plan has two benefit formulas: (1) a benefit formula for non-union and union employees, other than Coyote Station union employees; and (2) a separate benefit formula for union employees at Coyote Station. A summary description of OTP's Pension Plan is provided in Exhibit___(PEW-1), Schedule 4b. An overall retirement benefits eligibility summary is provided in Exhibit___(PEW-1), Schedule 4c.

Q. DOES OTP HAVE ANY OTHER RETIREMENT PLANS?

A. Yes. Key management employees participate in an Executive Restoration Plus Plan (ERPP), an unfunded, non-qualified benefit plan that provides defined contribution payments to these employees. OTP also maintains an Executive Survivor & Supplemental Retirement Plan (ESSRP).

Q. WHY DOES OTP PROVIDE AN ERPP PLAN?

A. The ERPP provides a benefit based on total pay, including incentive compensation, in recognition of the fact that more executive compensation is tied to performance that can fluctuate year-over-year (at risk). Earned incentive compensation is not calculated as part of a retirement benefit for non-union employees. The ERPP provides a method to recognize at-risk pay, when earned, as part of total compensation for calculating retirement benefits.

Q. PLEASE DESCRIBE THE ESSRP.

A. The ESSRP is a defined benefit plan that was adopted in 1983 to provide key executives and management employees competitive survivor and retirement benefits. In the early 1980s, certain tax law limitations reduced the amount of pension-related retirement benefits that could be received by key executives and management employees. The ESSRP was designed as a Supplemental Executive Retirement Plan. It was transitioned to a restoration benefit used to restore the pension-related retirement benefits of impacted employees to the same baseline (percentage) level of OTP's overall pension plan.

Q. ARE PARTICIPANTS BEING ADDED TO THE ESSRP?

A. No. The last participant was added January 1, 2009, and from that time forward, there have been no new participants in the ESSRP. In 2019, the restoration retirement benefit component for participants was frozen, meaning no new benefits were being earned within the ESSRP.

C. Other Post Retirement Employee Benefits

Q. DOES OTP PROVIDE OTHER POST-RETIREMENT EMPLOYEE BENEFITS?

A. Yes. OTP also provides other post-retirement benefits (OPEBs) including: (1) the PRM Plan; (2) Postemployment (LTD) Medical Benefit Plan for a limited number of disabled employees; and (3) life insurance for a limited number of eligible retirees.

Q. PLEASE DESCRIBE ELIGIBILITY FOR THE LIFE INSURANCE BENEFIT.

A. The life insurance benefit is no longer available to new employees as a company-paid expense. Eligibility is restricted to those employees who had 25 years of service with OTP as of January 1, 2003, and to Coyote Union employees who were employees at the time OTP took over the operations of Coyote Station in 1998.

D. Management of Pension and OPEB Costs

Q. HAS OTP PREVIOUSLY TAKEN STEPS TO MANAGE THE COST OF ITS PENSIONS AND OPEBS?

A. Yes. Since 2006, OTP has made significant changes to retirement benefits to control costs. The first significant change eliminated eligibility to participate in the OTP Pension Plan for employees hired after certain dates. This change is sometimes referred to as a “soft freeze.” The effective dates of the soft freeze differ depending on bargaining-unit status. For non-union employees, the soft freeze eliminated participation in the OTP Pension Plan for employees hired after August 31, 2006. For the Coyote Plant bargaining-unit employees, the soft freeze eliminated participation in the OTP Pension Plan for employees hired after December 31, 2008. For our other bargaining-units, the soft freeze eliminated participation in the OTP Pension plan for employees hired after October 31, 2013. Employees not eligible for the OTP Pension Plan are eligible to receive the OTP contributions to their 401(k) Plan I described earlier in my testimony.

The second significant change was the elimination of post-retirement medical benefits for new employees. Like the soft freeze on the OTP Pension Plan, this change means that employees hired after certain dates are not eligible for post-retirement medical benefits. Also like the soft freeze on the OTP Pension Plan, the effective dates differed based on bargaining unit status. For our non-union employees, this soft freeze was effective for employees hired after August 31, 2006. For the Coyote Plant bargaining unit, this soft freeze was effective for employees hired after December 31, 2008. For our other bargaining-units, this soft freeze was effective for employees hired after October 31, 2010. For all these groups, participation also is limited to persons who are age 55 or older at retirement with 10 or more years of service and eligible for or enrolled in the OTP medical program as of retirement.

Q. WHAT EFFECT HAS THE SOFT FREEZE HAD ON THE OTP PENSION PLAN?

A. The soft freeze, in combination with retirements, is significantly reducing the number of OTP employees participating in the OTP Pension Plan. As a result of the soft freeze on the OTP Pension Plan, we now have approximately 60 percent of our active employees who are not participating in the OTP Pension Plan (up from 30 percent at the time of our last North Dakota rate case) and we would expect that percentage to increase significantly with the number of retirements expected over the next ten years.

Q. HAS OTP RECENTLY CONTINUED TO TAKE STEPS TO MANAGE THE COST OF ITS PRM PLAN?

A. Yes. Beginning in 2020, OTP began the process of moving from the Retiree Drug Subsidy (RDS) to the Employer Group Waiver Plan (EGWP) within the PRM Plan. Since OTP's PRM Plan previously provided a prescription drug component, OTP was eligible for the RDS, providing some relief to the costs within the post-retirement medical expense. More recently, the RDS benefit has been reducing, and moving to EGWP was found to be much more beneficial, especially in the short-term.

Q. HAS THE TRANSITION TO EGWP OCCURRED OVER TIME?

A. Yes. We started moving non-union retirees to EGWP in 2020. In 2021, we transitioned retirees who ended their careers under a collective bargaining agreement to EGWP. The adoption of the EGWP will permanently reduce PRM expenses, but the majority of the expenses were recognized during the first four years following the transition.

Q. HAS OTP TAKEN OTHER STEPS TO MANAGE THE COST OF THE PRM PLAN?

A. Yes. In 2023, OTP made the decision to move to a private exchange for Medicare-eligible retirees (post-65), with all Medicare supplemental medical and prescription benefits no longer being provided through our self-insured plan. All age-65 and older retirees will move to the Mercer Marketplace Exchange effective January 1, 2024. The move will provide more comprehensive coverage opportunities for retirees, while significantly reducing the PRM expenses, as discussed by Mr. Gerhardson and Ms. Petersen in their respective Direct Testimonies. These expense reductions are expected to continue long term.

Q. HAS OTP BEEN PRUDENT IN ESTABLISHING AND THEREAFTER CONTROLLING THE COSTS OF ITS DEFINED BENEFIT PENSION PLAN?

A. Yes. Defined benefit pension plans were very common when OTP established its defined benefit pension plans in 1975, and OTP's decision to establish such a plan was prudent and consistent with industry compensation and benefit practices. Since then, OTP has continued to be prudent in managing its pension plans and other retirement benefits, as I explained earlier. Most importantly, it has frozen participation in the Pension Plan.

Q. ARE OTP'S BENEFIT PLANS REASONABLE COMPARED TO THE MARKET?

A. Yes. In addition to the studies of cash compensation that I discussed earlier in my Direct Testimony, OTP also routinely participates in the Willis Towers Watson (WTW) Energy Services BenVal Study. A copy of the 2023 WTW Energy Services BenVal Study (2023 BenVal Study) is provided as Exhibit___(PEW-1), Schedule 5.

Q. PLEASE DESCRIBE THE 2023 BENVAL STUDY.

A. The 2023 BenVal Study focused on new hires and included 37 participating energy services companies. The companies were further defined by revenue size. The 2023 BenVal Study showed OTP's relative benefit program value compared to participating companies of similar revenue size was 10 out of 12. The BenVal Study shows OTP near the middle for current medical benefits provided, and toward the bottom when looking at OPEBs. Overall, the BenVal Study shows that OTP benefits are lower than most of the other participating utility companies.

Q. WHAT ARE THE IMPLICATIONS OF HAVING A BENEFIT PACKAGE WITH A LOWER BENEFIT VALUE?

A. Having a lower benefit value could inhibit OTP's ability to attract, retain and engage the talented workforce needed to deliver safe and reliable electric service to our customers. It is imperative that we continue to offer a compensation and benefit package that is competitive for our employees and a good value to our customers. We will continue to monitor our benefit package going forward to ensure it doesn't become a detriment.

VI. 2024 TEST YEAR EMPLOYEE COMPENSATION COSTS

Q. PLEASE IDENTIFY THE COSTS OF OTP'S COMPENSATION PLAN THAT ARE INCLUDED IN THE 2024 TEST YEAR.

A. The 2024 Test Year includes costs of the following components of the OTP compensation plan: (1) wages and salaries; (2) annual incentives; (3) employee health and dental benefit plans; and (4) retirement savings, pension and other postretirement employee benefits. Except for pension and PRM expenses, which are discussed by Mr. Gerhardson and Ms. Petersen, I discuss these expenses below.[2]

A. Wages and Salaries

Q. WHAT IS THE 2024 TEST YEAR WAGE AND SALARY EXPENSE?

A. The 2024 Test Year reflects $55 million (OTP Total) / $24 million (OTP ND EST) of base wage and salary expense.

Q. HOW WERE 2024 WAGE AND SALARY LEVELS DETERMINED?

A. The 2024 base wages and salaries are based on a four percent increase over the base wage and salary level for 2023 for both union and non-union employees. The wage and the salary components for 2024 also have been adjusted for the projected employee census. The four percent increase reflects what OTP believes is necessary to remain competitive in the labor market in which it competes. Accordingly, its main purpose is to maintain competitive compensation levels and address changes in the cost of living.

[2] Unless otherwise noted herein, all amounts shown in this section are total costs, including any capitalized costs.

Q. HOW DO THE NUMBER OF FTE EMPLOYEES IN 2023 COMPARE TO THE NUMBER IN 2024?

A. As of September 2023, OTP had approximately 798 FTE employees and our 2024 budget indicates an average of 800 FTE employees, an increase of 2. The primary reason for the increase is the number of open positions in 2023. In October of 2023, we had 18 open full-time positions, with some of those being offset by upcoming retirements.

Q. PLEASE FURTHER EXPLAIN THE 2024 WAGE INCREASE FOR NON-UNION EMPLOYEES OTHER THAN MANAGEMENT.

A. OTP budgeted for a four percent wage increase for non-union employees effective April 1. The four percent increase is cumulative and individual employee increases will vary depending on performance, market data, and where the employee's wage falls within the respective wage range.

Q. WHAT WAS THE SOURCE OF THE 2024 WAGE INCREASE FOR UNION EMPLOYEES?

A. OTP has two collective bargaining agreements (CBAs) representing approximately 375 union employees: (1) a CBA with four International Brotherhood of Electrical Workers (IBEW) Local Unions representing approximately 315 employees; and (2) a CBA with one IBEW Local Union representing approximately 60 Coyote Station employees. Both CBAs were renegotiated in 2023, resulting in the following wage increases:

Table 2

CBA Wage Increases – Coyote IBEW

Period	IBEW - Coyote
Sept 1, 2022 – Aug. 31, 2023	**[PROTECTED DATA BEGINS…**
Sept 1, 2023 – Aug 31, 2024	
Sept 1, 2024 – Aug 31, 2025	
Sept 1, 2025 – Aug 31, 2026	**… PROTECTED DATA ENDS]**

CBA Wage Increases – Other IBEW

Period	IBEW – Other
Nov 1, 2022 – Oct 31, 2023	**[PROTECTED DATA BEGINS…**
Aug 16, 2023 – Oct 31, 2024	
Nov. 1, 2024 – Oct. 31, 2025	
Nov. 1, 2025 – Oct. 31, 2026	**… PROTECTED DATA ENDS]**

Q. PLEASE FURTHER EXPLAIN THE 2024 WAGE INCREASE FOR MANAGEMENT AND EXECUTIVE EMPLOYEES.

A. The four percent non-union wage increases for management and executive employees is effective April 1. The four percent increase is cumulative and individual employee increases will vary depending on performance, market data, and where the employee's salary falls within the respective wage range.

B. Annual Incentives

Q. WHAT IS THE 2024 TEST YEAR ANNUAL INCENTIVE EXPENSE?

A. The 2024 Test Year reflects \$3.28 million (OTP Total) / \$1.43 million (OTP ND EST) of annual incentive expense. These amounts can be further broken down as follows:

Table 3
2024 Test Year Annual Incentive Program Expenses

Program	OTP Total	OTP ND EST
KPA Plan	**[PROTECTED DATA BEGINS…**	
People Leaders		
Coyote Retention Incentive Plan		
Management Plan		
OTP President		**… PROTECTED DATA ENDS]**

Q. DOES TABLE 3 REFLECT THE FULL COST OF OTP'S ANNUAL INCENTIVE PROGRAMS?

A. No. OTP has limited its request for Annual Incentive Plan cost recovery by excluding amounts that exceed 25 percent of an individual's base salary.[3]

Q. DID OTP APPLY THE SAME CAP TO THE 2024 TEST YEAR COSTS OF THE OTP PRESIDENT'S INCENTIVE PLAN?

A. Yes. The OTP president's target incentive is 60 percent of base pay, but OTP is also proposing to limit the level of incentive compensation recovered in rates to 25 percent of the OTP president's individual base salary.

Q. WHY IS IT APPROPRIATE TO INCLUDE THE COSTS OF THE OTP ANNUAL INCENTIVE PLAN IN THE 2024 TEST YEAR REVENUE REQUIREMENT?

A. The costs of the OTP Annual Incentive Plan should be included in the 2024 Test Year revenue requirement for several reasons. First, OTP's Annual Incentive Plan is an important part of OTP's total compensation plan; without it, OTP's total cash compensation would be significantly below market, making it harder for OTP to attract and retain essential employees. Second, as I have explained earlier in my Direct Testimony, the OTP Annual Incentive Plan includes an appropriate range and balance of factors that provide benefits to customers. Third, including annual incentive plans in total compensation packages is an established utility market

[3] There are 14 OTP management employees in the OTP Management Plan that have 2024 target maximum payout levels that exceed 25 percent of their base salaries. The amount in excess of 25 percent has been excluded from the 2024 Test Year revenue requirement.

practice. Fourth, OTP has applied appropriate controls to the costs to be recovered in the revenue requirement.

Q. HOW DO OTP'S CONTROLS SUPPORT RECOVERY OF THE PROPOSED INCENTIVE COSTS?

A. When the 25 percent cap is applied, OTP's annual cash compensation levels for executive compensation are even further below competitive market levels. The 2024 forecasted level for the Management Plan, adjusted to remove any amounts over a 25 percent cap on individual employee incentives, is appropriate for determining OTP's revenue requirement because it is consistent with historic payout levels.

Q. DID OTP INCLUDE ANY AMOUNTS FOR ACHIEVEMENT AWARDS IN THE 2024 TEST YEAR?

A. Yes, while there was a certain amount excluded from the 2018 Test Year revenue requirement established by settlement in OTP's last North Dakota rate case, OTP continues to believe these costs are necessary and appropriate. As noted above, while modest, Achievement Awards are used to recognize and reward employees that have performed exceptionally well on special projects or challenging work outside of normal assignments. These awards are not only part of a successful total employee compensation program, they are directly attributable to a particular project benefiting customers. OTP therefore included $225,000 (OTP Total)/ $97,000 (OTP ND EST) of Achievement Award expenses in the 2024 Test Year.

Q. DID OTP INCLUDE ANY AMOUNTS FOR LONG-TERM INCENTIVE IN THE 2024 TEST YEAR?

A. Yes. OTP included $2.8 million (OTP Total)/ $1.2 million (OTP ND EST) of long-term incentive expense in the 2024 Test Year. These expenses take the form of RSUs.

Q. HOW WERE RSU COSTS TREATED IN THE SETTLEMENT FOR THE LAST NORTH DAKOTA RATE CASE AND WHY IS IT REASONABLE TO INCLUDE RSU COSTS IN THE 2024 TEST YEAR?

A. While settlement in OTP's last North Dakota rate case excluded RSUs from the 2018 Test Year revenue requirement, OTP continues to believe that recovery of these costs strengthens OTP's workforce. As noted above, long-term incentives in the form of RSUs: (1) link the long-term success of OTP to qualifying employee compensation; (2) encourage the retention of management over the long-term; and (3) provide the opportunity to earn competitive total compensation.

Q. PLEASE EXPLAIN HOW RESTRICTED STOCK UNITS LINK LONG-TERM SUCCESS OF OTP TO EMPLOYEE COMPENSATION.

A. RSUs are a part of an overall compensation package for executives and key management employees. RSUs allow OTP to attract and retain key talent – with the skills and experience necessary to successfully operate the Company. RSUs also allow OTP to remain competitive within the market, in which historically, OTP executives have been below the market median.

Q. WHY DO RESTRICTED STOCK UNITS ENCOURAGE RETENTION?

A. OTP's RSU program has a vesting period of four years, with each award being subject to its own vesting period. Thus, individuals only earn their RSUs after a sustained period with the Company. Further, the RSUs reward performance by creating a longer-term perspective and aligning management interests with both customer and Company interests.

Q. WOULD OTP NEED TO UTILIZE OTHER FORMS OF COMPENSATION IF IT DID NOT HAVE AN RSU PROGRAM?

A. Yes. The RSU program (and long-term incentives generally) represents a part of the total compensation package for qualifying management personnel. As discussed above, OTP's executive personnel already receive below-average compensation, as compared to the market. It is not reasonable to assume that OTP could eliminate the RSU form compensation and see no effect in its ability to retain existing (or attract new or replacement) executive personnel. Thus, the alternative to use of RSUs is some other form of compensation, not a reduction of the total amount of compensation. Given the benefits of RSUs discussed above, these are reasonable parts of the 2024 Test Year cost of service.

C. Medical, Dental, 401(k) and Other Benefits Expenses

1. Active Medical and Dental

Q. WHAT IS THE 2024 TEST YEAR AMOUNT FOR OTP'S ACTIVE MEDICAL AND DENTAL COSTS?

A. The 2024 Test Year reflects $11.7 million (OTP Total) / $5.1 million (OTP ND EST) of active medical and dental costs.

Q. HOW DID OTP DETERMINE ITS ACTIVE MEDICAL AND DENTAL COSTS FOR THE 2024 TEST YEAR?

A. OTP has utilized third parties to determine active medical costs for many years and has determined it to be an effective method to project future active employee medical costs. The 2024 Renewal Results, prepared by Mercer, are provided as Exhibit___(PEW-1), Schedule 6. I note, however, that the 2024 Test Year reflects an earlier, and lower, Mercer estimate of 2024 expenses. Actual 2024 expense, as shown in the 2024 Renewal Results, are expected to exceed the amounts included in the Test Year.

2. 401(k)

Q. WHAT IS THE 2024 TEST YEAR AMOUNT FOR OTP'S 401(K) COSTS?

A. The 2024 Test Year reflects $3.7 million (OTP Total) / $1.63 million (OTP ND EST) of 401(k) costs.

Q. HOW DID OTP DETERMINE ITS 401(K) COSTS FOR THE 2024 TEST YEAR?

A. OTP utilizes current participation and contributions to project an estimate for the current year. Year-to-date forfeitures are then removed from the projected estimate. For 2023, anticipated employer match changes were calculated based on the projected estimates then added to the net employer match total. An escalator was then applied to the net employer match total to arrive at 2024 values.

3. Postemployment (LTD) Medical Benefit Plan Costs for ERPP and ESSRP

Q. WHAT IS THE 2024 TEST YEAR AMOUNT FOR OTP'S ERPP COSTS?

A. OTP has included $210,000 (OTP Total) / $92,000 (OTP ND EST) for ERPP in the 2024 Test Year.

Q. HOW DID OTP CALCULATE ERPP COSTS FOR THE 2024 TEST YEAR?

A. Eligible compensation is based on the annual salaries and target short-term incentive payout of participants in 2023 and was adjusted to account for anticipated annual wage increases for the test year. Any wages above the annual compensation dollar limit are adjusted back to the cap amount. Contribution percentages were verified in accordance with plan documents.

Q. WHY IS IT APPROPRIATE TO INCLUDE THE COST OF THE ERPP IN THE 2024 TEST YEAR?

A. The ERPP is a necessary component of OTP's overall compensation and benefits package for certain key executives and key management employees. Absent this component of compensation, it would be more difficult to provide a competitive compensation package for key executive and management employees, whose compensation levels already lag market medians.

Q. WHAT IS THE 2024 TEST YEAR AMOUNT FOR OTP'S ESSRP COSTS?

A. OTP has included $610,000 (OTP Total) / $267,000 (OTP ND EST) for the ESSRP in the 2024 Test Year.

Q. HOW DID OTP CALCULATE ESSRP COSTS FOR THE 2024 TEST YEAR?

A. The costs for the 2024 Test Year is calculated through a third-party actuary, Mercer, and provided in an ASC 715 report.

Q. WHY IS IT APPROPRIATE TO INCLUDE THE COST OF THE ESSRP IN THE 2024 TEST YEAR?

A. Like the ERPP, the ESSRP is component of a competitive overall compensation and benefits package for certain key executives and key management employees. While the settlement in the last North Dakota rate case excluded a portion of ESSRP costs from the revenue requirement, OTP continues to believe that recovery of these costs is a necessary component to its compensation package. Although this benefit has been reduced in recent years, and ultimately frozen for participants, and closed to new participants, it is part of our overall reasonable compensation and benefits package designed to retain quality leadership within OTP.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. OTP has structured a reasonable total cash compensation and benefits package that is needed to attract and thereafter retain and engage talented employees necessary to provide high quality electric service to our customers. This includes base salaries, active and post-retirement benefits, and incentive compensation. OTP's proposed compensation and benefit costs are fair and reasonable and should be included in rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

PETER E. WASBERG

EMPLOYMENT

2008 – PRESENT Otter Tail Power Company Fergus Falls, MN
Director, Human Resources & Safety

2004 – 2008 Otter Tail Power Company Fergus Falls, MN
Manager, Human Resources

2002 – 2004 Otter Tail Power Company Crookston, MN
Area Manager, Crookston & Bemidji

1997 – 2002 Otter Tail Power Company Hallock, MN
Division Manager, Hallock & Crookston Divisions Crookston, MN

1995 – 1997 Otter Tail Power Company Bemidji, MN
Office Manager, Bemidji Division

1991 – 1995 Otter Tail Power Company Milbank, SD
Division Accountant, Milbank Division

EDUCATION

- Bachelor of Arts — Concordia College, Moorhead
  - Business Administration
  - Psychology
- Management Institute — University of Wisconsin – Madison
  - Coaching & Counseling
  - Full-Range Leadership
- Executive and Organizational Development — The Levinson Institute

PROFESSIONAL AFFILIATIONS

- University of Minnesota, Crookston — All-College Advisory & Advancement Board
- Society of Human Resources Management (SHRM) — Member
- MN Energy Consortium — Advisory Group
- Fergus Falls Public Library — Director

Mercer

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Otter Tail Power Company

Compensation Competitiveness Study 2022

October 06, 2023

Damien McGuigan
Ashwini Kumar
Sophie Sawicki

A business of Marsh McLennan

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Schedule 2 – Mercer 2022 Compensation Competitiveness Study

to

Direct Testimony of Peter E. Wasberg

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility Service in North Dakota

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OTTER TAIL POWER COMPANY

Executive Benchmarking - 2022

Damien McGuigan
Ashwini Kumar
Sophie Sawicki

A business of Marsh McLennan

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Schedule 3 – Mercer 2022 Executive Benchmarking

to

Direct Testimony of Peter E. Wasberg

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility Service in North Dakota

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Summary Plan Description – Retirement Savings Plan

Retirement savings plan - Coyote Station union employees (hired on or after January 1, 2009)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	100%
Contribution amount	1% - 50% of pay
Matching company contribution	50% of the first 6% contributed by employee
Enhanced Employer Contribution	7% of annual salary
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Retirement savings plan - Coyote Station union employees (hired before January 1, 2009)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	100%
Contribution amount	1% - 50% of pay
Matching company contribution	50% of the first 6% contributed by employee
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Summary Plan Description – Retirement Savings Plan

Retirement savings plan - nonunion employees (hired before September 1, 2006)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	5 year vesting schedule (20% each year)
Contribution amount	1% - 50% of pay
Matching company contribution	50% of the first 6% contributed by employee
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Retirement savings plan - nonunion employees (hired on or after September 1, 2006)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	5 year vesting schedule (20% each year)
Contribution amount	1% - 50% of pay
Matching company contribution	50% of the first 8% contributed by employee
Enhanced Employer Contribution	5% of annual salary
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Summary Plan Description – Retirement Savings Plan

Retirement savings plan - union employees hired prior to 11/1/2013 (does not apply to Coyote union employees)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	100%
Contribution amount	1% - 50% of pay
Matching company contribution	50% of the first 6% contributed by employee
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Retirement savings plan - union employees (hired on or after November 1, 2013 - does not apply to Coyote union employees)	
Read the full retirement savings plan SPD.	
Type	Defined Contribution (401(k))
Eligibility	You must attain age 18.
Participation	First of the month following eligibility Automatic enrollment at a 3% deferral rate
Vesting	100%
Contribution amount	1% - 50% of pay
Enhanced Employer Contribution	5% of annual salary
Matching company contribution	50% of the first 8% contributed by employee
Investment options	25 fund options with Principal
Payment options	Lump sum distribution at termination, death, disability, or age 59½. Must be paid in full by age 73.
In-service withdrawals	Age 59 ½ withdrawals - Rollovers
Loans	Available (2)

Summary Description of Otter Tail Power Pension Plans

Pension plan –Coyote Station Union Employees (hired before January 1, 2009)	
Type	Defined Benefit
Eligibility	Age 18 and date of hire
Benefit Accrual Service	1,000 hours service in a year
Formula	(.38(Final Average earnings (36 months)) + .18(Final Average Earnings – Covered Compensation)) * (Years of service up to 30/30) + 1% for each year of service from 31 – 40 years
Final Average Earnings	Highest 3 year average of past 10 years
Covered Compensation	35 year average of SS taxable wage base ending in year prior to Normal Social Security Retirement Age
Vesting	Cliff: 100% after five years of Benefit Accrual Service
Normal retirement age	65
Early retirement age	Age 55 with at least 10 years of service
Early retirement reductions	Age 62 – 64: None Age 57 - 61: 5% per year prior to age 62 Age 55 - 56: 7% per year prior to age 57
Funding	Employer
Form of payment	50% J&S Annuity, 50%/75%/100% Survivor Annuity, 10-year Certain, Reversion Option
Pension Purchase Option	Roll-over portion of Retirement Savings Plan balance – buys additional annuity
Pre-retirement death benefits	Greater of Qualified Pre-retirement Death Benefit on date of death or 25% of pay

Summary Description of Otter Tail Power Pension Plans

Pension plan – Nonunion Employees (hired before September 1, 2006) & Union Employees (hired before 11/1/2013 – does not apply to Coyote Union Employees)	
Type	Defined Benefit
Eligibility	Age 18 and date of hire
Benefit Accrual Service	1,000 hours service in a year
Formula	(.38(Final Average earnings (30 months)) + .18(Final Average Earnings – Covered Compensation)) * (Years of service up to 30/30) + 1% for each year of service from 31 – 40 years
Final Average Earnings	Highest 2.5 year average of past 10 years
Covered Compensation	35 year average of SS taxable wage base ending in year prior to Normal Social Security Retirement Age
Vesting	Cliff: 100% after five years of Benefit Accrual Service
Normal retirement age	65
Early retirement age	Age 55 with at least 10 years of service
Early retirement reductions	Age 62 – 64: None Age 57 - 61: 5% per year prior to age 62 Age 55 - 56: 7% per year prior to age 57
Funding	Employer
Form of payment	50% J&S Annuity, 50%/75%/100% Survivor Annuity, 10-year Certain, Reversion Option
Pension Purchase Option	Roll-over portion of Retirement Savings Plan balance – buys additional annuity
Pre-retirement death benefits	Greater of Qualified Pre-retirement Death Benefit on date of death or 25% of pay

Otter Tail Power Company – Retirement Benefits Eligibility

Employee Group	Eligible for Pension	Eligible for 401(k) Enhanced Contribution – 5%	Eligible for 401(k) Enhanced Contribution – 7%	Eligible for 401(k) Match; 50% of the First 6% (max – 3.0%)	Eligible for 401(k) Match; 50% of the First 8% (max – 4.0%)	Eligible for Retiree Medical
Non-union hired prior to 9/1/2006	X			X *Effective 1/1/2024*		X
Non-union hired 9/1/2006 or after		X *Effective 1/1/2024*			X *Effective 1/1/2024*	
Coyote Union hired prior to 1/1/2009	X			X		X
Coyote Union hired 1/1/2009 or after			X	X		
Other Union hired prior to 11/1/2013*	X			X *Effective 11/1/2023*		X
Other Union hired 11/1/2013 or after		X			X *Effective 11/1/2023*	

*Employees in this group, hired after 10/31/2010, are not eligible for Retiree Medical

Other Notes

Prior to 1/1/2024:

- Non-union, pension employees 401(k) match was 50% of the first 5% (max – 2.5%)
- Non-union, non-pension employees enhanced was 4% and 401(k) match was 50% of the first 5% (max – 2.5%)

Prior to 11/1/23:

- Other union, pension employees 401(k) match was 50% of the first 5% (max – 2.5%)
- Other union, non-pension employees 401(k) match was 50% of the first 6% (max – 3%)

2023 Energy Services Benefits Study

BenVal for Otter Tail Corporation

October 2023

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Schedule 5 – Report of the 2023 Willis Towers Watson Energy Services BenVal Study
to
Direct Testimony of Peter E. Wasberg

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility Service in North Dakota

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Mercer

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2024 Benefits Overview and Considerations

Otter Tail Power

October 16, 2023

A business of Marsh McLennan

[PROTECTED DATA BEGINS…

Schedule 6 – Mercer 2024 Renewal

to

Direct Testimony of Peter E. Wasberg

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility Service in North Dakota

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Volume 2B

Direct Testimony and Supporting Schedules:

Tammy K. Mortenson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit_

SALES FORECAST

Direct Testimony and Schedules of

TAMMY K. MORTENSON

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

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ATTACHED SCHEDULES

Schedule 1 – Mortensen Statement of Qualifications

Schedule 2 – OTP Sales and Revenue Forecast Methodology – NOT PUBLIC

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Tammy K. Mortenson. I am employed by Otter Tail Power Company (OTP).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Senior Data Analyst in the Business Planning Department. I am responsible for creating the Sales and Demand forecasts for OTP.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(TKM-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to discuss OTP's energy forecasting process and present the results of OTP's sales forecast, which forms the basis of the 2024 Test Year sales and revenues in this proceeding.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. OTP forecasts approximately 2,560 gigawatt hours (GWh) of North Dakota retail sales in the 2024 Test Year. OTP's sales forecast includes refinements on the process used in OTP's last North Dakota rate case (Case No. PU-17-398). OTP's 2024 Test Year sales are reasonable and form an appropriate basis for establishing rates in this case.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss the sales forecast methodology. In Section IV, I discuss the test year sales forecast class-by-class.

III. SALES FORECAST METHODOLOGY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I will discuss the methods OTP uses to forecast sales. Additional details regarding our sales forecast methodology, including procedures used to develop the sales forecasts, are provided in Exhibit___(TKM-1), Schedule 2.

Q. WHAT METHODS DOES OTP USE TO FORECAST SALES?

A. OTP prepares sales forecasts for eight separate customer groupings, or sales forecast classes, though only seven are part of the calculation of retail rates.[1] As shown in the table below, OTP uses a mixture of statistical models and manual forecasts to develop its sales forecast.

Table 1
OTP Sales Forecast Classes

Sales Forecast Class	Forecast Methodology
Residential	Statistical – UPM and Meters
Farm	Statistical – UPM and Meters
Small Commercial	Statistical – UPM and Meters
Large Commercial	Statistical – Total Sales / Manual
Pipeline / Industrial	Manual
Other Public Authority	Statistical – UPM and Meters
Area / Street Lighting	Manual

Q. HAS OTP REFINED ITS STATISTICAL-BASED FORECAST METHODOLOGIES SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. In 2020, OTP worked with Dr. Daniel G. Hansen of Christensen Associates Energy Consulting, LLC to refine the statistical models used in its sales forecast process. Since that time, the refined sales statistical models have supported all of OTP's regulatory and financial filings.

Q. WHAT IS THE PRIMARY REFINEMENT TO THE STATISTICAL FORECAST MODELS?

A. OTP replaced customer-level forecasting with meter-level forecasting, transitioning to a use-per-meter (UPM) model for most statistically forecasted classes. Large Commercial sales are developed using a total sales model (rather than separate UPM and number of meters models) because of the effects of a

[1] Unclassified sales, which pertain to OTP's own use of electricity, are not part of the calculation of retail rates.

reclassification of some higher-use Small Commercial customers into the Large Commercial class that occurred during the analysis period.

Q. WHY DOES THE LARGE COMMERCIAL CLASS FORECAST USE A TOTAL SALES MODEL?

A. There are two reasons. First, there are four Large Commercial customers that are manually forecasted outside of the statistical model. Using a total sales approach makes it easier to incorporate the sales of these manually forecasted customers. Second, some higher-use Small Commercial customers moved into the Large Commercial class during the historical period, which distorted the resulting UPM. Because of the resulting change in the average meter usage during the analysis period, a more straightforward approach was to model total usage.

Q. HOW WERE THE SALES FORECASTS CREATED FOR THE UPM-BASED CUSTOMER CLASSES?

A. The kilowatt hour (kWh) sales forecast is created from separate forecasts of UPM and the number of meters served per customer class. Specifically, for each forecast month, the sales forecast equals the product of the UPM forecast and the meter forecast.

Q. WHY SEPARATE THE SALES FORECAST INTO THE UPM AND METER COMPONENTS?

A. Dividing the sales forecast into the UPM and meter components improves OTP's ability to distinguish between the effect of drivers on meter-level usage versus the number of meters served. For example, one would expect variations in weather conditions to explain some of the variation in average per-meter usage levels (e.g., the average customer uses more when summer weather is hotter, all else equal), but weather variations should not be a significant driver of the number of meters served. By separating the sales forecast into UPM and meter models, OTP is better able to isolate the effect of weather on UPM. A similar effect and rationale for dividing the sales forecast into the UPM and meter components applies to other explanatory variables. A customer-meter may use more electricity as economic conditions improve and/or more customers (and hence meters) may be attracted to the service territory by improved economic conditions. These potential effects can be separately estimated using these methods.

Q. WHAT TIME PERIOD IS INCLUDED IN THE STATISTICAL MODELS?

A. Each model is estimated using 20 years of monthly historical data beginning January 2003 and ending December 2022. The forecast is developed using 20-year normal weather conditions and forecast economic and demographic conditions for 2024 provided by Woods & Poole Economics, Inc. (W&P).

A. Residential

Q. PLEASE DESCRIBE THE STATISTICAL MODELS USED IN OTP'S RESIDENTIAL SALES FORECAST.

A. The Residential sales forecast is the product of two models: a UPM model and a meter model.

1. Residential UPM Model

Q. PLEASE DESCRIBE THE RESIDENTIAL UPM MODEL.

A. The Residential UPM model includes the following variables:

1. The number of cooling degree days based on a 65-degree threshold (CDD65);
2. The number of heating degree days, based on a 55-degree threshold (HDD55);
3. The number of days in the billing month;
4. A linear time trend;
5. An indicator variable for January 2011 and beyond and an interaction of this variable with the linear time trend; and
6. Monthly indicator variables.

The dependent variable is UPM which is calculated by dividing Residential sales by the number of Residential meters. The model includes a correction for first-order serial correlation, which corrects for autocorrelation of a predicted value in the current period being a function of the immediate prior period error if it exists, which may occur in time series data. The UPM model leads to estimates of coefficients related to the variables.

Q. HOW IS CDD65 CALCULATED?

A. Cooling degree days (CDD65) are calculated by taking the average temperature for a particular weather station on a particular date and subtracting 65 degrees. If the difference is negative, the value is set to zero. This calculation is expressed in the following formula in which "s" stands for a given weather station and "t" represents the date:

$$CDD65_{s,t} = MAX\{(MaxTemp_{s,t} + MinTemp_{s,t}) / 2 - 65, 0\}$$

Once CDD65 is calculated, the values for the weather stations are combined using weights to reflect the Company's service territory.

Q. HOW IS CDD65 INTERPRETED?

A. CDD65 is intended to reflect the demand for cooling (i.e., air conditioner use). The model assumes that there is no cooling load below the daily average temperature of 65°F and that cooling load increases as temperatures increase above 65°F.

Q. HOW IS HDD55 CALCULATED?

A. Heating degree dates (HDD55) are calculated by subtracting the average temperature from 55 degrees. If the difference is negative, then HDD55 is set to zero. This calculation is expressed in the following formula:

$$HDD55_{s,t} = MAX\{55 - (MaxTemp_{s,t} + MinTemp_{s,t}) / 2, 0\}$$

The HDD55 values for the weather stations are then combined using weights to reflect the Company's service territory.

Q. HOW IS HDD55 INTERPRETED?

A. HDD55 reflects the demand for heating. The model assumes that there is no heating load when the daily average temperature is above 55°F and that heating load increases as temperatures fall below 55°F.

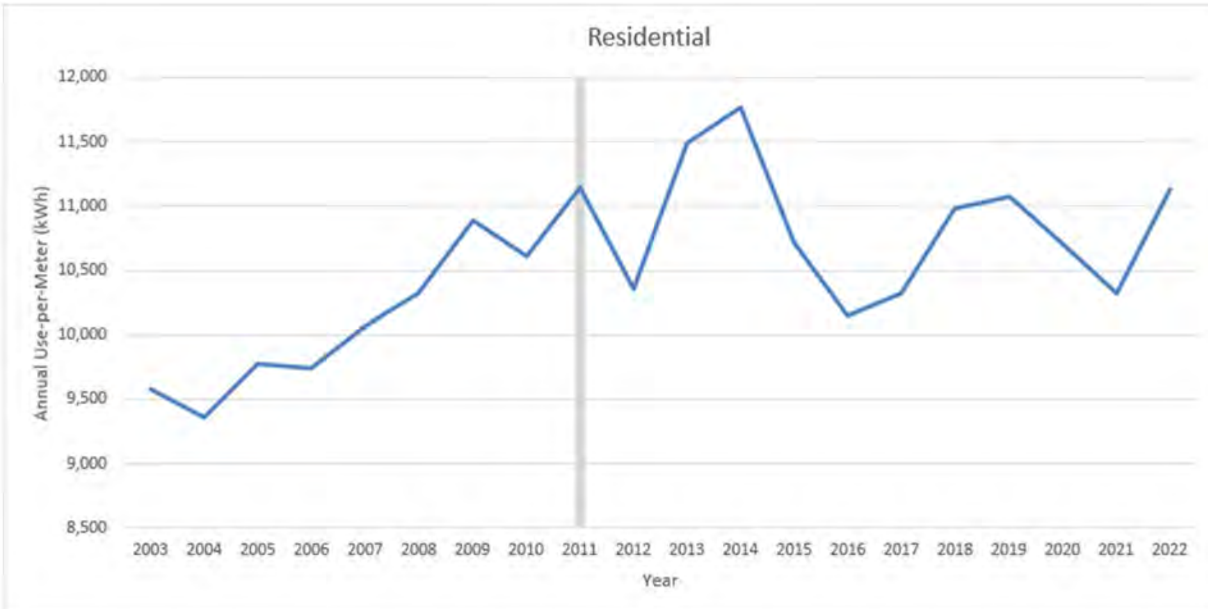
Q. WHAT IS THE PURPOSE OF THE LINEAR TIME TREND VARIABLE?

A. The linear time trend variable is intended to identify and account for any trend in Residential UPM, controlling for the other included variables (e.g., CDD and HDD). A time trend is appropriate when UPM is trending over time, but other available variables do not do a good job of explaining the trend.

Q. WHY DID OTP INCLUDE AN INDICATOR VARIABLE FOR JANUARY 2011 ONWARD?

A. Historical data shows that UPM was trending at a different rate prior to, as compared to after, 2011. As shown in the figure below, UPM generally increased prior to 2011 at an average annual rate of 2 percent. After 2011, UPM became more variable, so by including this variable and the associated trend we were able to more appropriately forecast future per-meter usage using a more current trend. This change in per-meter usage is likely related to energy efficiency seen in household appliances, electronics and lighting. The 2024 Test Year Residential UPM is 1.7 percent less than the actual 2022 weather normalized UPM.

Figure 1: Annual Residential Use-per-Meter, 2003 through 2022



Q. WHAT IS THE PURPOSE OF THE MONTHLY INDICATOR?

A. The monthly indicator variables reflect seasonal patterns in electricity usage that are not captured by the other variables. For example, lighting demand may vary seasonally due to changes in the number of daylight hours, which would not be well reflected by other included variables, such as CDDs and HDDs.

Q. ARE THE MONTHLY INDICATOR VARIABLES RELEVANT EXPLANATORY FACTORS?

A. Yes. The coefficients on the monthly indicator variables are jointly statistically significant, meaning they are relevant explanatory factors for this class. Together they provide for a similar annual coefficient but provide seasonal insight.

2. Residential Meter Model

Q. PLEASE DESCRIBE THE RESIDENTIAL METER MODEL.

A. The residential meter model is used to determine the number of Residential meters served during the billing month. The model uses the following variables:

1. A linear time trend; and
2. Monthly indicator variables.

Q. WHAT IS THE PURPOSE OF THE LINEAR TIME TREND VARIABLE?

A. The linear time trend variable is intended to identify and account for any trend in the number of Residential meters the Company is expected to serve. The model includes a correction for first-order serial correlation.

Q. DOES THE MODEL PRODUCE REASONABLE ESTIMATES?

A. Yes, the coefficient on the linear time trend variable is positive and statistically significant, indicating a pattern of growth of the number of Residential meters. The monthly indicator variables help account for the slight increase we see during warmer months where seasonal homes are reconnected for a period of time.

B. Farm

Q. PLEASE DESCRIBE OTP'S FARM FORECAST.

A. Two statistical models are estimated for OTP's Farm customers: a UPM model and a meter model.

1. Farm UPM Model

Q. PLEASE DESCRIBE THE FARM UPM MODEL.

A. The Farm UPM model includes the following variables:

1. HDD55;
2. The number of days in the billing month;
3. A linear time trend;
4. An indicator variable for May 2020; and
5. Monthly indicator variables.

The dependent variable in the UPM model is use-per-meter (sales divided by the number of meters) in each billing month. Note that we did not find a statistically significant relationship between UPM and cooling degree days for this class. The UPM model includes a correction for first-order serial correlation. The UPM model leads to estimates of coefficients related to the variables.

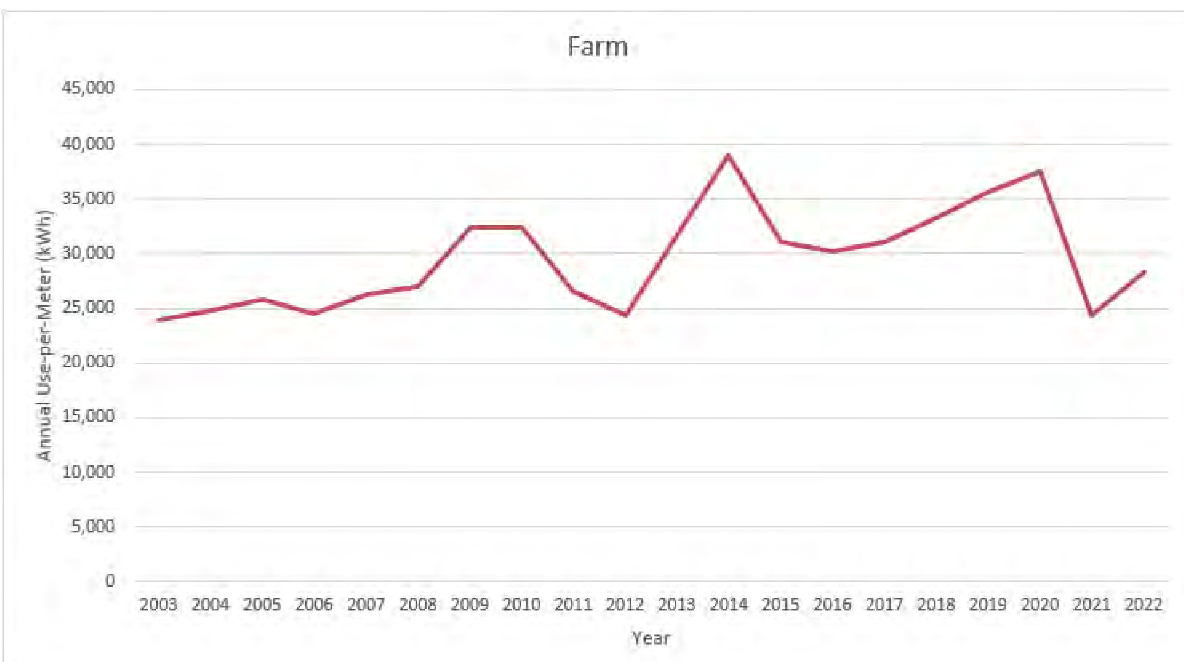
Q. ARE THE ESTIMATED COEFFICIENTS FROM THE FARM UPM MODEL REASONABLE?

A. Yes. The estimates can be summarized as follows:

- Farm UPM is positively related to HDDs (i.e., UPM increases when winter weather is colder);
- UPM increases with the number of billing days;

- Figure 2, below, shows the variability in the Farm class load, which consists primarily of grain drying. With 2013 being a well above average wet year, it created a significant amount of grain drying during the fall and winter months, causing a high UPM during 2013-2014. OTP also saw an average increase of 3 percent in meters annually between 2011-2014, which was likely another contributing factor to the increased UPM during that timeframe. Over the 20-year historical period, the Farm UPM had a 2 percent annual average growing trend prior to 2020, then the pandemic likely impacted sales in 2020. Beginning in 2021, Farm UPM is showing recovery, which is forecast to continue at a rate of approximately 1 percent annually, all else equal;
- Historical data by month shows that UPM in May 2020 was uncharacteristically high. By including an indicator variable for May 2020, the model will prevent that outlier from biasing the estimates of the other variables; and
- Seasonal patterns are relevant explanatory factors (i.e., the coefficients on the monthly indicator variables are jointly statistically significant).

Figure 2: Annual Farm Use-per-Meter, 2003 through 2022



2. Farm Meter Model

Q. PLEASE DESCRIBE THE FARM METER MODEL.

A. The dependent variable in the Farm meter model is the number of Farm meters served during the billing month. The model includes the following explanatory variables:

1. Farm Employment;[2] and
2. Monthly indicator variables.

Farm Employment is intended to reflect the economic and demographic factors that affect the number of farm meters the Company is expected to serve. The model includes a correction for first-order serial correlation.

Q. DOES THE METER MODEL PRODUCE REASONABLE ESTIMATES?

A. Yes, the interaction between farm employment and historical data reflects a positive relationship between economic conditions and meters served for the analysis period and extending into the forecast period. Although OTP historically saw growth in the farming class, economic predictors indicate there likely will be a decline in this sector, and our forecast reflects this. In addition, the monthly indicator variables are jointly statistically significant, reflecting a seasonal pattern in meters served.

C. Small Commercial

Q. PLEASE DESCRIBE OTP'S SMALL COMMERCIAL FORECAST.

A. The Small Commercial sales forecast is the product of two models: a UPM model and a meter model.

1. Small Commercial UPM Model

Q. PLEASE DESCRIBE THE SMALL COMMERCIAL UPM MODEL.

A. The Small Commercial UPM model includes the following variables:

1. CDD65;
2. HDD55;
3. The number of days in the billing month;
4. A linear time trend; and
5. Monthly indicator variables.

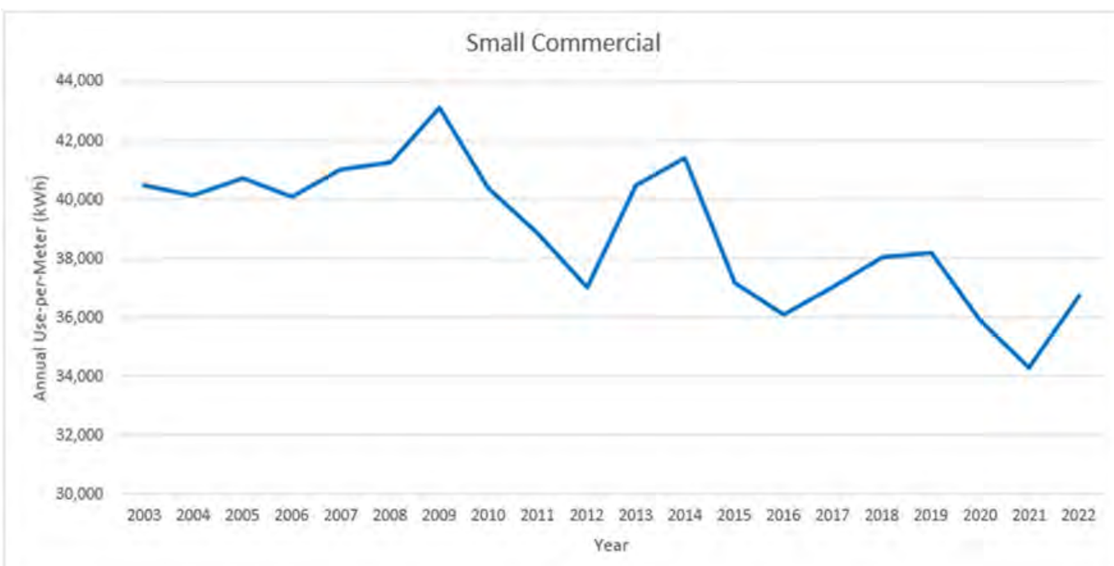
[2] Included as 12-month moving averages using the six prior months, the current month, and five following months.

The dependent variable is use-per-meter, which is sales divided by the number of meters, in each billing month. The model includes a correction for first-order serial correlation. The UPM model leads to estimates of coefficients related to the variables.

Q. WHAT IS THE PURPOSE OF THE LINEAR TIME TREND VARIABLE IN THE SMALL COMMERCIAL UPM MODEL?

A. A time trend is appropriate when UPM is trending over time, and other available variables do not do a good job of explaining the trend, which was accurate for the Small Commercial UPM. There has been some variability over the 20-year history, but Small Commercial UPM has had an overall decline of 9 percent from 2003 to 2022. During 2009 to 2012, there was a reclassification of meters from this class to the Large Commercial class resulting in a 5.0 percent average annual reduction of sales, while still seeing an average growth of 0.5 percent annually during this same time. The impact of the reclassification of meters was minimal to this class due to there being far more meters in this class. The addition of customers with higher sales accounted for the increase in UPM in 2013-2014 as seen in Figure 3. The scale has been condensed (i.e., starting at 30,000 kWh rather than zero) to make it easier to view trends in UPM.

Figure 3: Annual Small Commercial Use-per-Meter, 2003 through 2022



Q. ARE THE ESTIMATED COEFFICIENTS FROM THE SMALL COMMERCIAL UPM MODEL REASONABLE?

A. Yes. The estimates can be summarized as follows:

- Small Commercial UPM is positively related to both CDDs and HDDs (i.e., UPM increases when summer weather is hotter and winter weather is colder);
- UPM is more sensitive to CDDs than HDDs, which reflects a larger effect of temperatures on cooling-related load than heating-related load;
- UPM increases with the number of billing days;
- UPM has a declining trend of 27 kWh per meter per year, all else equal; and
- Seasonal patterns are relevant explanatory factors (i.e., the coefficients on the monthly indicator variables are jointly statistically significant).

2. Small Commercial Meter Model

Q. PLEASE DESCRIBE THE SMALL COMMERCIAL METER MODEL.

A. The dependent variable in the Small Commercial meter model is the number of Small Commercial meters served during the billing month. The model includes the following explanatory variables:

1. A linear time trend;
2. An indicator variable for 2007 and beyond; and
3. Monthly indicator variables.

The linear time trend reflects the increasing trend in meters served over time. Starting January 2007, the average growth in Small Commercial meters was less than in the prior years. The indicator variable for 2007 and beyond was found statistically significant in accurately predicting growth beginning in 2007. The model includes a correction for first-order serial correlation.

Q. DOES THE METER MODEL PRODUCE REASONABLE ESTIMATES?

A. Yes. The years prior to 2007 had an average annual growth rate of 0.9 percent, whereas the average growth rate for 2007 and beyond was 0.6 percent. Using the time trend variable and the 2007 and beyond variable together, the model predicts a reasonable increase of 878 meters served per year versus 937 meters without the time trend variable. When multiplying the growing meter counts with the declining use-per-meter, the forecasted energy sales were reasonable. The 2024 Test Year sales for this class are 0.2 percent lower than actual 2022 weather normalized sales.

D. Large Commercial and Pipeline

Q. PLEASE DESCRIBE OTP'S LARGE COMMERCIAL FORECAST.

A. As described earlier, a single statistical model is developed for OTP's Large Commercial customers representing total monthly sales. In addition to the model, OTP has several customers, including pipeline customers, that currently will not "fit" into the modeling process and are manually forecast.

1. Statistical Forecast

Q. PLEASE DESCRIBE THE LARGE COMMERCIAL SALES MODEL.

A. The Large Commercial sales model uses the following variables to determine total class sales in each billing month:

1. HDD55;
2. The number of days in the billing month;
3. Gross Regional Product (GRP) in conjunction with the years 2009 through 2010;
4. An indicator variable for January 2009 through December 2010;
5. An indicator variable for January 2011 and beyond;
6. Indicator variables for February 2019 and May 2019; and
7. Monthly indicator variables.

The model leads to estimates of coefficients related to the variables. The model includes a correction for first-order serial correlation.

Q. WHAT IS THE PURPOSE OF THE GRP VARIABLE?

A. GRP is a measure of the value of goods and services produced in a region. It is similar to gross domestic product (GDP), but whereas GDP measures economic activity at a national level, GRP measures it at a local level. It is intended to reflect the effect of economic conditions on class usage.

Q. WHAT IS THE PURPOSE OF INCLUDING THE GRP INDICATOR VARIABLE FOR THE YEARS 2009 THROUGH 2010?

A. There were two events that contributed to a change in Large Commercial sales from 2009 to 2011: (1) reclassification of some Small Commercial customers into the Large Commercial class; and (2) one very large customer coming online in

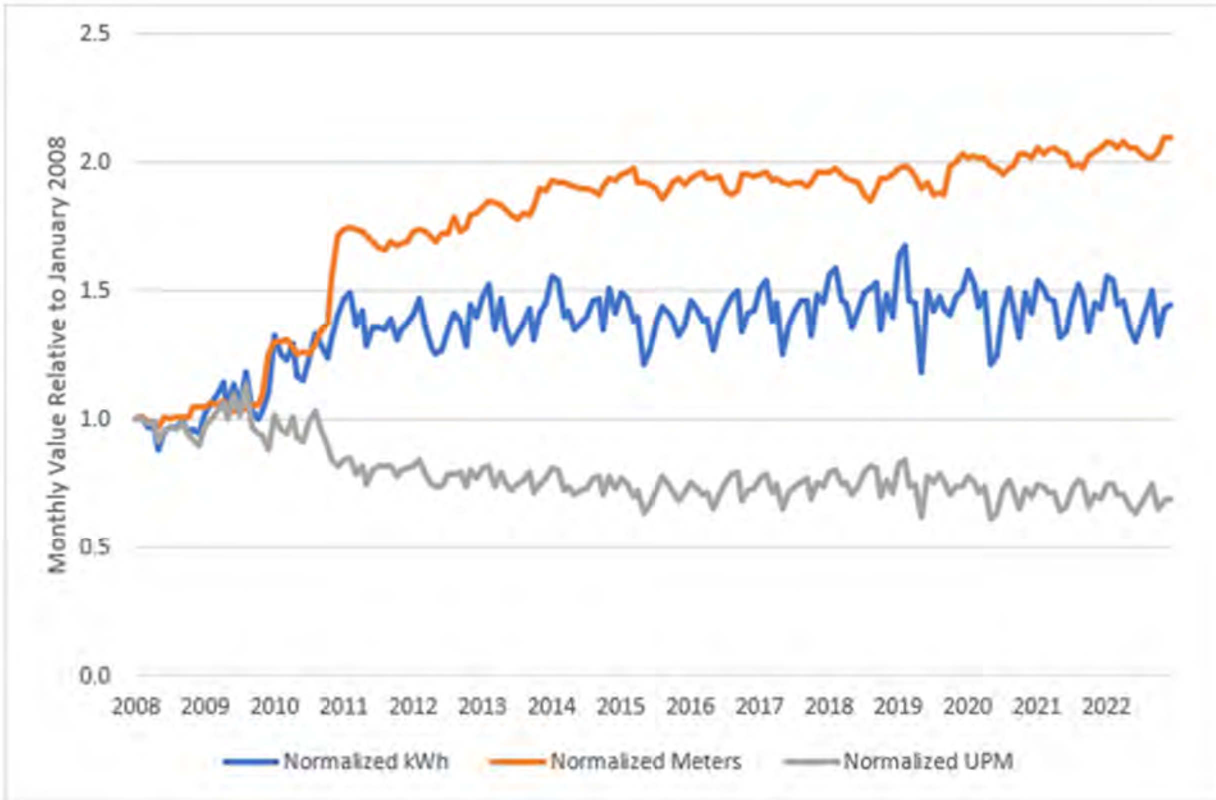
2009. The GRP indicator variable is used in the model to adjust for the changes in general economic conditions occurring at this same time.

Q. PLEASE DISCUSS THE RECLASSIFICATION OF SMALL COMMERCIAL CUSTOMERS INTO THE LARGE COMMERCIAL CLASS.

A. As mentioned earlier, from 2009 to 2011, there was a reclassification of some higher-use Small Commercial customers into the Large Commercial class. This reclassification contributed to the 7 percent increase in meters for 2009 (over 2008 levels), with an associated 4 percent growth in sales. 2010 saw a 26 percent increase in meters over the prior year, with an annual sales growth of 10 percent from the reclassification. Figure 4, below, shows the monthly total sales, number of meters, and UPM for the Large Commercial class normalized to their January 2008 value.[3] By normalizing to January 2008, we can more easily see how each series evolves over the analysis period on a single graph. There is an increase in the number of meters and a corresponding decrease in UPM from 2009 to 2011 due to the smaller commercial customers entering this class. At the same time, sales had a modest growth.

[3] Specifically, each graphed data point is equal to that month's value divided by the value in January 2008.

Figure 4: Large Commercial Sales, Number of Meters and Use Per Meter, Normalized to the January 2008 Level



Q. WHAT IS THE PURPOSE OF THE INDICATOR VARIABLE FOR JANUARY 2011 AND BEYOND?

A. With the significant change in sales, the January 2011 and beyond indicator variable allowed the model to more accurately forecast future sales based on the higher mean established after 2010.

Q. WHAT IS THE PURPOSE OF THE FEBRUARY 2019 AND MAY 2019 INDICATOR VARIABLES?

A. These variables control for anomalies in the historical billing information.

Q. ARE THE ESTIMATED COEFFICIENTS FROM THE LARGE COMMERCIAL SALES MODEL REASONABLE?

A. Yes. The estimates can be summarized as follows:

- Large Commercial usage is positively related to HDDs (i.e., usage increases when winter weather is colder);

- Usage increases with the number of billing days;
- The combined coefficients during January 2009 to December 2010, including the influence of GRP, produces the resulting sales during that timeframe;
- Large Commercial usage is higher following January 2011, all else equal;
- Indicator variables for February 2019 and May 2019 negate these outliers from affecting the overall coefficients of the other included variables; and
- Seasonal patterns are relevant explanatory factors (i.e., the coefficients on the indicator variables are jointly statistically significant).

2. Manual Forecasts

Q. WHAT CUSTOMERS ARE MANUALLY FORECASTED?

A. OTP has four Large Commercial class customers in North Dakota that are currently forecast manually, for various reasons, and added to the Large Commercial class model total. **[PROTECTED DATA BEGINS…**

….

PROTECTED DATA ENDS]

Q. CAN THESE CUSTOMERS' SALES BE ACCURATELY FORECAST WITH A STATISTICAL MODEL?

A. No. While we prefer to use statistical models to forecast sales for all customers, there are situations where models are not able to accurately capture the nuances of particular situations. This is particularly true for very large customers, as situations affecting their usage do not apply to the broader customer population.

Q. WHY ARE LARGE COMMERCIAL SALES DIFFICULT TO FORECAST USING ONLY STATISTICAL MODELS?

A. Due to the nature of their business, the energy needs of customers in this class can vary greatly, so when a new customer is introduced or an existing customer leaves, it has the potential to significantly impact the entire class. The large changes in load can be very difficult for a statistical model to predict. This class also has fewer meters providing input, so regular, predictable patterns may not emerge.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE EXTREME VARIABILITY OF LARGE COMMERCIAL SALES?

A. Yes. OTP had a single customer that represented nearly 10 percent or more of the total Large Commercial sales up until 2016 and by 2019 only represented 0.2 percent of the total sales. A load drop of this magnitude in this class would negatively influence the accuracy of a statistical model.

Q. ARE THERE OTHER UNIQUE CHARACTERISTICS THAT COMPLICATE FORECASTING LARGE COMMERCIAL SALES?

A. Yes. The entry of a large load in 2022 has had a significant impact on sales in this class. Also, behind-the-meter generation is emerging and may result in reduced sales in the future.

Q. WHY ARE PIPELINE SALES MANUALLY FORECAST RATHER THAN STATISTICALLY MODELED?

A. Pipeline sales are significantly impacted by world and national economic trends and federal and state energy and environmental policy. Further, the petroleum industry is in a state of constant flux. As shown in Figure 11, below, Pipeline sales can be quite variable **[PROTECTED DATA BEGINS ...**

... PROTECTED DATA ENDS]. This load is not a good candidate for a statistical model.

Q. HOW ARE THE MANUAL FORECASTS DEVELOPED?

A. Manual forecasts are developed by OTP employees that work directly with the manually forecast Large Commercial and Pipeline customers. These forecasts incorporate information provided by the customers, historic information (as applicable), comparisons of how the customers' projections have compared to actual results, and sales trends.

E. Other Public Authority

Q. PLEASE DESCRIBE OTP'S OTHER PUBLIC AUTHORITY FORECAST.

A. Two statistical models are estimated for OTP's Other Public Authority (OPA) customers: a UPM model and a meter model. OPA loads include municipal pumping and fire sirens.

1. OPA UPM Model

Q. PLEASE DESCRIBE THE OPA UPM MODEL.

A. The OPA UPM model includes the following variables:

1. HDD55;
2. The number of billing days; and
3. Monthly indicator variables.

The dependent variable in the UPM model is use-per-meter (sales divided by the number of meters) in each billing month. Note that we did not find a statistically significant relationship between UPM and cooling degree days for this class. The UPM model includes a correction for first-order serial correlation. The UPM model leads to estimates of coefficients related to the variables.

Q. ARE THE ESTIMATED COEFFICIENTS FROM THE OPA UPM MODEL REASONABLE?

A. Yes. The estimates can be summarized as follows:

- OPA UPM is positively related to HDDs (i.e., UPM increases when winter weather is colder);
- UPM increases with the number of billing days;
- UPM has remained mostly steady from 2003 to 2022, with only a 2.5 percent decrease (880 kWh) between the beginning and end of the 20-year period; and
- Seasonal patterns are relevant explanatory factors (i.e., the coefficients on the indicator variables are jointly statistically significant).

2. OPA Meter Model

Q. PLEASE DESCRIBE THE OPA METER MODEL.

A. The dependent variable in the OPA meter model is the number of OPA meters served during the billing month. The model includes the following explanatory variables:

1. A linear time trend;
2. Indicator variables for April 2019 and May 2021; and
3. Monthly indicator variables.

The model includes a correction for first-order serial correlation.

Q. DOES THE MODEL PRODUCE REASONABLE ESTIMATES?

A. Yes. The estimates can be summarized as follows:

- The model trend reflects modest growth in meters (approximately 1 per year);
- When viewing historical data by month, both April 2019 and May 2021 show a large increase in meter counts over their previous month followed by a similar average to all other months. This may occur if a certain set of customers are billed both at the beginning of a month and again at the end, so they receive two bills in one month. By including specific indicator variables for those months, the model will evaluate each time uniquely and estimate an appropriate coefficient to be used in the forecast of meters; and
- The monthly indicator variables are jointly statistically significant, reflecting a seasonal pattern in meters served.

F. Street Lighting and Area Lighting

Q. HOW WERE STREET AND AREA LIGHTING SALES FORECAST?

A. We developed an Excel-based template that forecasts Street Lighting and Area Lighting using two fundamental elements: sales during a recent 12-month period, and assumptions about the light-emitting diode (LED) fixture installation rate and the kWh savings realized when LED fixtures replace existing fixtures.

Q. WHY DID YOU USE THIS APPROACH RATHER THAN A STATISTICAL MODELING METHOD?

A. The largest expected change to Street Lighting and Area Lighting sales in coming years is expected to be due to replacing existing fixtures with LED fixtures. OTP believes LEDs reduce a fixture's electricity usage by 75 percent. Rather than attempt to estimate the change in sales from increased LED installations, which is currently in process, we use a simulation approach that adjusts historical lighting sales for the expected change in LED installations in each month.

Q. WHAT ASSUMPTIONS DOES YOUR STREET LIGHTING FORECAST USE?

A. We assume that LED installations occur from May through September of each year until LEDs comprise 69 percent of installations. In each month installations occur, the LED share increases by 3.3 percent. Finally, as described earlier, a fixture's usage is assumed to decline by 75 percent after LEDs are installed.

Q. DID YOU USE THE SAME GENERAL APPROACH TO FORECAST AREA LIGHTING SALES?

A. Yes. We forecast Area Lighting sales accounting for a LED installation schedule similar to the Street Lighting forecast, with a slightly slower installation rate and lower saturation level. The process for allocating Area Lighting sales to the relevant customer classes is described in Exhibit___(TKM-1), Schedule 2 under Class Forecasts of kWh.

IV. TEST YEAR SALES FORECAST

A. Overview

Q. WHAT IS OTP'S OVERALL FORECASTED 2024 TEST YEAR SALES?

A. OTP forecasts approximately 2,560 GWh of North Dakota retail sales in the 2024 Test Year. Table 2, below, identifies the 2024 Test Year sales by sales forecast class.

Table 2
Summary of 2024 Test Year Sales Forecast

Customer Class	kWh Sales
Residential	591,642,942
Farm	41,513,920
Small Commercial	467,433,150
Large Commercial and Pipeline[4]	1,433,405,558
Street Lighting	7,202,486
OPA	18,713,442
Total Sales	**2,559,911,498**

[4] Large Commercial and Pipeline sales are aggregated in order to protect the sales figures for the Pipeline class, which includes only one customer.

Q. WHAT ARE THE PRIMARY FACTORS CONTRIBUTING TO THE 2024 TEST YEAR SALES FIGURES?

A. OTP's service area in Minnesota, North Dakota, and South Dakota is made up of rural areas and small towns. For example, only three towns we serve have populations of more than 10,000, with only one being located in North Dakota (Jamestown). We do not anticipate significant economic or demographic growth for 2024, which is confirmed by the W&P data that informs our sales forecasts. The moderate growth in the W&P data translates to very moderate growth in sales.

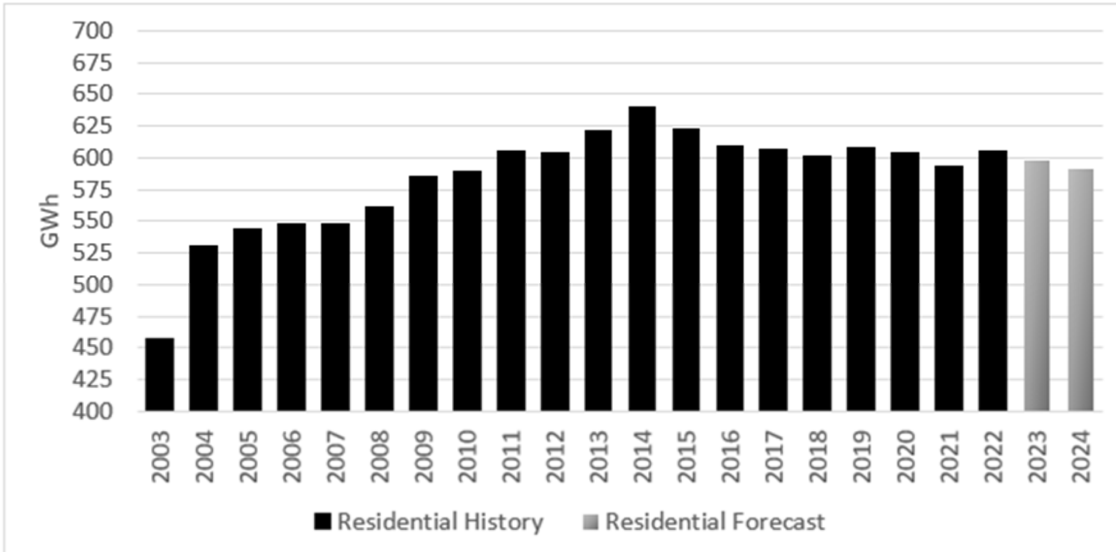
Weather is also a significant input into the 2024 sales forecast. Twenty years of historical weather was used to create the 2024 sales forecast. Weather is an input into most of the UPM models.

B. Residential

Q. WHAT ARE THE 2024 TEST YEAR FORECASTED RESIDENTIAL SALES?

A. Residential sales are forecasted to be 592 GWh. This is a decrease from 2022 weather normalized Residential sales and forecasted 2023 weather normalized Residential sales, as shown in Figure 5 below. The decline in 2024 Test Year Residential sales is consistent with the recent trend in sales for this class.

Figure 5
Weather Normalized North Dakota Residential Sales

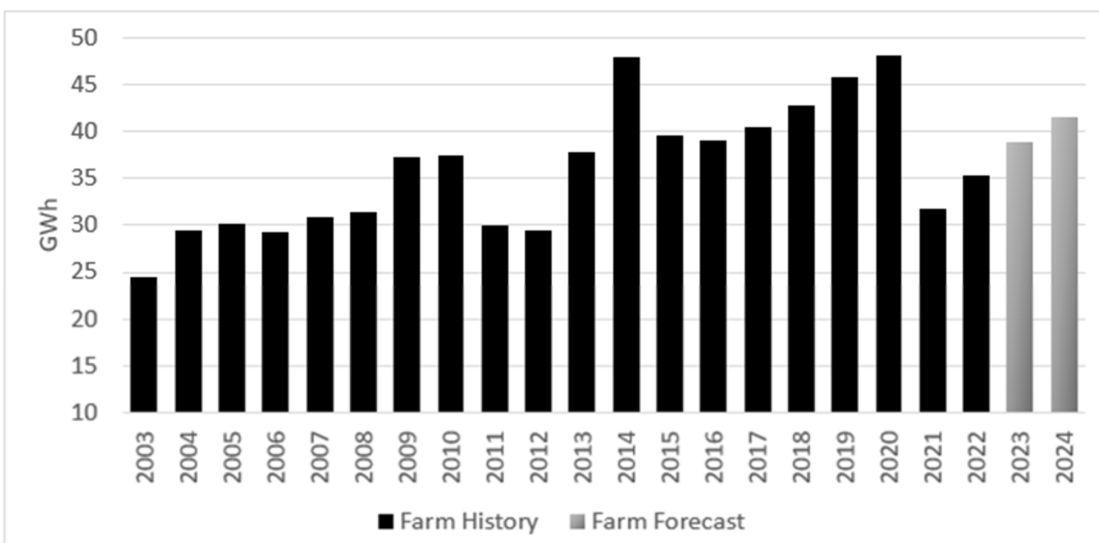


C. Farm

Q. WHAT ARE 2024 TEST YEAR FORECASTED FARM SALES?

A. Farm sales are forecasted to be 42 GWh. This is an increase over 2022 weather normalized Farm sales, as shown in Figure 6 below. It is consistent with the recent upward trend in Farm sales.

Figure 6
Weather Normalized North Dakota Farm Sales

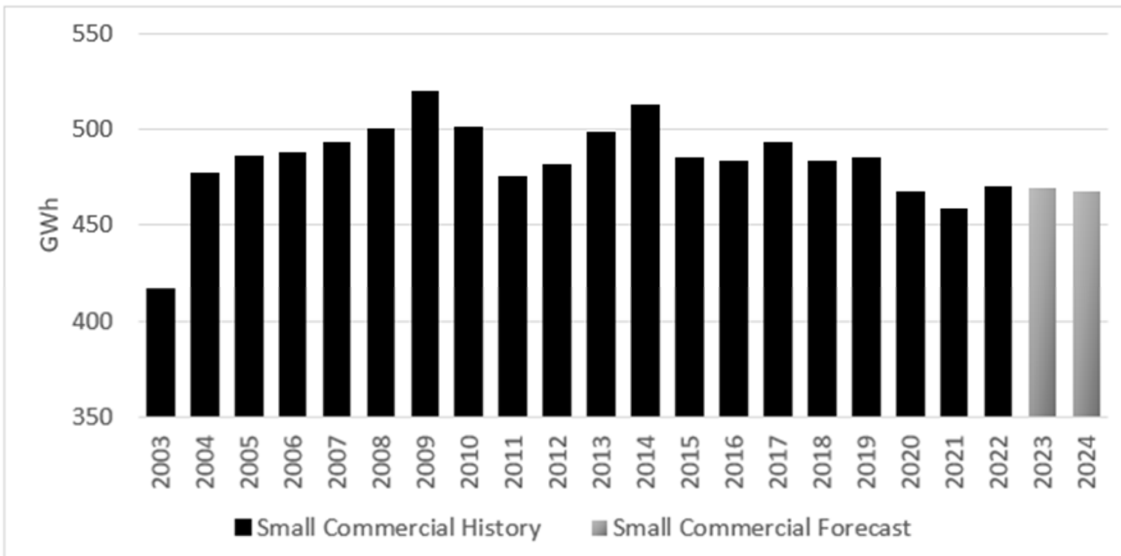


D. Small Commercial

Q. WHAT ARE 2024 TEST YEAR FORECASTED SMALL COMMERCIAL SALES?

A. Small Commercial sales are forecasted to be 467 GWh. This is a slight decrease from 2022 weather normalized Small Commercial sales, and similar to the 2023 forecasted Small Commercial sales. The 2024 Small Commercial forecast trend is consistent with the historical trend for this class, as shown in the figure below.

Figure 7
Weather Normalized North Dakota Small Commercial Sales



E. Large Commercial

Q. WHAT ARE 2024 TEST YEAR FORECASTED LARGE COMMERCIAL SALES?

A. Large Commercial sales are forecasted to be **[PROTECTED DATA BEGINS … … PROTECTED DATA ENDS]**. Large Commercial sales are a combination of statistically modeled sales and manually forecasted sales. Large Commercial sales for the 2024 Test Year, excluding manually forecasted loads (shown in the solid gray bars), are slightly lower than both the 2022 weather normalized Large Commercial sales and the 2023 forecast sales. **[PROTECTED DATA BEGINS …**

… PROTECTED DATA ENDS]. The total 2024 Large Commercial sales are forecasted to be higher than expected 2023 Large Commercial sales, as shown in Figure 8 below.

Figure 8
Weather Normalized North Dakota Large Commercial Sales

[PROTECTED DATA BEGINS…

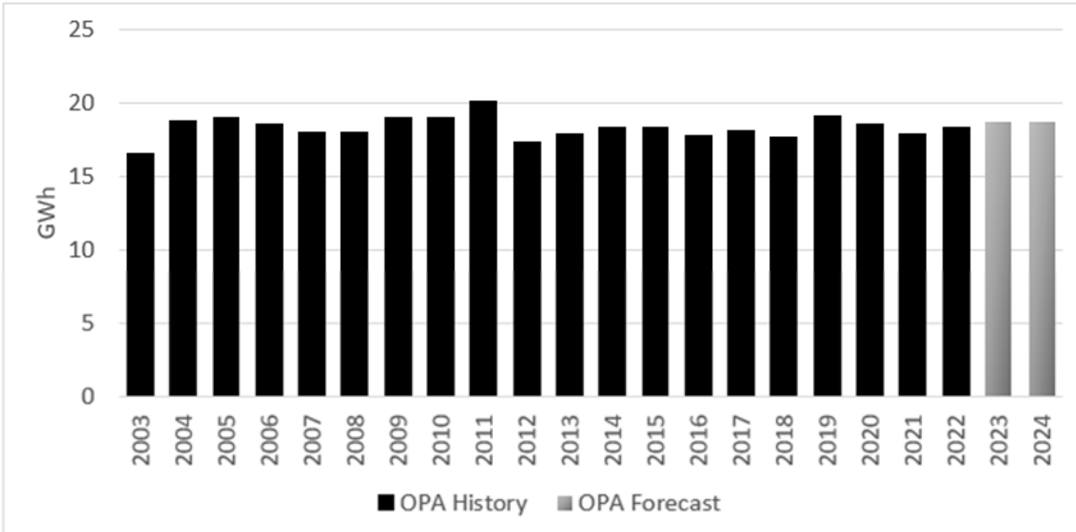
… PROTECTED DATA ENDS]

F. OPA

Q. WHAT ARE 2024 TEST YEAR FORECASTED OPA SALES?

A. OPA sales are forecasted to be 19 GWh. OPA 2024 Test Year sales are slightly higher than 2022 weather normalized OPA sales and match the expected 2023 OPA sales, as shown in the figure below.

Figure 9
Weather Normalized North Dakota OPA Sales

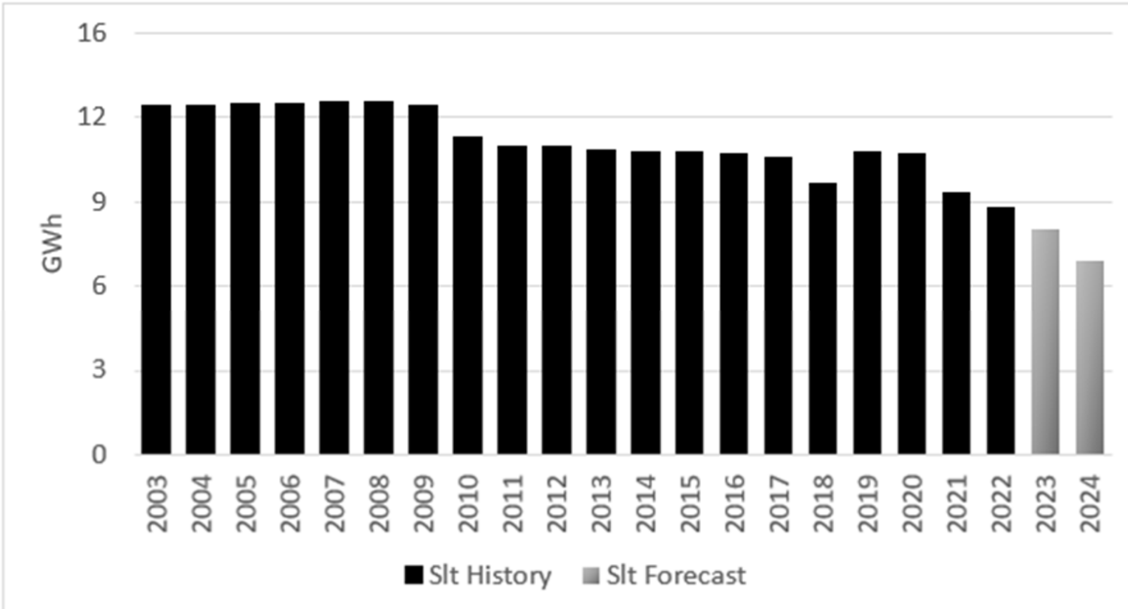


G. Street Lighting

Q. WHAT ARE 2024 TEST YEAR FORECASTED STREET LIGHTING SALES?

A. Street Lighting sales are forecasted to be 7 GWh. This is a decrease from 2022 weather normalized Street Lighting sales and expected 2023 Street Lighting sales, as shown in the figure below. The decline is due to the continued penetration of LED lights.

Figure 10
Weather Normalized North Dakota Street Lighting Sales



H. Pipeline

Q. WHAT ARE 2024 TEST YEAR FORECASTED PIPELINE SALES?

A. Pipeline sales are forecasted to be **[PROTECTED DATA BEGINS ...**
... PROTECTED DATA ENDS] This is **[PROTECTED DATA BEGINS ...**
...
PROTECTED DATA ENDS], as shown in the figure below. The sales forecast for this class represents a single customer. Economic factors are the drivers for the increase.

Figure 11
North Dakota Pipeline Sales[5]

[PROTECTED DATA BEGINS …

… PROTECTED DATA ENDS]

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[5] Pipeline sales are not weather normalized, as weather does not affect sales to this class.

TAMMY KAY MORTENSON
Fergus Falls, MN 56537
218-205-5616

Qualifications Summary

Nearly 30 years within the electric utility industry. Have served as both a coordinator and team member for many projects defining, documenting, and communicating processes to see projects to completion. Possesses a strong technical background from start in Otter Tail Power Company's Information Technology Department with further development within the Regulatory and System Operations departments

Education St. Cloud State University (St. Cloud, MN): 1992 – 1994
Bachelor of Science Degree in Business Computer Information Systems

Fergus Falls Community College (Fergus Falls, MN): 1990-1992
Associate of Arts Degree

Employment History

Otter Tail Power Company (Fergus Falls, MN) –

Senior Data Analyst — October 2022 to present
Development of Sales Forecasts and Demand Forecasts using the SAS, ITron MetrixND and Excel applications; assist with accuracy of customer usage data used as the basis for many different analysis applications

Load and Settlements Analyst — January 2022 to October 2022
Responsible for the monitoring and correcting of data collected to determine the company's portion of generation and load served within their Reliability Coordination regions to support settlement processes; monitor the accuracy of results from forecasting tools and adjust as necessary

Senior Load Management Specialist — March 2018 to January 2022
Load Management Specialist — June 2008 to September 2015
Administration of the Comverge Load Management application and supporting applications; member of the Load Management Steering Team assisting with decision-making for seasonal control strategies, develop and implement control sequences within the LMS application and provide post analysis of control events; primary support of the department's SAS applications; development and support of internal C# applications; prior implementation and administration of the eDNA data historian capturing data for several real time systems

Pricing and Tariff Administrator Analyst — June 2016 to March 2018
Responsible for maintaining the accuracy of the company's tariff sheets as filed with each state regulatory department; monitor the accuracy of customer billing; assist with regulatory filings as required; customer data analysis to assist with pricing design

Load Researcher September 2015 to June 2016
Analysis of customer usage data using the SAS application, Microsoft Excel and other applicable tools; financial calculations assisting the Accounting department with monthly closing tasks; assist with rate design and customer data analysis requests

Systems Specialist July 1999 to June 2008
Responsible for the procurement of servers and resolution of hardware issues; support of an EMC Storage Area Network; management of a VMWare virtualized environment; administration of many server applications, such as Microsoft operating systems including Active Directory, Microsoft Exchange Server and related products, Microsoft SQL Server, CaseWorks built on the Microsoft SharePoint environment, Documentum document management system, and more

Information Center Specialist Nov 1993 to Aug 1994/January 1995 to July 1999
Employed twice as an intern prior to being hired full-time within the Information Center as a member of a support call team; taught and assisted clients with the Microsoft Office software applications and performed troubleshooting on a variety of PC hardware and software problems

Skills

* Strong interpersonal skills
* Task oriented with a strong attention to detail
* Analytical and troubleshooting skills to resolve issues/tasks as quickly as possible
* Data analysis and interpretation skills for decision making purposes
* Well versed in Microsoft Office products, as well as a growing knowledgebase of SAS/SAS Enterprise Guide Analytics software, Structured Query Language (SQL) and C# programming, and ITron's MetrixND modeling application

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

OTTER TAIL POWER COMPANY SALES AND REVENUE FORECAST METHODOLOGY

November 2, 2023

TABLE OF CONTENTS

INTRODUCTION AND BACKGROUND

This filing explains OTP's process for forecasting energy sales and revenues for in its 2024 Test Year North Dakota electric rate case. Section A of this filing provides an overview of the process OTP uses to develop its sales forecast. This overview includes the methodologies employed to develop the forecasts for various rates within each class of customers. Section B provides an overview of the processes OTP uses to develop various pricing and billing determinants for its revenue forecast. This section also provides an overview of a workbook model that combines the sales forecast (section A) and the pricing and billing determinant information (section B). The workbook generates the 2024 Test Year revenue forecast. The final Section C discusses our transition from a customer based model to a meter based model.

A. SALES FORECAST

1. OVERVIEW

OTP forecasts sales for eight separate sales forecast classes, of which seven are used in the calculation of North Dakota retail rates.[1] OTP uses a sales forecast model to develop test year sales for the following North Dakota sales classes: Residential (Res); Farm (Far); Small Commercial (Scom); and Other Public Authority (OPA). Test year sales for the Pipeline (Pipe), Area Lighting (Alt) (resulting sales are added to the other relevant classes noted), and Street Lighting (Slt) classes are prepared manually, as discussed below. Test year sales for Large Commercial (Lcom) is prepared using both a statistical model and manual forecasting.

The sales forecast models use economic, weather, and usage data through December 2022.

Numerous workbooks provide all the regression models, results, and data used to create the test year forecast.

OTP used the forecasting software MetrixND (developed by Itron - https://www.itron.com) to prepare the 2024 Test Year sales forecast. Econometric models were developed by state and by sales forecast class. For the Residential, Farm, Small Commercial, and OPA classes, OTP uses MetrixND, to create sales forecasts for each class by first developing a model to forecast use-per-meter (UPM), and second, developing a model to forecast the number of meters. Total sales for these classes are equal to the forecasted UPM multiplied by the forecasted number of meters. The UPM and meter

[1] Unclassified sales, which pertains to OTP's own use of electricity, are not part of the calculation of retail rates.

models are developed for each state/class/year/month using historical sales, meter counts, economic data, weather data, and indicator variables.

Area and Street Light sales are manually forecast in Excel using a combination of factors that include: existing sales, rate of LED installations, reduction of sales due to LEDs, and maximum saturation of LED fixtures. The area light forecast is proportioned to the associated classes, and then added to the forecast of each class.

OTP does not model Pipeline customers. Pipeline pumping is a load that is very difficult to forecast using econometric models. This load is significantly impacted by world and national economic trends and federal and state energy and environmental policy.

For the Large Commercial class, OTP uses a statistical kWh model for most customers, supplemented by manual forecast of four Large Commercial customers in North Dakota.[2] These four customers are forecast based on input directly from the customers. One of the manually forecasted customers will begin receiving electric service in 2024. Another Large Commercial customer has load that is very significant and accounts for about **[PROTECTED DATA BEGINS ... ... PROTECTED DATA ENDS]** percent of OTP's North Dakota retail sales. This is a load that was added in 2022, so little history exists at this time on which to build a forecast. The third manually forecasted customer had a significant reduction in their sales in 2018, which has had a large impact on the Large Commercial class, so to accurately reflect this change, their forecast at the lower levels is excluded from the Large Commercial class kWh model and is included manually. OTP also has an existing customer that will have a significant load reduction in 2024 due to infrastructure changes; that reduction has been included manually.

OTP has worked very closely with the Pipeline and Large Commercial customers to acquire their updated projections on demand (kW) and energy (kWh).

Class sales are added together at the state level to yield the state sales. State sales are added together to produce total system sales. Table 1 provides North Dakota 2024 Test Year sales by sales forecast class.[3]

---

[2] There is also one Large Commercial customer located in South Dakota that is manually forecast.
[3] With 2024 being a leap year, all modeled forecast sales in the month of February were adjusted for 28/29 days.

Table 1
Summary of 2024 Test Year Sales Forecast
(kWh)

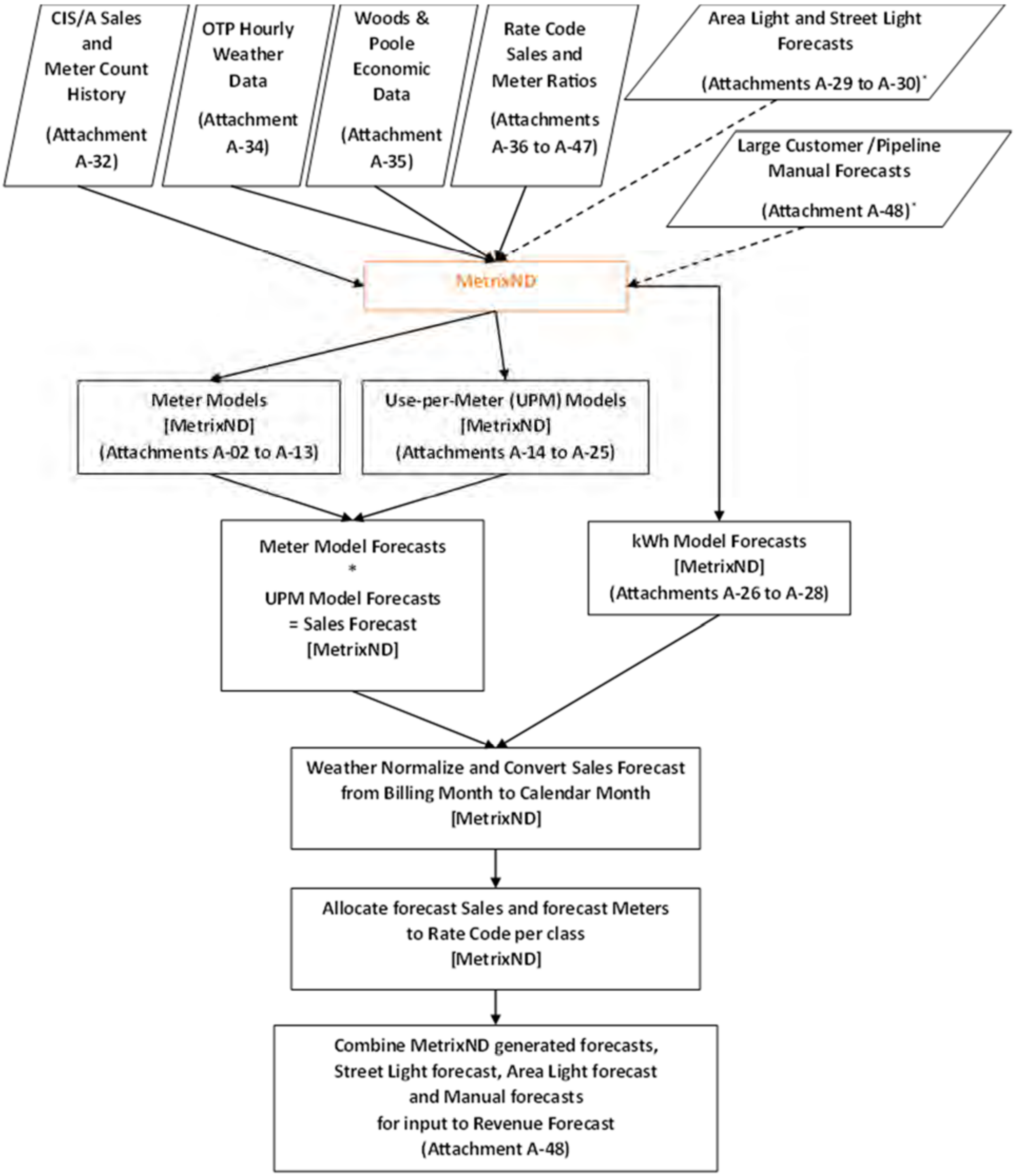
Customer Class			
Residential		591,642,942	
Farm		41,513,920	
Small Commercial		467,433,150	
Large Commercial[4]	**[PROTECTED DATA BEGINS…**		
Pipeline			**…PROTECTED DATA ENDS]**
OPA		18,713,442	
Area / Street Lighting		7,202,486	
Total Sales		**2,559,911,498**	

2. SALES MODEL DESCRIPTION

The following flowchart is the process OTP follows to create its sales forecast.

[4] Large Commercial and Pipeline sales are marked Protected Data in order to protect the sales figures for the small number of manually forecast Large Commercial and Pipeline customers.

Figure 1
Sales Forecast Flow Chart



* Forecasts are created outside of MetrixND, but are read into MetrixND to be added into the appropriate classes and/or be included in final results

a) Class Forecasts Using UPM

i. Meter Model

The meter models, designed in MetrixND, forecast monthly meter counts, by state and by class, based on twenty years of historical meter counts, economic indicators, and various indicator variables. All economic data is based on Woods and Poole Economic, Inc. 2022 databases.

The table in *Attachment A-01 Independent Variables.xlsx* shows the variables that are included in each model.

The following attachments contain all meter model and statistical information:

- *Attachment A-02 MN ResMtr.xlsx*
- *Attachment A-03 MN FarmMtr.xlsx*
- *Attachment A-04 MN SComMtr.xlsx*
- *Attachment A-05 MN OPAMtr.xlsx*
- *Attachment A-06 ND ResMtr.xlsx*
- *Attachment A-07 ND FarmMtr.xlsx*
- *Attachment A-08 ND SComMtr.xlsx*
- *Attachment A-09 ND OPAMtr.xlsx*
- *Attachment A-10 SD ResMtr.xlsx*
- *Attachment A-11 SD FarmMtr.xlsx*
- *Attachment A-12 SD SComMtr.xlsx*
- *Attachment A-13 SD OPAMtr.xlsx*

ii. UPM Model

The UPM models, also designed in MetrixND, forecast estimated monthly UPM as a function of twenty years of historical usage, weather conditions, indicator variables, and economic variables. Weather conditions are represented using monthly Heating Degree Days and Cooling Degree Days (definitions to follow), with a base of 65 degrees for cooling and 55 degrees for heating. In some cases, indicator variables are included in the equation to account for events in the historical period.

The table in *Attachment A-01 Independent Variables.xlsx* shows the variables that are included in each model.

The following attachments contain all UPM model and statistical information:

- *Attachment A-14 MN ResUPM.xlsx*
- *Attachment A-15 MN FarmUPM.xlsx*
- *Attachment A-16 MN SComUPM.xlsx*
- *Attachment A-17 MN OPAUPM.xlsx*
- *Attachment A-18 ND ResUPM.xlsx*
- *Attachment A-19 ND FarmUPM.xlsx*
- *Attachment A-20 ND SComUPM.xlsx*
- *Attachment A-21 ND OPAUPM.xlsx*
- *Attachment A-22 SD ResUPM.xlsx*

- *Attachment A-23 SD FarmUPM.xlsx*
- *Attachment A-24 SD SComUPM.xlsx*
- *Attachment A-25 SD OPAUPM.xlsx*

b) Class Forecasts of kWh

i. Large Commercial kWh Model

OTP modeled Large Commercial sales directly, rather than by developing a forecasted UPM and forecasted meter counts. The forecast sales are a function of twenty years of historical usage, weather conditions, indicator variables and economic variables. OTP utilized direct forecasting rather than a UPM approach because of a reclassification of commercial meters in the middle of the historical data. With so few meters in the Large Commercial class, reclassification to add additional meters distorted UPM data.

The table in *Attachment A-01 Independent Variables.xlsx* shows the variables that are included in the Large Commercial model.

The following attachments contain all Large Commercial kWh model and statistical information:

- *Attachment A-26 MN LComKWH.xlsx*
- *Attachment A-27 ND LComKWH.xlsx*
- *Attachment A-28 SD LComKWH.xlsx*

ii. Street Lighting Model

OTP forecasted Street Lighting sales directly to account for OTP's plans for installing LED fixtures in the near future. This will have a significant effect on the sales to this class. Historical data does not yet provide a long record upon which to base a statistical model of that effect. Therefore, OTP used a recent 12-month period that identified a share of fixtures that were LED to serve as a base year in a simulation of Street Lighting sales. The simulation assumes the following: (1) LED adoption reduces a fixture's usage by 75 percent; (2) LED installations occur from May through September each year; (3) the maximum LED share is 69 percent of fixtures; and (5) the share of LED fixtures will increase by 3.3 percent per month (during months when installations are happening). OTP forecasted the monthly LED shares using those assumptions. The forecast sales in each month is then simulated by adjusting the base year sales to account for the difference between the forecast and base-year LED shares.

The following attachment contains the Street Lighting forecast model:

- *Attachment A-29 Street Light Forecast.xlsx*

iii. Area Lighting Model

OTP provides lighting service under a variety of tariffs. This service can be street lighting, sales of which are accounted for in the Street Lighting class as mentioned above, or area lighting, which is included within the relevant customer class. For example, a Small Commercial business customer could take traditional service under Sections 10.01, 10.02 or 10.03 for the bulk of its electricity usage and have a parking lot light served under Section 11.07. All sales to that Small Commercial customer would be part of the Small Commercial class.

The Area Lighting forecast applies the expected growth rate of LED bulbs to historical data to calculate forecast values. This results in lower forecasted area lighting sales in 2024, with the shape of future sales being similar to what it was in the past, at a much lower level.

The method used to calculate an overall Area Light forecast is identical to what was used to calculate the Street Light forecast, with a slightly lower saturation level of 55% and at a lesser monthly installation rate of 2.3%.

The following attachment contains the model calculations for the Area Lighting forecast model:

- *Attachment A-30 Area Light Forecast.xlsx*

To assign the area light sales to the appropriate class, a ratio was developed using the last 24 months of area light sales. *Attachment A-31 kwh Area.xlsx* contains the data that was used to develop the ratios for each class. All calculations are done within the spreadsheet. This data is read into MetrixND and class area light sales are calculated and added to the appropriate class. *Attachment A-31 kwh Area.xlsx* contains the following data:

MNALL	MN - All area light sales summed across classes by year/month
MN_Ratios	MN - Area light monthly ratios by class
MN_Ratios_2_Yrs	MN - Two-year average ratio by class/month
NDALL	ND - All area light sales summed across classes
ND_Ratios	ND - Area light monthly ratios by class
ND_Ratios_2_Yrs	ND – Two-year average ratio by class/month
SDALL	SD - All area light sales summed across classes
SD_Ratios	SD - Area light monthly ratios by class
SD_Ratios_2_Yrs	SD – Two-year average ratio by class/month
kwh	Twenty years of area light sales for all classes in all states
MNRES	Twenty years of area light sales in the MN Residential Class
MNFARM	Twenty years of area light sales in the MN Farm Class
MNSCOM	Twenty years of area light sales in the MN Small Commercial Class
MNLCOM	Twenty years of area light sales in the MN Large Commercial Class
MNOPA	Twenty years of area light sales in the MN OPA Class
MN UNCL	Twenty years of area light sales in the MN Unclassified Class
NDRES	Twenty years of area light sales in the ND Residential Class
NDFARM	Twenty years of area light sales in the ND Farm Class
NDSCOM	Twenty years of area light sales in the ND Small Commercial Class
NDLCOM	Twenty years of area light sales in the ND Large Commercial Class
NDOPA	Twenty years of area light sales in the ND OPA Class
ND UNCL	Twenty years of area light sales in the ND Unclassified Class
SDRES	Twenty years of area light sales in the SD Residential Class
SDFARM	Twenty years of area light sales in the SD Farm Class
SDSCOM	Twenty years of area light sales in the SD Small Commercial Class
SDLCOM	Twenty years of area light sales in the SD Large Commercial Class
SDOPA	Twenty years of area light sales in the SD OPA Class
SD UNCL	Twenty years of area light sales in the SD Unclassified Class

3. MODEL INPUTS

a) Sales and Meter Count Historical Data

Data: *Attachment A-32 Sales and Meter Count History.xlsx*

Adjustments Made:

Monthly kWh data was checked for errors and corrected or adjusted due to meters not being billed, being billed twice in one month, etc. As further described below, any bill adjustments are applied to the month in which the billing error occurred. In most cases the corrections are found and downloaded during the next monthly update.

Detailed Information:

Historical kWh data and a meter count are read from statistical analysis software (SAS) Customer Information System / Analysis (CIS/A) datasets. The SAS datasets are created from extracts of OTP's Customer Information System (CIS) billing data, which are downloaded the first day of each month for the prior month. These datasets are also updated monthly for billing adjustments to appropriately reflect actual usage and billing details in the month of the original bill. Any changes made in OTP's CIS are also made in the CIS/A download, and the adjustments are made to the month the error occurred (as opposed to the month the adjustment was made). For example, if a meter has a bill adjustment made to their July bill, but the need for the adjustment was not determined or made in the CIS until December, the adjustment in the CIS/A dataset would adjust the July bill, not the December bill.

From the CIS/A dataset, the data is written into a totalized SAS dataset called cisa_allyrs. This dataset is an input in both the sales forecast and the revenue forecast. Each record in the dataset is assigned to one of five[5] classes used in the forecast. All kWh and meter counts for all classes used in the sales forecast are downloaded to the workbook referenced in this section (*Attachment A-32 Sales and Meter Count History.xlsx*). The data is divided into one of the following worksheets (tabs), one for each state and class:

- MNRes
- NDRes
- SDRes
- MNFarm
- NDFarm
- SDFarm
- MNSCom
- NDSCom
- SDSCom
- MNLCom
- NDLCom
- SDLCom
- MNOPA
- NDOPA
- SDOPA

[5] With Street Lighting manually forecast, they are handled separately from this process; Unclassified is also identified, but is not used in the sales forecast.

The variable UPM is created by dividing the monthly kWh by the monthly number of meters, for classes in which it is used.

b) OTP's Weather Data

Data: *Attachment A-33 Hourly Weather Data by Division.xlsx*

Adjustments Made:

OTP reviews hourly monitoring station temperatures each month after downloading the data. Any missing temperatures or temperatures that are clearly incorrect are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Detailed Information:

OTP used twenty years of historical weather in its 2024 sales forecast (2003-2022). This weather was collected from 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. OTP's service territory consists of 14 geographic divisions. There is one weather station in each of OTP's 14 divisions, so that the weather across OTP's entire service territory is well represented.

Attachment A-33 Hourly Weather Data by Division.xlsx contains the weather downloaded for these 14 weather stations. There is one worksheet for each weather station. The data in this spreadsheet is input into *Attachment A-34 HDD CDD By Division.xlsx* to calculate average dry bulb, Heating Degree Days (HDD), and Cooling Degree Days (CDD), for both calendar and billing month. The worksheets are as follows:

Table 2

Hourly Dry Bulb Values	
Worksheets	**Description**
FergusFallsHourlyDB	Hourly Dry Bulb/HDD/CDD for Fergus Falls Division
DevilsLakeHourlyDB	Hourly Dry Bulb/HDD/CDD for Devils Lake Division
JamestownHourlyDB	Hourly Dry Bulb/HDD/CDD for Jamestown Division
MorrisHourlyDB	Hourly Dry Bulb/HDD/CDD for Morris Division
OakesHourlyDB	Hourly Dry Bulb/HDD/CDD for Oakes Division
WahpetonHourlyDB	Hourly Dry Bulb/HDD/CDD for Wahpeton Division
LangdonHourlyDB	Hourly Dry Bulb/HDD/CDD for Langdon Division
RugbyHourlyDB	Hourly Dry Bulb/HDD/CDD for Rugby Division
CanbyHourlyDB	Hourly Dry Bulb/HDD/CDD for Canby Division
BemidjiHourlyDB	Hourly Dry Bulb/HDD/CDD for Bemidji Division
CrookstonHourlyDB	Hourly Dry Bulb/HDD/CDD for Crookston Division
HallockHourlyDB	Hourly Dry Bulb/HDD/CDD for Hallock Division
GarrisonHourlyDB	Hourly Dry Bulb/HDD/CDD for Garrison Division
MilbankHourlyDB	Hourly Dry Bulb/HDD/CDD for Milbank Division

Data: *Attachment A-34 HDD CDD By Division.xlsx*

Adjustments Made:

None.

Detailed Information:

This is built from the information in Attachment A-33. The UPM forecast uses HDD and CDD as inputs – values calculated from dry bulb temperatures in the weather data referenced above. The following is a definition of Heating and Cooling Degree Days from The National Oceanic and Atmospheric Administration (NOAA) (www.noaa.gov):

> Degree days are the difference between the daily temperature mean and 65°F. If the temperature mean is above 65°F, we subtract 65 from the mean and the result is Cooling Degree Days. If the temperature mean is below 65°F, we subtract the mean from 65 and the result is Heating Degree Days.

For each weather station, an average dry bulb temperature is calculated for each day. After determining that 55 degrees is a better fit to OTP's data for a baseline, the HDD are calculated by subtracting the average daily temperature from 55 degrees (the base). For example, if the average temperature for the day is 30 degrees, the HDD for that day is 25 (55-30). CDD are calculated by subtracting 65 (the base) from the average daily temperature. For example, if the average daily temperature is 70 degrees, the CDD for that day is 5 (70-65).

Table 3 lists each worksheet in *Attachment A-34 HDD CDD By Division.xlsx,* and its description/purpose. A brief overview of the HDD and CDD calculation follows.

Table 3

HDD CDD By Division	
Worksheets	**Description**
MNDailyAvgDB	MN Daily Average HDD and CDD, weighted by station
NDDailyAvgDB	ND Daily Average HDD and CDD, weighted by station
SDDailyAvgDB	SD Daily Average HDD and CDD, weighted by station
MNMeterSchedule	MN - Calculates Average HDD and CDD by individual billing cycle
NDMeterSchedule	ND - Calculates Average HDD and CDD by individual billing cycle
SDMeterSchedule	SD - Calculates Average HDD and CDD by individual billing cycle
MNMonthlyBilling	MN - Combines individual cycles into billing month HDD and CDD
NDMonthlyBilling	ND - Combines individual cycles into billing month HDD and CDD
SDMonthlyBilling	SD - Combines individual cycles into billing month HDD and CDD
MNBillingNormal20	MN - Combines 20 years of billing month HDD & CDD to create Normal HDD & CDD
NDBillingNormal20	ND - Combines 20 years of billing month HDD & CDD to create Normal HDD & CDD
SDBillingNormal20	SD - Combines 20 years of billing month HDD & CDD to create Normal HDD & CDD
MNMonthlyCalendar	MN - Combines calendar month HDD and CDD
NDMonthlyCalendar	ND - Combines calendar month HDD and CDD
SDMonthlyCalendar	SD - Combines calendar month HDD and CDD
MNCalendarNormal20	MN - Combines 20 years of calendar month HDD & CDD to create normal HDD & CDD
NDCalendarNormal20	ND - Combines 20 years of calendar month HDD & CDD to create normal HDD & CDD
SDCalendarNormal20	SD - Combines 20 years of calendar month HDD & CDD to create normal HDD & CDD

To determine the HDD and CDD for North Dakota, the weather stations in North Dakota are weighted by sales and summed.

ND Daily Heating Degree Days=
[(Station 2 Sales/Total ND Sales)*Station 2 HDD]+
[(Station 3 Sales/Total ND Sales)*Station 3 HDD]+
[(Station 5 Sales/Total ND Sales)*Station 5 HDD]+
[(Station 6 Sales/Total ND Sales)*Station 6 HDD]+
[(Station 7 Sales/Total ND Sales)*Station 7 HDD]+
[(Station 8 Sales/Total ND Sales)*Station 8 HDD]+
[(Station 11 Sales/Total ND Sales)*Station 11 HDD]+
[(Station 13 Sales/Total ND Sales)*Station 13 HDD]

ND Daily Cooling Degree Days=
[(Station 2 Sales/Total ND Sales)*Station 2 CDD]+
[(Station 3 Sales/Total ND Sales)*Station 3 CDD]+
[(Station 5 Sales/Total ND Sales)*Station 5 CDD]
[(Station 6 Sales/Total ND Sales)*Station 6 CDD]+
[(Station 7 Sales/Total ND Sales)*Station 7 CDD]+
[(Station 8 Sales/Total ND Sales)*Station 8 CDD]+

[(Station 11 Sales/Total ND Sales)*Station 11 CDD]+
[(Station 13 Sales/Total ND Sales)*Station 13 CDD]

This process is repeated for Minnesota and South Dakota.

OTP creates HDD and CDD based on billing month weather and calendar month weather. The process is as follows:

1. *Billing Month HDD and CDD:*
   Daily HDD and CDD are added by billing cycle to determine the HDD and CDD for each cycle and month. Once we have an HDD and CDD value for each cycle and month, all the cycles are combined into one billing month, averaging the cycle HDD and the cycle CDD. A HDD value and a CDD value for each billing month have now been created.

   Next, we calculate Normal Billing HDD and CDD. **These values are used in the sales forecast model.** They are calculated by averaging 20 years of monthly billing HDD and CDD.

2. *Calendar Month HDD and CDD:*
   Daily HDD and CDD are added by calendar month to calculate the HDD and CDD for each calendar month.

   Normal Calendar HDD and CDD are next calculated. **These values are used in the sales forecast.** They are calculated by averaging 20 years of monthly Calendar HDD and CDD.

OTP's sales forecast uses weather normalization principally to compare the sales forecast to weather normalized historical data. HDD and CDD are used in all models with the exception of street and area lighting. All of OTP's classes have some level of weather sensitivity.

c) Woods & Poole Economics, Inc.

Data: *Attachment A-35 Woods and Poole Data.xlsx*

Adjustments Made: None

Detailed Information:

OTP uses economic data from Woods & Poole Economics, Inc. in its sales forecasts. Woods & Poole's database contains economic and demographic data. OTP downloads this information by county for use in its meter and UPM models.

OTP does not serve the entire load in the counties within its service territory, which is especially problematic when OTP does not serve a large city (e.g. Fargo, Moorhead, Grand Forks and Minot) that has a significant impact on the economy of the county. OTP does not serve these larger cities, but it does serve small communities surrounding these larger cities. To reflect this fact, OTP used econometric data only from counties where OTP serves at least 10 percent of the population of the county. County population data is downloaded from www.census.gov. The percentage of the population served by OTP in each county was determined by dividing the sum of populations of towns served by OTP in each county by the total population of the county. Town populations were obtained from an internal database of towns served. The data is then summed to the state level and graphed as a reasonability check. Annual Woods & Poole data is converted from annual data to monthly data by interpolating between annual values with a flat line.

As OTP serves three states with economic differences, using econometric models makes it possible to utilize the different economic data for each state and determine whether particular variables are drivers for each state.

4. CALENDAR MONTH CALCULATION

Because historical usage data is, in its purest form, in billing month format, OTP created all models using billing month data. After creating billing month sales models, these models were adapted to calendar month by substituting billing month days with the calendar month days. As weather generally only affects UPM or kWh, not the number of meters, the calendar month conversion is only applied to the UPM or kWh models. To create the calendar month UPM or kWh forecasts, the calendar month HDD and CDD (from *Attachment A-34 HDD CDD By Division.xlsx*) are substituted for the billing month HDD and CDD resulting in a calendar month UPM or kWh forecast.

5. INDICATOR VARIABLES

All sales forecast models utilize indicator variables. Monthly indicator variables that account for seasonal differences are the most common. Annual indicator variables are used to account for the deviations in growth or consumption that are not expected in the test year. For example, the Residential UPM Model uses a indicator variable starting in 2011 to account for the change from a growth trend that occurred prior to a slow decline occurring after 2010. Other indicator variables were utilized as necessary to improve the fit of the model and statistical significance of the economic and weather variables. Trend variables were also used to predict sales where they were significant.

6. USE OF SALES FORECAST IN REVENUE FORECAST

As noted earlier, OTP develops sales forecasts for each class within each jurisdiction. However, to develop an accurate revenue forecast, the sales forecasts need to be allocated to a more detailed rate code level. In this manner, OTP can apply appropriate billing determinants to compute the forecasted revenues. With the Large Commercial class forecast using a kWh sales model, rather than a UPM and meter model, the forecasted meter counts for this class is created using an exponential smoothing model within MetrixND using historical meter data. Meter counts for manually forecast customers are manually added to the class meter totals. Meter counts are not required for the Area or Street Lighting classes as revenue for these classes is determined on a per fixture basis. More detail can be found in the Revenue Forecast section at B.3.b).

To allocate the forecasted sales and meters to each rate code, the most current 24 months of billing sales and meter counts for each state/year/month/revenue class/rate code and state/year/month/revenue class are summed and input into separate Excel spreadsheets for each class. A percent for each rate code in each class is calculated by state/year/month, then a two-year average of these percentages is computed.

See *Attachment A-36 Res Sales by Rate Code.xlsx* as an example of this process. The worksheets contained in this spreadsheet are found in Table 4:

Table 4

Res Sales to Rate Code	
Worksheet	**Description**
MN / ND / SD	Two years of sales by rate code, by month
MN Ratios / ND Ratios / SD Ratios	Two years of ratios per rate code, by month
MN_2_Year_Ratios / ND_2_Year_Ratios / SD_2_Year_Ratios	Average percentage of sales by month, rate code (assigned to a indicator year)
Res_Calendar Forecast	2024 monthly calendar forecast by month
Res_Calendar by Rate Code	2024 monthly calendar forecast by month, rate code

This same process is followed for each of the following classes for all kWh sales and meter counts: Residential, Farm, Small Commercial, Large Commercial and OPA. These monthly percentages are then applied to the sales and meter forecasts to allocate sales and meter counts to the rate code level.

The following attachments create the monthly sales and meter forecasts by rate code:

- *Attachment A-36 Res Sales to Rate Code.xlsx*
- *Attachment A-37 Res Meters to Rate Code.xlsx*
- *Attachment A-38 Farm Sales to Rate Code.xlsx*
- *Attachment A-39 Farm Meters to Rate Code.xlsx*
- *Attachment A-40 SCom Sales to Rate Code.xlsx*
- *Attachment A-41 SCom Meters to Rate Code.xlsx*
- *Attachment A-42 LCom Sales to Rate Code.xlsx*
- *Attachment A-43 LCom Meters to Rate Code.xlsx*
- *Attachment A-44 OPA Sales to Rate Code.xlsx*
- *Attachment A-45 OPA Meters to Rate Code.xlsx*

A similar process is used to create monthly rate code allocations for Street Light and Area Light sales using the most current 24 months of billing data. These monthly percents are then applied to the sales forecasts to allocate sales to the rate code level. Area Light sales are then added to their respective class totals. A set of worksheets for each class, similar to the Res sales example above, can be found in the following attachments:

- *Attachment A-46 ALT Sales to Rate Code.xlsx*
- *Attachment A-47 SLT Sales to Rate Code.xlsx*

This process is not necessary for the Pipeline class, as its sales and meter counts are manually added to the applicable rate code forecast.

The kWh sales forecast and meter count forecast at the rate code level are key inputs into the revenue forecast model for pricing.

The output of the sales forecast, including a meter count forecast, is found in *Attachment A-48 Sales and Meter Count Forecasts to Revenue Forecast.xlsx*. This workbook contains four worksheets. The first, titled *Sales Input to Revenue Forecast*, contains the entire non-company use sales forecast, by state and rate code. It includes the manually forecasted customers' sales. The next worksheet, *Meter Input to Revenue Forecast* contains the forecast of meter counts, by state and rate code, including manually forecasted customer meter counts. The next tab, *Manually Forecasted Customers*, contains the manually forecasted customer sales data. The Pipeline data within these worksheets goes into the revenue model to be priced separately. Finally, the last worksheet, *Unclassified* contains OTP's forecasted company use sales.

B. REVENUE FORECAST

1. OVERVIEW

Section B is a description of the process used to develop OTP's revenue forecast. The revenue forecast used up to three years of historical customer data from CIS/A and Excel workbooks containing OTP's current rate code prices, one contains light rates and the other contains all other rates. There are also four SAS programs and numerous Excel workbooks attached that provide the inputs and a transparent view of OTP's revenue model.

OTP developed its revenue forecast[6] by applying rate code pricing to the applicable billing determinants[7] derived from the sales forecast. OTP uses actual historical billing

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[6] OTP forecasts retail revenue excluding small power producers.
[7] Billing Determinants are units needed for billing. OTP's billing determinants used in the revenue forecast include sales (kWh), demand (kW), ratcheted demand (ratcheted kW), and meter count.

determinants to develop demand ratios, ratcheted demand[8] ratios, and forecasted meter counts. The demand and ratcheted demand ratios are multiplied by the sales forecast to acquire the demand and ratcheted demand for each rate code. When all billing determinants at the rate code level were computed, they were multiplied by the corresponding price to compute revenues for each rate code. Subsequently, OTP rolled up the rate code level revenues to their respective cost of service class level revenues by state.

The cost of service classes are as follows:

- Residential
- Farms
- Small General Service
- Large General Service
- Irrigation
- Outdoor Lighting
- Other Public Authority (OPA)
- Controlled Service Water Heating/Deferred Load
- Controlled Service Interruptible
- Controlled Services Off Peak

Section B of this document will cover the information needed to develop the North Dakota revenue forecast.

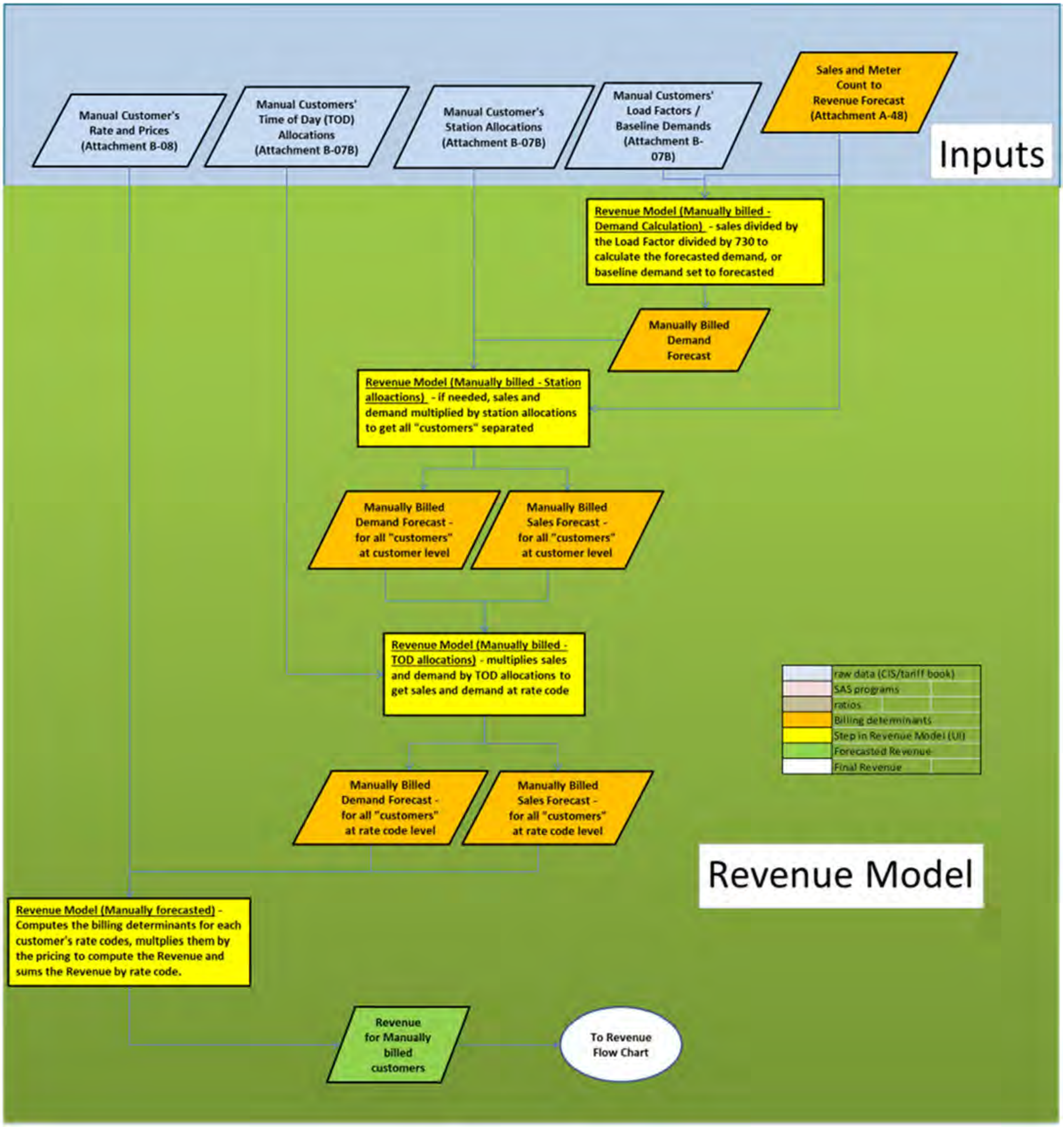
2. REVENUE FORECAST DESCRIPTION

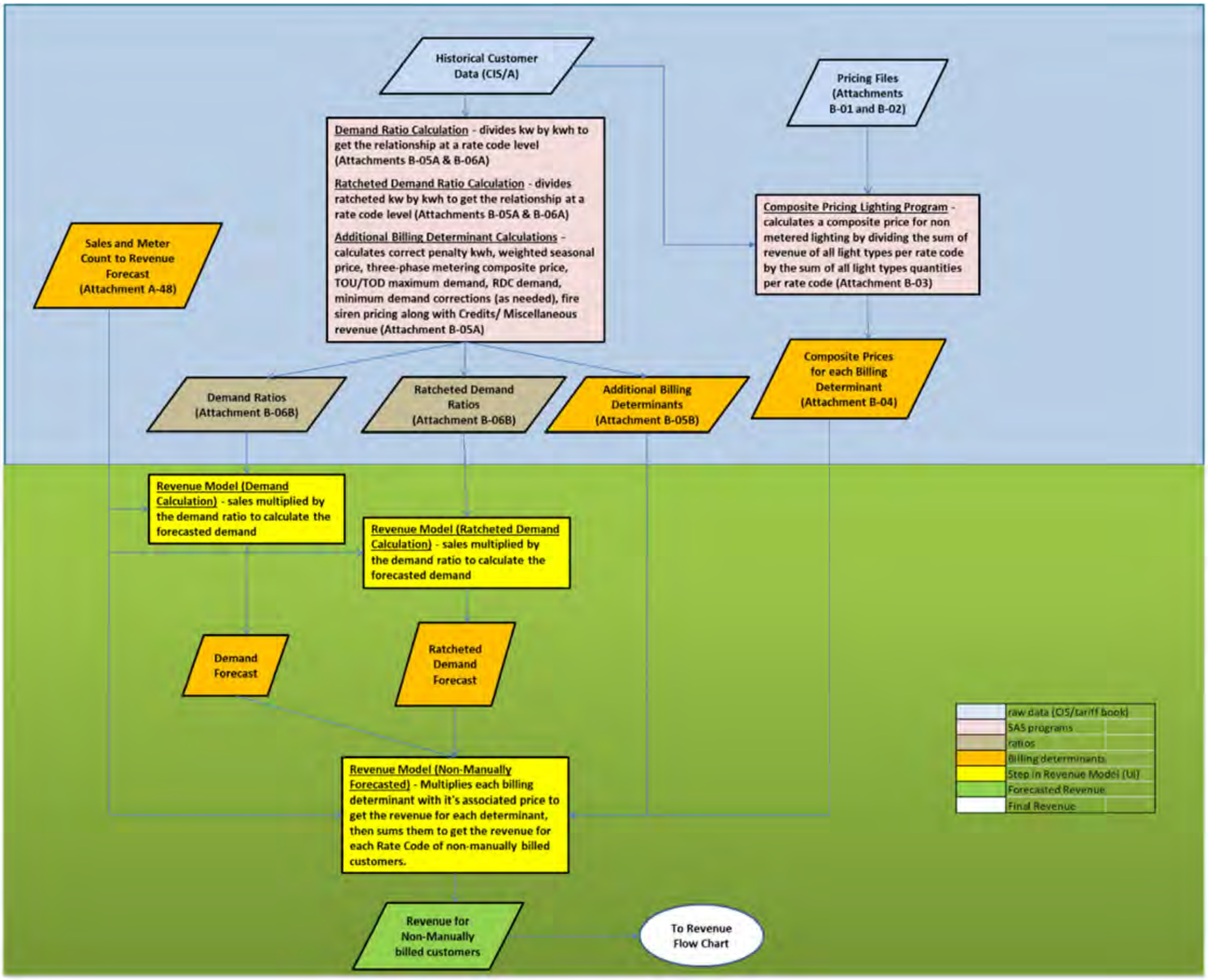
The following flowcharts describe the process OTP used to create its revenue forecast. The remainder of section B of this document is laid out in two main sections: Inputs and Revenue Model.

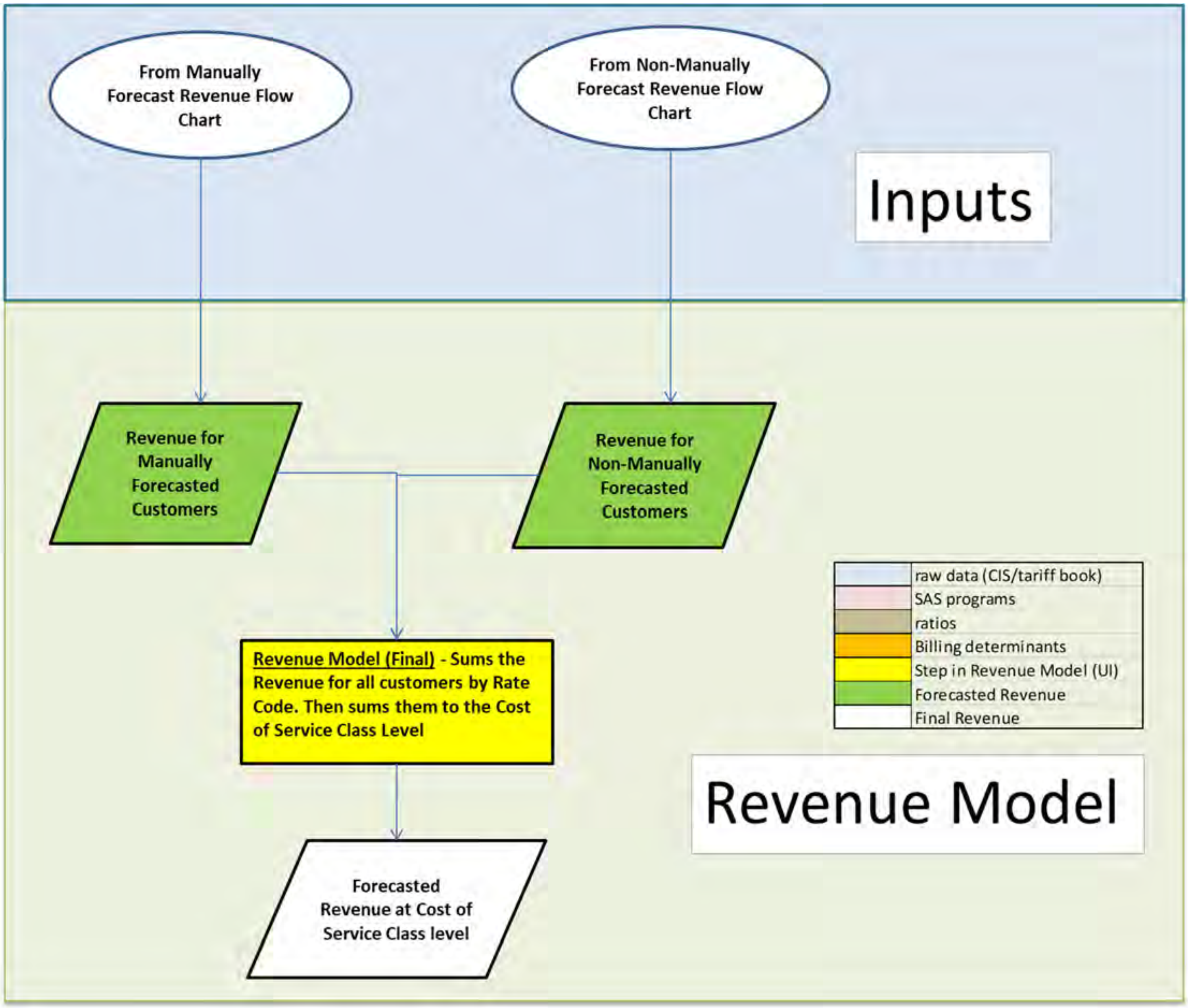
Inputs: This section explains how each input to the revenue model is calculated. The initial sections of each input can be read alone, or you can use the SAS sections as a companion to the SAS programs, which are attached in pdf format.

Revenue Model: This section is a description of OTP's revenue model and is the link between the inputs and the final revenue forecast results.

[8] Ratcheted demand is the maximum demand over the last 12 months, primarily used for calculating the facilities demand.


Manual Customer's Rate and Prices (Attachment B-08)
Manual Customers' Time of Day (TOD) Allocations (Attachment B-07B)
Manual Customer's Station Allocations (Attachment B-07B)
Manual Customers' Load Factors / Baseline Demands (Attachment B-07B)
Sales and Meter Count to Revenue Forecast (Attachment A-48)
Inputs
Revenue Model (Manually billed - Demand Calculation) - sales divided by the Load Factor divided by 730 to calculate the forecasted demand, or baseline demand set to forecasted
Manually Billed Demand Forecast
Revenue Model (Manually billed - Station alloactions) - if needed, sales and demand multiplied by station allocations to get all "customers" separated
Manually Billed Demand Forecast - for all "customers" at customer level
Manually Billed Sales Forecast - for all "customers" at customer level
Revenue Model (Manually billed - TOD allocations) - multiplies sales and demand by TOD allocations to get sales and demand at rate code
raw data (CIS/tariff book)
SAS programs
ratios
Billing determinants
Step in Revenue Model (UI)
Forecasted Revenue
Final Revenue
Manually Billed Demand Forecast - for all "customers" at rate code level
Manually Billed Sales Forecast - for all "customers" at rate code level
Revenue Model
Revenue Model (Manually forecasted) - Computes the billing determinants for each customer's rate codes, multplies them by the pricing to compute the Revenue and sums the Revenue by rate code.
Revenue for Manually billed customers
To Revenue Flow Chart


Historical Customer Data (CIS/A)
Pricing Files (Attachments B-01 and B-02)
Demand Ratio Calculation - divides kw by kwh to get the relationship at a rate code level (Attachments B-05A & B-06A)
Ratcheted Demand Ratio Calculation - divides ratcheted kw by kwh to get the relationship at a rate code level (Attachments B-05A & B-06A)
Additional Billing Determinant Calculations - calculates correct penalty kwh, weighted seasonal price, three-phase metering composite price, TOU/TOD maximum demand, RDC demand, minimum demand corrections (as needed), fire siren pricing along with Credits/ Miscellaneous revenue (Attachment B-05A)
Composite Pricing Lighting Program - calculates a composite price for non metered lighting by dividing the sum of revenue of all light types per rate code by the sum of all light types quantities per rate code (Attachment B-03)
Sales and Meter Count to Revenue Forecast (Attachment A-48)
Demand Ratios (Attachment B-06B)
Ratcheted Demand Ratios (Attachment B-06B)
Additional Billing Determinants (Attachment B-05B)
Composite Prices for each Billing Determinant (Attachment B-04)
Revenue Model (Demand Calculation) - sales multiplied by the demand ratio to calculate the forecasted demand
Revenue Model (Ratcheted Demand Calculation) - sales multiplied by the demand ratio to calculate the forecasted demand
Demand Forecast
Ratcheted Demand Forecast
Revenue Model (Non-Manually Forecasted) - Multiplies each billing determinant with it's associated price to get the revenue for each determinant, then sums them to get the revenue for each Rate Code of non-manually billed customers.
Revenue for Non-Manually billed customers
To Revenue Flow Chart
raw data (CIS/tariff book)
SAS programs
ratios
Billing determinants
Step in Revenue Model (UI)
Forecasted Revenue
Final Revenue


From Manually Forecast Revenue Flow Chart
From Non-Manually Forecast Revenue Flow Chart
Inputs
Revenue for Manually Forecasted Customers
Revenue for Non-Manually Forecasted Customers
raw data (CIS/tariff book)
SAS programs
ratios
Billing determinants
Step in Revenue Model (UI)
Forecasted Revenue
Final Revenue
Revenue Model (Final) - Sums the Revenue for all customers by Rate Code. Then sums them to the Cost of Service Class Level
Revenue Model
Forecasted Revenue at Cost of Service Class level

3. INPUTS

Several inputs to the revenue model are necessary in order to calculate the revenue forecast. They include: (1) forecasted sales; (2) composite pricing for lighting; (3) demand ratios; (4) ratcheted demand ratios, (5) additional billing determinants, (6) forecasted meter counts; and (7) manually forecasted customer inputs.

a) Forecasted Sales

The sales forecast[9] described above in section A is the foundation for the revenue forecast. The sales forecast is provided at the rate code level by state for all non-manually forecasted customers. Once the state/month/rate code level forecasted sales were computed (see section A.6.), they were input into the revenue model. The manually forecasted customers' sales were also input into the revenue model, however at the customer level.

b) Composite Pricing (CP) for Lighting

To compute the revenue forecast for lighting, allocation of the sales forecast to rate code level is necessary, due to different types of fixtures per rate code (*Attachment A-48 Sales Forecast to Revenue Forecast.xlsx*). To develop actual pricing derived by rate design, the rate codes were allocated to their most granular level of fixture types per rate code.

Consequently, to compute each rate code's revenue forecast, each rate code needs a weighted composite rate to price the sales at the rate code level. Since OTP is converting lighting fixtures from non-LED to LED, OTP uses the frequencies of fixture kinds to compute the composite rates based on the most current calendar month of CIS/A data, starting at a customer level and building up to rate code level based on each customer's fixture type(s), fixture replacement allocations and fixture kWh allocations. OTP used one full calendar year of historical data to reflect the usage trends of current lighting customers with kWh charges. This program excludes the manually forecasted customers from the sales forecast and the non-lighting customers from the CP process.

This program excludes the manually forecasted customers from the sales forecast.

The CP Lighting SAS program develops the following composite billing determinants:

- fixture charges (N730, N741, N749)
- kWh charges (N408, N744, N748)
- fixture counts (N730, N741, N749)
- kWh sales (N408, N744, N748)

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[9] Calendar month sales are used to compute the Revenue Forecast.

The SAS program and Excel workbook that create the composite rates (*Attachment B-03 Annual_Lighting_Counts.pdf* and *Attachment B-04 Composite Pricing_Lighting.xlsx*) is described in more detail below.

SAS Program: CP Lighting

The CP Lighting program (*Attachment B-03 Annual_Lighting_Counts.pdf)* imports one year of customer billing data from the CIS/A database. We assign rate code fixtures to each customer based on their rate code and fixture counts. All manually forecasted customers are excluded from the customer billing data. The Excel workbooks *Attachment B-01 Rates.xlsx and Attachment B-02 Light Rates.xlsx* contain the pricing and is used to determine what billing determinants are needed to calculate the revenue for each rate. From this, the program determines any necessary tier thresholds and splits the kWh or fixture counts accordingly. The program uses one year of customer data and was summed by state/month/rate code/fixture type, as well as by state/month/rate code. The billing determinants for each fixture type were then multiplied by the appropriate fixture's pricing schedule. Then the total one-year revenue for each determinant was divided by the corresponding rate code determinant resulting in the weighted rate code price. OTP sums the weighted fixture price to the rate code level composite price, exports them from the SAS program and includes them in *Attachment B-04 Composite Pricing_Lighting.xlsx*. These prices are imported into the revenue model.

c) Demand Ratios

The Business Planning Department provides a kWh sales forecast for each rate code. For pricing purposes we also need to compute a forecasted demand amount. Using SAS (*Attachment B-05A Billing Determinant Ratio Calculations_Not_Public.pdf)*, a ratio is developed at a state/month level to relate historical kWh to kW. The demand ratio is determined based on three years of CIS/A data, starting at the customer level and building up to rate codes, regardless of their revenue class. This still allowed OTP to factor in some degree of weather normalization. The forecasted demand is calculated, via SAS (*Attachment B-06 Demand_Ratcheted Demand_ratio_Not_Public.pdf),* by multiplying the forecasted sales by the calculated ratio per state/month/rate code. The manually forecasted customers from the sales forecast are handled differently and are excluded from these programs. The details within the SAS program for the Demand Ratios is described in more detail below.

SAS Program: Demand Ratios

The SAS program, *Attachment B-05A Billing Determinant Ratio Calculations_Not_Public.pdf*, imports three years of individual customer historical data and assigns each customer to a rate code. It also imports *Attachment B-01 Rates.xlsx* to determine if kW is needed for billing and if there is a minimum kW. The manually forecasted customers are excluded from this program. If a customer is on the Residential Demand Control (RDC) rate, then the ratcheted kW is set to the kW, since the billing demand is a coincident demand and functions like a ratcheted kW. If a rate requires kW, the actual kW is compared to the minimum kW, and the greater of the two is used in the customer's bill. This is needed since the CIS/A data records actual (not billing) kW, and for pricing we need to have the entire amount of billing kW. The kWh and kW are summed by state/year/month/rate code for three calendar years of data. The summed kW is then divided by the summed kWh to get the demand ratios for each state/year/month/rate code. Once we have every year's ratios, the average ratio is found and exported from the SAS program (*Attachment B-005B Billing Determinant Ratios_ND_Not_Public.xlsx*). With the Irrigation rate having highly fluctuating customer counts in the months from November through April, the average of the other months is found and applied to these months. The rate code level demand ratios are imported into the revenue model.

d) Ratcheted Demand Ratios

Along with the kWh and kW, ratcheted kW is also needed for pricing. Using the same SAS program that is used to calculate the demand ratios, (*Attachment B-05A Billing Determinant Ratio Calculations_Not_Public.pdf)*, a ratio is developed at the state/month level to relate historical kWh to ratcheted kW. It is based on three years of CIS/A data, starting at a customer level, and building up to rate codes regardless of revenue class combination. This still allowed OTP to factor in weather normalization. The forecasted ratcheted demand is calculated, via SAS (*Attachment B-06 Demand_Ratcheted Demand_ratio_Not_Public.pdf),* by multiplying the forecasted sales by the calculated ratcheted demand ratio per state/month/rate code. The manually forecasted customers from the sales forecast are handled differently and are excluded from these programs. The SAS program for the Ratcheted Demand Ratios is described in more detail below.

SAS Program: Ratcheted Demand Ratios

The SAS program imports three years of individual customer historical data and assigns each customer to a rate code. *Attachment B-01 Rates.xlsx* is also imported to determine if the ratcheted kW is needed for billing (primarily used for calculating the facilities charge) and if there is a minimum ratcheted kW. The manually forecasted customers are excluded from this program. If any rate requires a ratcheted kW, the ratcheted kW is compared to the minimum kW, and the greater of the two is used in the customer's bill. This is needed since the CIS/A data records actual (not billing) kW, and for pricing we need to have the entire amount of billing kW. Due to the ratcheted kW being the maximum kW over a 12-month period, the maximum kW for all rate codes on a Time of Use (TOU)/Time of Day (TOD) rate must be found and the others deleted. Therefore, if a customer is on a TOU/TOD rate, the maximum ratcheted kW is found among the multiple rate codes for each customer's monthly bill.

Once we have the maximum for each customer's monthly bill, if the corresponding rate code's ratcheted kW for that month is not the max, it is set to zero. Then the kWh and ratcheted kW are summed by state/month/rate code for reporting purposes. The kWh and ratcheted kW are summed by state/year/month/rate code for three calendar years of data. The summed ratcheted kW is divided by the summed kWh to get the ratcheted demand ratios for each state/year/month/rate code. Once we have every year's ratio, the average ratio is found and exported from the SAS program (*Attachment B-005B Billing Determinant Ratios_ND_Not_Public.xlsx*) to be imported into the revenue model.

e) Additional Billing Determinant Calculations

Some additional billing determinants are needed for the final revenue calculation in order to determine the correct prices or calculate accurate revenue. *Attachment B-05A Billing Determinant Ratio Calculations_Not_Public.pdf* provides the calculations for these determinants and Attachment B-05B Billing Determinant Ratios_ND_Not_Public.xlsx contains the results. They are listed below with detailed descriptions to follow.

- (1) Penalties
- (2) Seasonal Charges
- (3) Three-Phase Metering
- (4) Time of Use/Time of Day Rates (TOU/TOD)
- (5) Residential Demand Control Demand
- (6) Minimum Billing Demand/Facilities Demand
- (7) Fire Sirens
- (8) Credits/Miscellaneous

(1) Penalties

Rates for certain customers, such as large and small dual fuel customers, include penalty rates that are assessed when there is measured usage during a period in which the customer is intended to fully shed its load. This could happen when the customer's system fails to respond to a control signal and/or completely shed its load when control is initiated. These customers have a separate penalty register on their meters, so if the customer has usage during the penalty period, the kWh is counted on both the regular register and the penalty register and the data stored in the CIS system for billing purposes.

Adding both kWh values would result in double-counting the total kWh. Therefore, we first subtract the penalty kWh value from the regular kWh value to determine the appropriate kWh to charge at the standard (non-penalty) price. Since the kWh on the penalty meter is charged at the standard price as well as the penalty price, we add the standard rate price to the penalty rate price in *Attachment B-01 Rates.xlsx* before calculating the penalty kWh price.

(2) Seasonal Charges

There are various rates where customers have the option for seasonal usage. This allows customers to receive a bill only in the months they are active, rather than all year. To recover the customer charges that the customer would incur during their inactive months, a seasonal charge is applied to their first bill each year. The pricing workbook (*Attachment B-01 Rates.xlsx*) is used to determine if a seasonal charge is applicable to each rate. If it is, the first bill for each of the seasonal customers is found, and for each month the number of first bills is counted by state/month/rate group/rate code. The number of customers on any rate is counted by state/month/rate group. The number of seasonal customers for each rate code is divided by the number of all customers in that state/month/rate group level to get the percentage of seasonal customers with their first bill in each month. That percentage is then multiplied by the fixed seasonal charge to get the weighted seasonal price for each month and is exported with the other weighted prices. This is added to the customer charge weighted price before it is imported into the revenue model.

(3) Three-Phase Metering

OTP's Farm rate has a facility charge that is based on either single-phase metering or three-phase metering. *Attachment B-01 Rates.xlsx* is used to determine if three-phase charges are applicable. Using three years of historical data, all three-phase service customers are counted by state/month/rate group/rate code/tier. In addition, a count of all customers (single-phase and three-phase) is determined by state/month/rate group/rate code. The three-phase customer count is multiplied by the corresponding price and then divided by the total customer count for the rate code. This is the composite rate that will be used in the final revenue forecast calculation.

(4) Time of Use/Time of Day Rates

TOU/TOD rates have differing rates based on the time of the customer's usage. Because the TOU/TOD rates have multiple registers on their meter, one for each TOU/TOD rate code, and all the registers together account for the total usage for a single day. The ratcheted demand, which is needed in order to calculate the facilities demand, needs to be the maximum of the multiple registers. For each customer, we determine the maximum ratcheted kW for each division/premise/bill date/meter number.[10] If the ratcheted kW does not equal the maximum ratcheted kW for each rate code, it is set to zero, leaving only the maximum ratcheted kW. A variable is created to identify if the ratcheted kW was set to zero so that it will not be overridden when the minimum demand is applied, described below (Minimum Billing Demand/Facilities Demand).

(5) Residential Demand Control Demand

Customers on the RDC rate have their ratcheted kW set to the billing kW, since the billing demand functions like a ratcheted kW.

(6) Minimum Billing Demand/Facilities Demand

OTP has several rates where a minimum demand is required. *Attachment B-01 Rates.xlsx* is input to identify what the minimum kW or ratcheted kW is for each rate code, if any. If the actual kW or ratcheted kW is less than this minimum requirement, the actual kW or ratcheted kW is replaced by the minimum required amount.[11] This is necessary because CIS/A data contains actual kW and ratcheted kW, not billing kW or billing ratcheted kW.

(7) Fire Sirens

The Fire Sirens price is based on horsepower (HP) rather than kWh. These are set up in CIS as area light types, and a separate type is created for each HP. Thus, in *Attachment B-02 Light Rates.xlsx,* each siren size has its own price with the customer charge added to the per HP amount since the customer charge is by siren. These are handled below in section (8) Credits/Miscellaneous.

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[10] That calculation must occur at the meter level because it is possible for a customer to have multiple TOU/TOD rates, however for each rate sequence (ex. M611) the meter number is the same followed by a suffix – which for this program's purposes are deleted.

[11] Only the maximum TOU/TOD rate code for the ratcheted kW are included to avoid overriding the non-maximum ratcheted kW being set to zero on page 28, section (4) Time of Use/Time of Day (TOU/TOD) Rates.

(8) Credits/Miscellaneous

OTP has rates and credits that are not based on metering consumption. They are the Air Conditioning credit, Water Heating credit, Closed Non-Standard Lighting, Fire Sirens and Tail*W*inds (wind energy). Since these rates are not directly based on metered kWh, they are handled differently in the program. The program identifies customers on these rates and sums up the quantity by state/month/rate code of three years of historical data. To get the quantity for Tail*W*inds, the kWh is first divided by 100 since the price they pay is per 100 kWh. The total quantity by state/month/ rate code is multiplied by the price for that rate code to get the total revenue for that rate code. Once we have the total Credits/Miscellaneous revenue it is exported from the SAS program and imported into the revenue model and added to the calculated revenue for the non-manually forecasted customers.

f) Meter Count Forecast

A meter count is needed to calculate the fixed charges such as a fixed facilities charge, seasonal charge or customer charge. OTP forecasts meter counts, excluding manually forecasted customers, for each state/class/year/month within MetrixND using a combination of historical meter counts, economic data and indicator variables as described in detail in Sections A.2. to A.5. above. The noted attachments, specific for meters, provide information of the modeling inputs and results. Section A.6. describes how the meter forecasts are divided into the proper rate code designation. *Attachment A-48 Sales and Meter Count Forecasts to Revenue Forecast.xlsx* contains the forecast of meter counts, by state and rate code, including manually forecasted customer meter counts.

The resulting forecasted meter counts are imported into the revenue model.

g) Manually Forecasted Customer Inputs

As described in the sales forecast, OTP has some manually forecasted customers. The sales for these customers are imported into the revenue model separately from the rest of the sales. The revenue forecast for these customers is calculated manually, as well. To calculate the revenue for the manually forecasted customers we use the following inputs for each customer:

- Forecasted sales
- Estimated load factor or baseline demand
- Station allocation (if they have multiple stations - used for a Pipeline Customer)
- Time of Day allocation (if they are on a TOD Rate)
- Pricing for each necessary rate code’s billing determinant

These inputs, excluding pricing, are based on historical data, and are modified based on information obtained from customers themselves.

SAS Program: LF and Allocations

The SAS program (Attachment B-07A LF and Allocations_Not_Public.pdf) imports three years of individual customer historical data and assigns each manually forecasted customer a weighted average load factor, Time-of-Day allocations, where applicable, and the percent of usage distribution per Enbridge station in Minnesota. The load factor is calculated by dividing the usage by the product of demand and total number of hours in a given period. The Time-of-Day allocations determine the percentage of usage in the three TOD periods of On-Peak, Mid-Peak and Off-Peak. The percent of usage distribution displays the proportion of usage between the Minnesota Enbridge stations. The results are exported to an Excel file (Attachment B-07B LF and Allocations_Not_Public.xlsx).

4. REVENUE MODEL

Once all the inputs have been determined, they are imported into the revenue model. The manually forecasted customers' revenue is computed by customer/year/month, and the non-manually forecasted customers' revenue is computed by state/year/month/rate code. They are added together, along with the Credit/Miscellaneous revenue, at a state/year/month/rate code level. The rate code revenues are then summed to the 10 classes corresponding to the cost of service study. The calculations are discussed in more detail below.

a) Manually Forecasted Customers

The manually forecasted customers' forecasted sales, load factor/baseline demand, station allocations, time-of-day allocations, system marginal energy pricing (SMEP) allocations, and price for each billing determinant are imported into the revenue model. If the account has a load factor charge, their monthly sales is divided by the load factor divided by 730 resulting in the kW for each customer.[12] If the customer has a baseline demand, it is used as the kW. **[PROTECTED DATA BEGINS...**

... PROTECTED DATA ENDS]

If the customer is on a Time of Day rate, the Time of Day allocator is multiplied by the customer's total sales to get the sales for each rate code. If the customer has elected SMEP, the rate code sales are multiplied by the appropriate baseline and incremental

[12] 730 is the number of hours in the average year divided by 12 to get the average number of hours in a month.

percentages to determine the baseline and incremental sales. The demand also has a Time of Day allocator which is handled in the same manner as the kWh; however, if the customer has a baseline, the demand allocators are set to 100 percent since the baseline is the same for all hours of the day. If a facilities (ratcheted) kW is needed for the account, the annual maximum kW for the test year is found and applied to each month for that year as the ratcheted kW.[13] Thus for each account, we now have the kWh, kW, and ratcheted kW for each of the customer's rate codes. Each rate code is multiplied by the corresponding price and summed by determinant and then by customer.

b) Non-Manually Forecasted Revenue

Once the sales, demand ratios, ratcheted demand ratios, pricing and meter forecasts are imported into the revenue model, a series of calculations take place to find the revenue for each rate code. The state/month/rate code level kWh is first multiplied by both the corresponding demand ratios and the ratcheted demand ratios. This will give the needed billing kW and ratcheted kW for each rate code. Thus, we now have all the forecasted billing determinants for each rate code. The pricing files (*Attachment B-01 Rates.xlsx and Attachment B-04 Composite Pricing_Lighting.xlsx*) contains monthly prices for the following: kWh tier 1, kWh tier 2, kW, facilities kW tier 1, facilities kW tier 2, fixed facilities charge, and customer charge. Then the following calculations are made by state/year/month/rate code:

Tier 1 kWh revenue	= kWh tier 1 charge*Forecasted kWh
Tier 2 kWh revenue	= kWh tier 2 charge*Forecasted kWh
kW revenue	= kW charge*Forecasted kW
Tier 1 ratcheted kW revenue	= Facilities kW tier 1 charge*Forecasted ratcheted kW
Tier 2 ratcheted kW revenue	= Facilities kW tier 2 charge*Forecasted ratcheted kW
Fixed facilities revenue	= Fixed facilities charge*Forecasted meter count
Customer revenue	= Customer charge[14]*Forecasted meter count

Once each of these pieces has been calculated, the Credits/Miscellaneous revenue is added into their respective state/year/month/rate code resulting in the non-manually forecasted customer revenue.

As the last step of the Revenue Forecast, the non-manually forecasted customer revenue and manually forecasted customer revenue are summed by rate code, and then to the cost of service class revenue by state.

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[13] This is not a "true" ratchet as the value may be pulled from a future month.
[14] At this point the customer charge includes both the customer charge and the annual seasonal charge.

C. METER TO CUSTOMER TRANSLATION

The test year sales forecast in OTP's last rate case was based on Use Per Customer (UPC) models. This required OTP to develop forecasts for the number of customers and then develop a process to translate customers to meters because pricing is done at the meter, not customer level. OTP has since changed its sales forecasting process to utilize UPM in the sales forecast, thereby avoiding the need to translate customers to meters when moving from the sales forecast to the revenue model. OTP does still use customers in the development of allocation factors.

Volume 2B

Direct Testimony and Supporting Schedules:

David G. Prazak

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

RATE DESIGN AND TARIFF CHANGES

Direct Testimony and Schedules of

DAVID G. PRAZAK

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My Name is David G. Prazak. I am employed by Otter Tail Power Company (OTP or the Company).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Manager of Pricing and Rate Design. I am responsible for managing the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates and rate design and load research.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(DGP-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony: (1) describes the rate structure objectives that were used in developing OTP's proposed rates; (2) explains the role of embedded and marginal costs in OTP's rate design; (3) describes the proposed rate design for OTP's rate schedules; (4) introduces new rate structure designs, and (5) supports the proposed language changes of OTP's rate schedule provisions.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. OTP's rate design provides a reasonable opportunity to achieve OTP's revenue requirement. The rate design is based on marginal costs, and, as such, promotes efficient use of resources.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss OTP's rate design process, including the objectives that guide our rate design and the role of marginal costs in rate design. In Section IV, I discuss the rate restructuring initiative and rate changes since our last rate case, Section V identifies our rate design proposals for each customer class. Section VI identifies other rate offerings and Section VII identifies tariff changes other than rates.

Q. ARE YOU SPONSORING ANY OF THE ADDITIONAL SUPPORTING FINANCIAL DATA IN VOLUME 3 OF OTP'S APPLICATION?

A. Yes. I am sponsoring Schedules E-1 and E-2 included in Volume 3, both of which show operating revenues under present and proposed rates.[1]

Q. DID OTP IDENTIFY AN ISSUE WITH THE PROPOSED REVENUE DATA IN SCHEDULES E-1 AND E-2 AS IT FINALIZED THIS CASE FOR SUBMISSION?

A. Yes. OTP determined that credits associated with certain voluntary riders were treated incorrectly in the development of proposed operating revenues, resulting in proposed energy charges being slightly overstated. For context, the credits are equal to only approximately 0.50 percent of total proposed energy-charge revenue for the 2024 Test Year. OTP will correct this issue in the development of final rates.

III. RATE DESIGN PROCESS

A. Overall Rate Structure Objectives

Q. WHAT ARE THE RATE STRUCTURE OBJECTIVES THAT GUIDE OTP'S PROPOSAL IN THIS CASE?

A. OTP identified the following rate structure objectives:

- The rate design should give OTP a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- The rate design should promote efficient use of resources. This implies giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time of day (TOD) differences.

[1] Please note, Volume 3, Schedule E-2 excludes the billing determinants for the Super Large General Service (SLGS) rate and only shows total revenue, rather than its component parts (i.e., energy, demand, fixed) in order to protect an individual customer's data. As discussed in Schedule 2 to the Direct Testimony of OTP witness Ms. Tammy K. Mortenson, some present revenues are calculated using weighted composite prices. There can be slight differences between present revenues calculated using the composite pricing approach versus pricing rate code-level billing determinants. We have identified the effect of those differences in Volume 3, Schedule E-2, as the "Revenue Adjustment" line item. The cumulative difference of these adjustments is ($106,449), or less than 0.052% of total present base revenues.

- Rate design changes should be gradual where necessary to avoid abrupt bill impacts.
- The rate design should be based on structures that are reasonable and nondiscriminatory. This includes minimizing cross-subsidies within rate classes to the extent reasonably possible.
- The rate design should result in rates that are administratively feasible. This includes taking metering and billing system constraints into account and avoiding unnecessary complexity that might confuse customers.
- The rate design should preserve the attractiveness of load control/interruptible riders, as those riders provide substantial benefits to all OTP customers.

B. Role of Embedded and Marginal Costs in Rate Design

Q. PLEASE SUMMARIZE THE MAIN POINTS OF THIS PORTION OF YOUR DIRECT TESTIMONY.

A. This portion of my Direct Testimony makes two main points:

- Consistent with OTP's rate design objectives, I based our rate structures on OTP's marginal costs, tempered by the need to control bill impacts and maintain a suitable inter- and intra-class relationship between the regular rates and riders available to OTP's customers.
- The proposed intra-class revenue requirement allocation was determined by applying the Equal Percentage Marginal Cost (EPMC) methodology, where applicable. The EPMC method follows our rate structure objectives by improving the efficiency of price signals and reducing cross-subsidies.

Q. WHAT IS THE STARTING POINT FOR THE RATE DESIGN?

A. The rate design begins with the customer class base revenue responsibilities shown in Schedule 7 to the Direct Testimony of OTP witness Ms. Amber M. Stalboerger. I then take those class base revenue responsibilities and allocate them to rate classes. Finally, I develop the individual rate components (energy charges, demand charges, and fixed charges) for each rate class, based on marginal costs, which are designed to recover the overall revenue requirement.

Q. WHAT IS THE DIFFERENCE BETWEEN A CUSTOMER CLASS AND A RATE CLASS?

A. A customer class is a group of customers with similar usage patterns and electrical facilities. Customers within the customer class may have more than one rate option – or rate class. For example, the Residential customer class has two rates: a general service rate and a demand-controlled rate, each with their own applicability requirements.

Q. ARE THE CLASS REVENUE RESPONSIBILITIES DEVELOPED BY MS. STALBOERGER BASED ON EMBEDDED COSTS?

A. Yes. OTP's revenue requirement and class revenue responsibilities are calculated to recover the cost of service, which is measured by embedded costs.

Q. HOW ARE MARGINAL COSTS USED IN THE RATE DESIGN PROCESS?

A. Marginal costs are used in the process of allocating class revenue responsibilities to rate classes and in the development of individual rate components. I describe the allocation of class revenue responsibilities to rate classes in this section of my Direct Testimony and focus on the development of individual rate components in Section V, below.

Q. ARE THERE BENEFITS OF USING BOTH EMBEDDED AND MARGINAL COSTS IN RATE DESIGN?

A. Yes. Rates must give the utility the opportunity to recover its embedded costs. By using marginal costs to design those rates, OTP's rate design maintains the benefits of marginal cost price signals while still producing overall revenues that recover the cost of service. The benefits of marginal cost price signals include designing rates with seasonal, and where possible, time of day differences, and promoting the efficient use of electricity through appropriate price signals.

1. Marginal Cost Study

Q. WHAT IS THE DIFFERENCE BETWEEN MARGINAL COSTS AND EMBEDDED COSTS?

A. The most important difference between these two types of costs are historical costs (embedded) versus future costs (marginal). Marginal cost, as defined in OTP's marginal cost studies, is the change in total cost of service with respect to a small change in demand of a product or service. These marginal costs take into consideration changes in forecasted investments at various service levels and their impacts on utility system operations.

Q. HOW ARE MARGINAL COSTS DEVELOPED?

A. OTP engaged Ms. Amparo Nieto of Charles River Associates (CRA) to develop a marginal cost study covering the period 2024-2028 applicable to service in our three retail jurisdictions (the 2024 Marginal Cost Study). The 2024 Marginal Cost Study was developed with input from OTP staff regarding OTP's planning and operating practices, regional market price data, and system characteristics. OTP staff has also closely reviewed the 2024 Marginal Cost Study to make sure it does in fact reflect OTP's marginal costs. A copy of the 2024 Marginal Cost Study is included as Exhibit___(DGP-1), Schedule 2.

Q. HOW ARE THE RESULTS OF THE 2024 MARGINAL COST STUDY APPLIED TO THE RATE DESIGN PROPOSAL?

A. The 2024 Marginal Cost Study provides an accurate calculation of current marginal costs and was used to guide our rate design proposals. Notably, those marginal costs are very different from those calculated in the marginal cost study filed in our last rate case (the 2018 Marginal Cost Study), reflecting changes in the industry's marketplace.

Q. WHAT ARE THE MAIN DIFFERENCES IN THE RESULTS OF THE 2024 MARGINAL COST STUDY AND THE RESULTS OF THE 2018 MARGINAL COST STUDY?

A. All marginal energy costs have increased, and seasonal marginal capacity costs have decreased. For example:

- Annual, summer and winter marginal <u>energy</u> costs are higher in the 2024 Marginal Cost Study than they were in the 2018 Marginal Cost Study. Annual marginal energy costs have increased by 82 percent, winter marginal energy costs have increased by 88 percent and summer marginal energy costs have increased 70 percent.
- Annual marginal <u>capacity</u> costs have decreased 33 percent, with summer marginal capacity costs decreasing by 65 percent and winter marginal capacity costs slightly increasing by 6 percent.

Q. WHAT IS DRIVING THESE CHANGES?

A. There are two general drivers. First, marginal costs should reflect the wholesale marketplace. The wholesale market is influenced by any number of factors, including federal and state energy policies, various generation mixes, improvements in transmission capability, other infrastructure investment, and energy consumers themselves. These factors are combining in the Midcontinent Independent System Operator (MISO) market in a way that results in a general trend of higher energy prices and lower capacity costs for the near-term, primarily from higher natural gas prices.

The second driver is the allocation of marginal capacity costs both seasonally and in the time of day periods. Both summer and winter energy costs in the time of day periods increased similarly, with winter off-peak more than doubling. Summer generation capacity costs were reduced by about two-thirds, whereas winter capacity costs increases were fairly steady. Another marginal capacity cost, distribution substation and truckline feeder costs, has increased by 57 percent. This is not overly surprising, as supply chains for the utility sector were impacted during the COVID-19 pandemic and continue to be challenged. Additionally, the distribution substation probability of peak has moved from summer (2018 Marginal Cost Study) to winter (current study). The allocation of these winter costs is now more concentrated during the on-peak period.

2. Proposed Intra-Class Revenue Allocation

Q. PLEASE DESCRIBE THE PROCESS OF DEVELOPING INTRA-CLASS REVENUE ALLOCATIONS.

A. When the customer class has two or more rate classes, the class revenue responsibilities developed by Ms. Stalboerger must be further disaggregated to the rate class level before designing rates. We use a variety of methods to develop these intra-class revenue allocations, including the EPMC methodology.

Q. WHAT IS THE EPMC METHODOLOGY?

A. The EPMC method allocates the class revenue responsibilities to rate classes based on each rate class's marginal cost revenues. We determine marginal cost revenues for a rate class by multiplying the marginal cost times the rate class billing determinants. Exhibit___(DGP-1), Schedule 3 describes total marginal cost revenues by customer and rate class.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE EPMC METHODOLOGY?

A. Yes. Table 1 below provides a simplified example of the "pure" version of the EPMC method, meaning it allocates class revenues to rate classes based entirely on the marginal cost revenues calculated using the results of the marginal cost study. The example is based on a customer class with two rate classes, where one rate class provides 80 percent of the overall marginal cost revenues for that customer class and the other rate class provides 20 percent of the overall marginal cost revenues for that customer class.

Table 1
Simplified EPMC Methodology Example

	Marginal Cost Revenue Percentage		Revenue Responsibility	
Rate Class A	80%	(a)		
Rate Class B	20%	(b)		
Class Revenue Responsibility			$100,000	(c)
Rate Class A			$80,000	[(a)*(c)]
Rate Class B			$20,000	[(b)*(c)]

Q. WHAT ARE THE BENEFITS OF THE EPMC METHODOLOGY?

A. The EPMC method is aligned with our rate structure objective to have efficient rates that reflect marginal costs. Using marginal cost-based revenues to allocate revenue from customer classes to rate classes sets efficient revenue targets for rates within a class.

Q. IS OTP RECOMMENDING USING THE PURE, OR UN-MODIFIED VERSION OF THE EPMC METHODOLOGY TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS IN THIS CASE?

A. Yes. As shown in Table 2, below, I recommend developing Controlled Service – Interruptible intra-class revenue allocations based on an un-modified application of the EPMC method.

Q. IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS FOR OTHER CUSTOMER CLASSES?

A. Yes. I recommend using a modified version of the EPMC methodology to develop intra-class revenue allocation for the General Service and Irrigation classes.

Q. WHY IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY FOR THESE CLASSES?

A. The pure EPMC method can sometimes result in dramatic changes in rate class revenue responsibilities, which, in some cases, is necessary to minimize cross subsidization. However, using the modified version of the EPMC method allows us to balance the efficiency benefits of marginal cost-based rates with other important rate structure goals, like avoiding abrupt changes in intra-class revenue responsibilities. The modified EPMC method allows us to move a class more gradually towards cost, and away from cross-subsidization, without making too large a change to any one class or sub-class at any one time.

Q. PLEASE DESCRIBE THE MODIFIED VERSION OF THE EMPC METHODOLOGY YOU USED TO DEVELOP GENERAL SERVICE AND IRRIGATION INTRA-CLASS REVENUE RESPONSIBILITIES.

A. We developed General Service and Irrigation intra-class revenue responsibilities using a modified version of the EPMC method (referred to herein as EPMC Method 1). This method changes the results from strict application of EPMC within a class. Under this method, the target revenue for a rate class is 50 percent of the difference between: (1) the overall percentage revenue increase proposed by Ms. Stalboerger for the customer class; and (2) the percentage revenue increase that would result from applying EPMC to each rate class within the customer class. This approach also recognizes the goal of gradualism and takes into consideration the fact that the customer class as a whole is receiving a revenue increase.

Q. HOW WERE INTRA-CLASS REVENUE RESPONSIBILITIES DEVELOPED FOR OTHER CLASSES?

A. Intra-class revenue responsibilities for the other customer classes are based on the class-level base rate revenue increases proposed by Ms. Stalboerger. For example, Section 14.07 - Controlled Service Off Peak has a single rate schedule with three rate classes – secondary service under and over 100 kW and primary service. Ms.

Stalboerger's recommended base rate revenue increase for the Controlled Service Off Peak class is 26.52 percent. The resulting increases for two of the three rate classes that had customers were a result of the outcome of the rate designs based on marginal cost. In another example, rate classes were assigned increases equal to the base rate revenue increases prosed by Ms. Stalboerger, while others had different rate class increases. In all cases, whether we applied modified or regular EMPC, total customer class increases yielded the embedded cost revenue assignment.

Q. PLEASE IDENTIFY THE DIFFERENT APPROACHES USED TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS.

A. The table below identifies the different approaches for developing intra-class revenue allocations. Further details are provided in Schedule 3.

Table 2
Summary of Approaches to Developing Intra-Class Revenue Responsibilities for All 10 Customer Classes with Multiple Rate Classes

Customer Class	Method
Residential	Class Level Increase
Farm	Class Level Increase
General Service	EPMC Method 1
Large General Service	Class Level Increase
Irrigation	EPMC Method 1
Outdoor Lighting	Class Level Increase
Other Public Authority	Class Level Increase
Controlled Service - Interruptible	EPMC
Controlled Service - Deferred	Class Level Increase
Controlled Service – Off Peak	Class Level Increase

IV. RATE RESTRUCTURING

A. Rate Restructuring Initiative

Q. PLEASE DESCRIBE OTP'S RATE RESTRUCTURING INITIATIVE.

A. The rate restructuring initiative involved examination of rate offerings in the context of changes in the energy industry, customers, and business administration.

OTP assembled input from various departments in the Company to discuss the basics of what is, and what is not, needed – now and in the future.

Q. WHAT WAS OTP HOPING TO ACHIEVE THROUGH THE INITIATIVE?

A. OTP met to determine the goals of the initiative. Three goals emerged from our discussions:

- Achieve less complexity yet maintain flexibility;
- Recognize the balance of needs between costs/revenue requirements and customers; and
- Meet changing customer expectations.

Q. PLEASE DESCRIBE THE RESTRUCTURING FRAMEWORK DEVELOPED FROM THE GOALS.

A. The goals led us to develop five categories (5 Cs) to examine and consider during the restructuring efforts for our rate offerings.

1. *Class Structures*: examine and consider the number of customer classes utilized in our class cost of service study.
2. *Continuity/Uniformity*: examine and consider offering the same type of rate offerings in all our jurisdictions.
3. *Customer-Centric/Flexibility*: examine and consider rate offerings that address customer wants/needs, consistent with jurisdictional statutes.
4. *Consistency/Compatibility*: examine general rules and regulations as well as rate schedules to develop consistent language across jurisdictions to the extent possible under jurisdictional statutes and other requirements.
5. *Close Loopholes*: examine and consider rate offerings that reduce ambiguity and increase the intent of rate design and/or other compliance obligations.

Q. WHAT OTHER STEPS OCCURRED DURING OTP'S RATE RESTRUCTURING EFFORTS?

A. The rate restructuring team utilized the 5 Cs and assembled a list of measures to consider. The measures went through another screening step to aid in the selection of measures. The screening steps included identifying the appropriate regulatory proceeding for different measures, research, resources and other timing constraints, and items that would rely on outcomes of pending dockets. Sub-teams were assigned to examine and consider the best restructuring efforts to be included in this rate case consistent with the goals and 5 Cs framework.

Q. PLEASE DESCRIBE THE OUTCOMES OF THE RATE RESTRUCTURING EFFORTS INCLUDED IN OTP'S RATE CASE PROPOSAL.

A. The measures identified for inclusion in this rate case are as follows:

- Restructure the Residential Demand Control Rate;
- Combine two separate but related rate schedules into one (for example Small and Large Dual Fuel);
- Expand air conditioning control to additional months and increase compensation;
- Ensure consistent language among rates with billing demand/facilities charges;
- Propose customer rate schedule placement qualifications for General and Large General Service Customer rates;
- Create alignment of rate classes within the appropriate customer class;
- Review & revise allocation methodology for controlled service rates;
- Develop a special facility charge calculation to be used in Sections 5.02, 11.02 - Irrigation, and 14.12 - Bulk Interruptible;
- Examine and modify General Rules and Regulations for changing industry conditions; and
- Add a 3-month trial period to a time-differentiated rate.

Q. WHERE IN YOUR TESTIMONY DO YOU ADDRESS THE SPECIFICS OF THESE RESTRUCTURING MEASURES?

A. Changes to existing base rates due to the rate restructuring initiative are discussed in various parts of Sections V-VI. Changes to tariffs due to the rate restructuring initiative are discussed in Section VII.

B. New Rates Since Last Rate Case

Q. HAS OTP INITIATED ANY NEW BASE RATE OFFERINGS SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. We added LED Street and Area Lighting Services in Case Nos. PU-21-76 and PU-22-190. Also, our Real Time Pricing and Large General Service Rider offering currently is pending in Case No. PU-23-290.

V. INDIVIDUAL RATE PROPOSALS

A. Residential Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE RESIDENTIAL CLASS?

A. There are two rate schedules in the Residential Class: Residential Service (Section 9.01) and Residential – Controlled Demand (Section 9.02).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.01 RESIDENTIAL SERVICE RATE.

A. We are proposing a single rate structure change for this rate: adding a fixed facility charge. This rate also includes a monthly customer charge, a minimum bill equal to the customer charge plus facilities charge, and a flat seasonally differentiated energy charge. The table below identifies proposed energy charges, which are purposely above marginal cost, but still provide a reasonably efficient price signal for residential customers. The proposed customer charge is about 100 percent of marginal cost. OTP developed marginal costs for facilities based on customer usage, a proxy for design demand, tied to transformer and other customer-related distribution equipment. The proposed fixed facility charge is $3.50/month, significantly less than marginal facilities charges under the 2024 Marginal Cost Study. By not collecting the balance of the facilities cost, about $12.00/month, OTP will collect these costs in the energy charge instead of fixed charges.

Table 3
Comparison of Current and Proposed 9.01 Residential Rate and Marginal Costs

Residential Service	Section 9.01					Energy Charge	
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		All Year	per kWh Summer	Winter
Current Rate	$14.00	Customer + Facilities			ENERGY	$0.08050	$0.05446
	$56.00		$0.00				
Seasonal Customer Charge				AC Credit(4 months)	-$8.25		
				Water Heating Credit	-$8.00		
Proposed Rate	$17.00	Customer + Facilities	$3.50		ENERGY	$0.07702	$0.08743
Seasonal Customer Charge	$68.00						
				AC Credit(5 months)	-$8.00		
				Water Heating Credit	-$8.00		
Marginal Costs	$17.07				All kWh	$0.05677	$0.06444
		URBAN	$15.55				
		RURAL	$87.06				

Q. ARE YOU RECOMMENDING AN INCREASE TO THE 9.01 RESIDENTIAL SERVICE RATE CUSTOMER CHARGE?

A. Yes. We are proposing a modest $3.00 per month increase in the 9.01 Residential Service customer charge.

Q. WHY DO YOU RECOMMEND AN INCREASE IN THE 9.01 RESIDENTIAL SERVICE RATE CUSTOMER CHARGE?

A. Our recommendation is informed by our rate structure objectives, specifically that rates reflect marginal costs, promote the efficient use of resources and minimize cross-subsidies within rate classes to the extent reasonably possible.

Q. HOW DOES THE PROPOSED CUSTOMER CHARGE FURTHER THESE OBJECTIVES?

A. First, the proposed customer charge moves rates essentially to marginal cost. The 2024 Marginal Cost Study indicates that marginal customer-related costs are $17.07/month. Second, when the customer charge is set below marginal cost, the balance of the costs the customer charge is designed to recover are instead recovered through volumetric charges. This means that customers with usage that exceeds the class average pay more than their fair share of the fixed cost of service. By setting the customer charge essentially at marginal cost, means that none of our customers in this class will be paying more than their fair share via volumetric charges.

Q. ARE THERE UNIQUE ELEMENTS OF OTP'S CUSTOMER POPULATION THAT MAKE INTRA-CLASS EQUITY ESPECIALLY IMPORTANT?

A. Yes. OTP's service territory is predominately rural in nature, and natural gas service is not available in many of our communities. Customers with electric heating are more likely to have usage that exceeds the class average, meaning they end up paying more than their fair share of the cost of service when customer charges are too low.

Q. WHAT ARE THE BASE RATE IMPACTS OF YOUR PROPOSED 9.01 RESIDENTIAL RATE?

A. To analyze base rate impacts from each of OTP's proposed rates, we computed an average customer's billing determinants for each customer duo-decile (20 equal segments) and calculated the base rate portion of that customer's bill under current base rates and under proposed rates for each rate schedule within each class, using 2024 Test Year forecasted billing information. We then created bar charts showing the average monthly bill changes for the duo-deciles (20 equal segments) of customers, ordered by average monthly kWh use. Each bar represents 5 percent of customer accounts in the class. It is important to keep in mind that the smallest one or two bars probably include significant numbers of customers who were not on the system for the entire year, are seasonal customers, or are anomalies such as customers who shifted from one rate to another (or shifted load to a rider) during the year.

As shown in Figure 1, below, more than 75 percent of Residential customers will see the non-fuel base rate portion of their bill change by less than $30 per month.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE BILL IMPACTS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. Figure 1 below and all subsequent duo-decile bill impacts figures *do not* account for costs moving out of base rates and associated changes to riders. They only show the base rate impact of the Company's proposals in this case. The actual *bill* impact will be lower than what is shown in the duo-decile figures due to the reduction of rider rates that is occurring as part of the movement of rider costs into base rates.[2]

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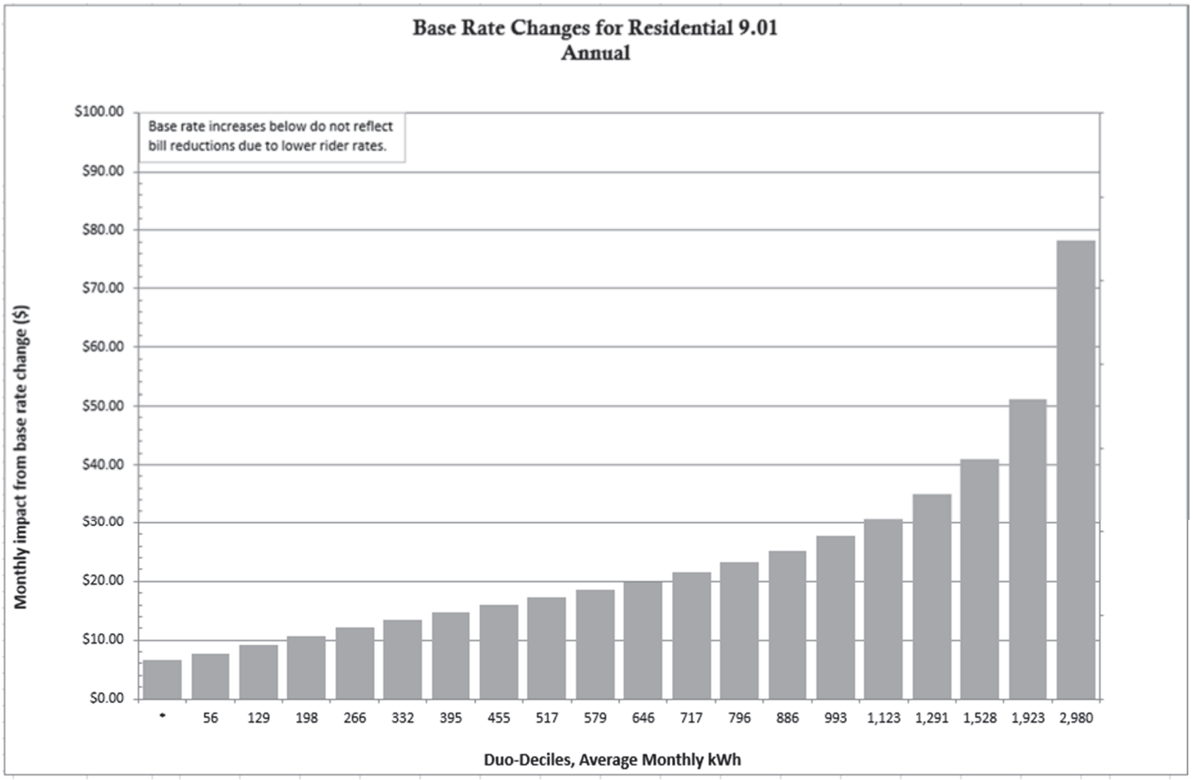
[2] Volume 3, Schedule E-2 identifies the class-level net impact of the Company's proposals (i.e. increase of base rates and reduction of rider rates).

Figure 1



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.02 RESIDENTIAL-CONTROLLED DEMAND RATE.

A. OTP's proposed Residential Controlled Demand (RCD) rate is part of our restructuring efforts. The proposal changes how customers are charged in both the summer and winter seasons. First, summer demand charges are eliminated, and the summer energy charges are the same as the 9.01 Residential Service. Second, the proposed demand charges will continue to be levied with a 12-month ratchet, using only the winter season. The winter demand rates continue to be an important price signal as the rate is designed for reducing demand in the winter when OTP's system peaks.

As shown in the table below, the proposal continues with customer charges set near marginal costs. Similar to the Residential Service 9.01 rate, we are introducing a fixed facilities charge to collect a portion of the larger facilities costs needed for winter electric heating customers. Winter-only demand costs are set at marginal capacity costs. Lastly, the energy costs are set to obtain the remainder of the revenue requirement. The proposed energy charges, which are above marginal cost, still provide a reasonably efficient price signal. The present (i.e., current) and proposed rate components are identified in the table below.

Table 4
Comparison of Current and Proposed 9.02 Residential Controlled Demand and Marginal Costs

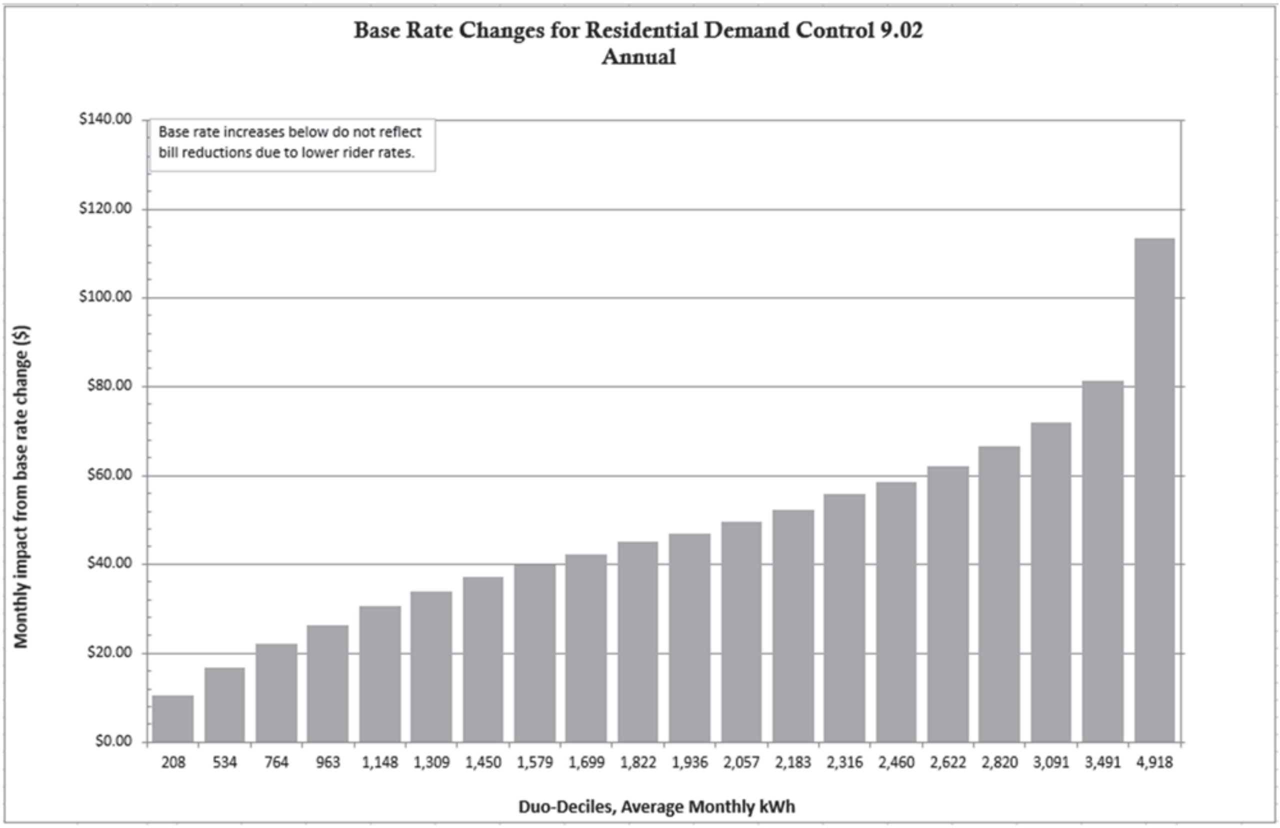
RESIDENTIAL DEMAND CONTROL SERVICE	Section 9.02									
		Customer Charge per month	Minimum Bill per month		Facilities Charge per month		Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer	Demand Charge per kW per mo. Winter
Current Rate									per 12-mo. max monthly	
	Customer Charge per Month:	$20.10	Cust. + Facility + Demand Charges	Facilities Charge per Month All Customers:	$0.00	All kWh:	$0.03379	$0.03461	$8.00	$8.00
									per 12-mo. max monthly	
Proposed Rate							Summer	Winter	Summer	Winter
	Customer Charge per Month:	$21.00	Cust. + Facility + Demand Charges	Facilities Charge per Month	$7.00	All kWh:	$0.07702	$0.05106	$0.00	$11.00
							Energy Only:		Capacity Only	
							Summer	Winter	Summer	Winter
Marginal Costs		$21.37			$26.64		$0.05677	$0.05025	$0.00	$11.02

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 9.02 RESIDENTIAL CONTROLLED DEMAND RATE?

A. The base rate impacts, shown in the figure below, result in more than 75 percent of RDC customers seeing the base rate portion of their bill change by less than $60 per month. For comparison purposes, the RDC 2024 Test-Year average customer usage is 2.5 greater than average Residential usage,[3] essentially unchanged since our last rate case.

[3] 9.02 monthly average usage: 1,969 kWh; 9.01 monthly average usage: 791 kWh.

Figure 2



B. Farm Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE FARM CLASS?

A. There is one rate schedule in the Farm Class: Farm Service (Section 9.03).

Q. ARE YOU PROPOSING ANY RATE STRUCTURE CHANGES FOR THE FARM CLASS?

A. No. Our proposal includes increasing the customer charge to be slightly over marginal customer costs and increasing both facilities charges for single and three-phase customers. These charges are designed to collect a portion (less than 18 and 29 percent, respectively) of the fixed marginal costs to serve. The present and proposed rate components are identified in the table below.

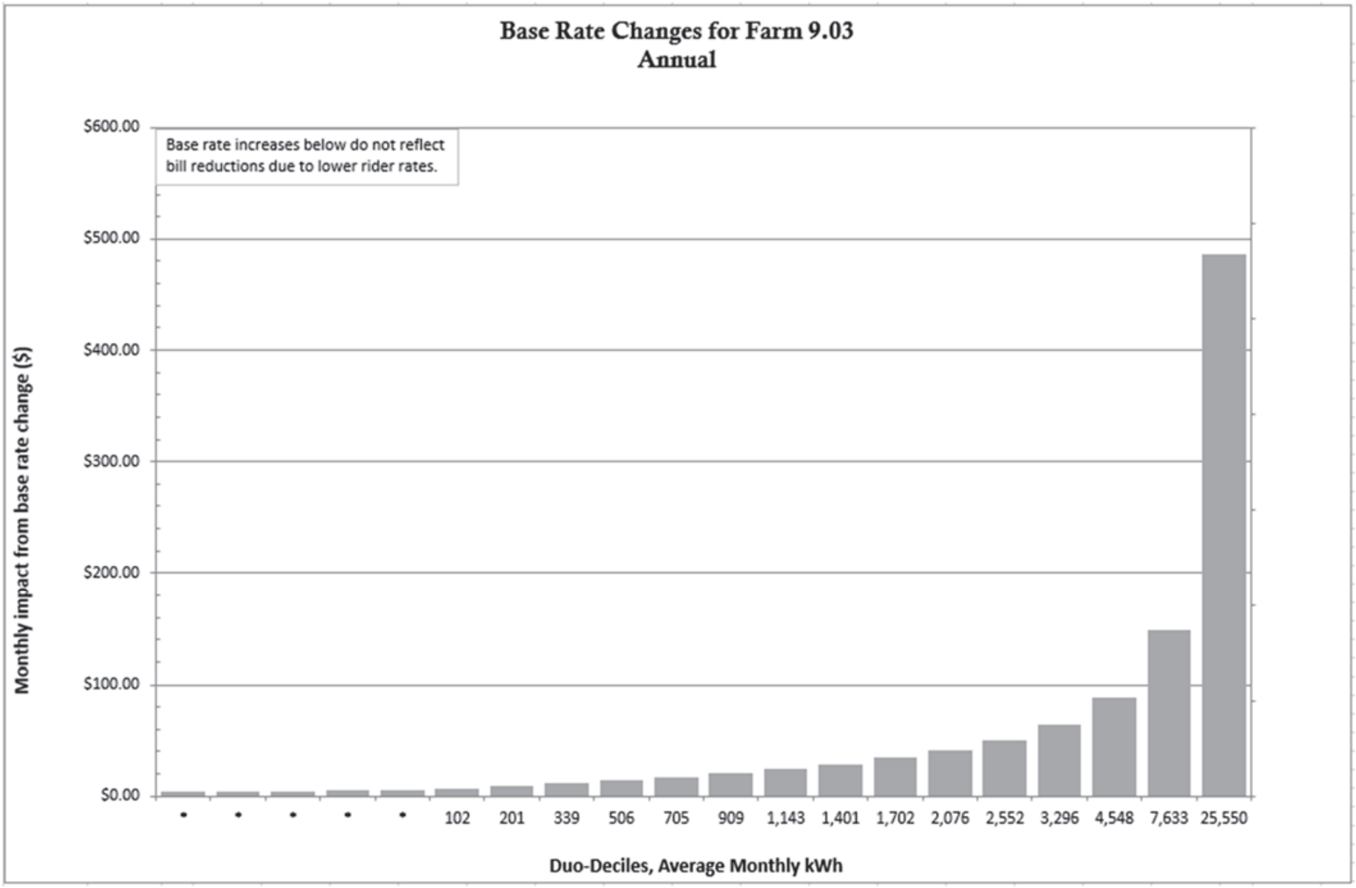
Table 5
Comparison of Current and Proposed 9.03 Farm Service and Marginal Costs

FARM SERVICE	Section 9.03						
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per kVA of Transformer		Energy per kWh	Summer	Winter
Current Rates	$17.40	Cust + Fac	Facilities Charge per kVA of Transformer Single-Phase , per Month 3-Phase, per Month	 $10.00 $20.00	All kWh	$0.06793	$0.04595
Proposed	$22.00	Cust + Fac	Facilities Charge per kVA of Transformer Single-Phase , per Month 3-Phase, per Month	 $20.00 $40.00	All kWh	$0.06361	$0.07221
Marginal Costs	$21.71	Cust + Fac	Single-Phase Monthly Charge 3-Phase Underground > 25kVa	$ 112.19 $ 139.56	All kWh	$0.05677	$0.06444

Q. WHAT ARE THE BASE BILL IMPACTS FROM YOUR PROPOSED FARM RATE?

A. As shown below, approximately 90 percent of customers (the first 18 duo-deciles) see monthly base bill increases of less than $95 per month.

Figure 3



C. General Service Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE GENERAL SERVICE CLASS?

A. There are three rates within the General Service Class: Small General Service (Under 20 kW) (Section 10.01); General Service (20 kW or Greater) (Section 10.02); and General Service – Time of Use (Section 10.03).

Q. ARE YOU PROPOSING TO RESTRUCTURE RATES IN THE GENERAL SERVICE CLASS?

A. Yes, I propose structural changes to Sections 10.02 and 10.03, which I will discuss in more detail below. In summary, for both of these rates, I am proposing to close potential loopholes in these two rate schedules by limiting the ability of certain larger customers with lower load factors to move from the Large General Service rates to General Service rates, which by design has lower demand and higher energy costs.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.01 SMALL GENERAL SERVICE (UNDER 20 KW) RATE.

A. Changes to this rate include increasing all rate elements and adding a new fixed facilities charge per month to recover fixed charges. The customer charge is set at marginal cost, and the balance of the revenue requirement is collected in the energy charge. The present and proposed rate components are identified in the table below.

Table 6
Comparison of Current and Proposed 10.01 Small General Service (Under 20kW)
Rate and Marginal Costs

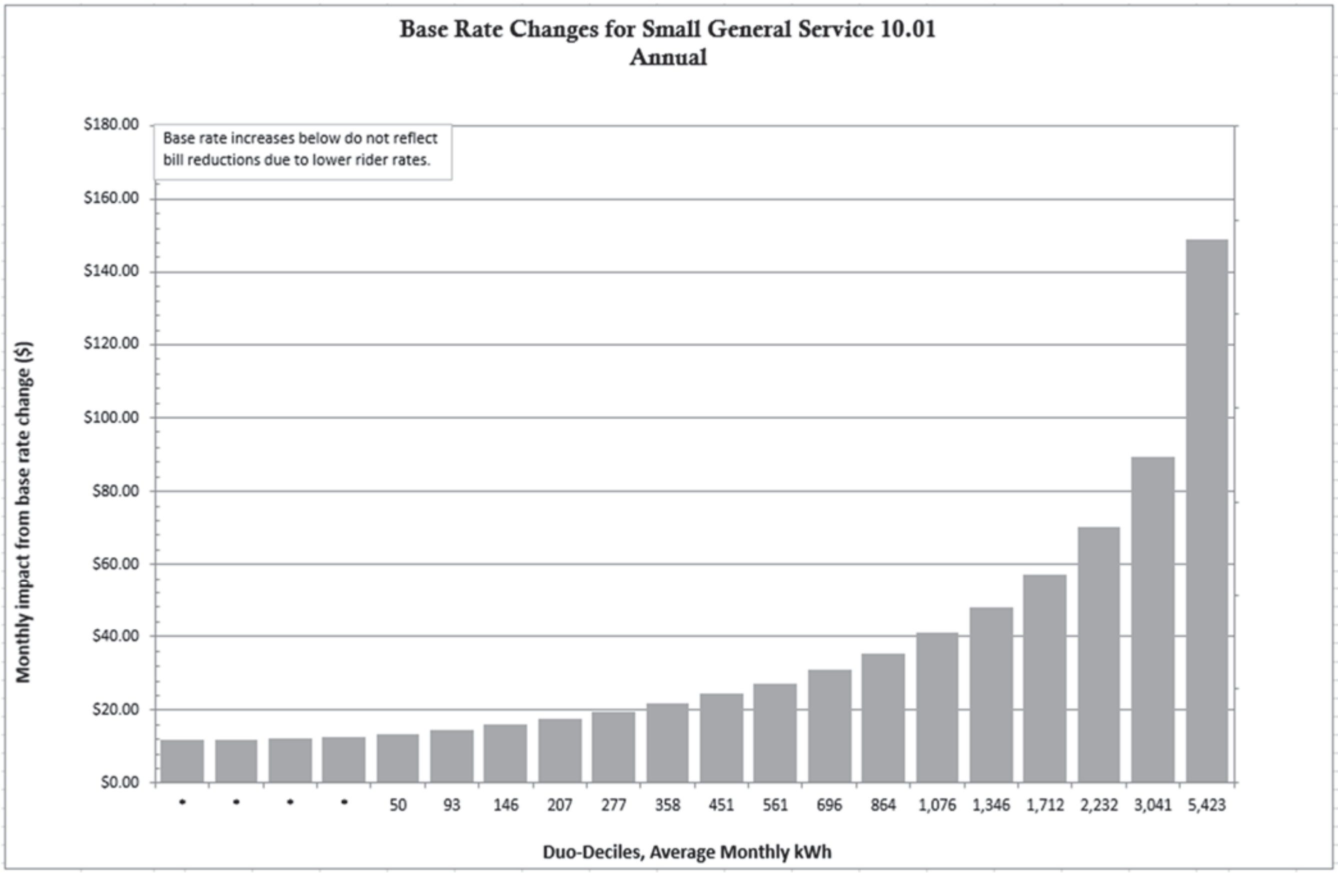
SMALL GENERAL SERVICE — Section 10.01
Under 20 KW

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current Rate GS					
Secondary Service	$24.90	Customer Charge & Facilities Charge	NA	$0.06682	$0.04521
Primary Service	$24.90	Customer Charge & Facilities Charge	NA	$0.06440	$0.04331
Proposed GS Rate					
Secondary Service	$24.90	Customer Charge & Facilities Charge	**$12.00**	$0.07117	$0.08079
Primary Service	$24.90	Customer Charge & Facilities Charge	**$12.00**	$0.06918	$0.07912
Marginal Costs					
Secondary Service	$24.19		$26.64	$0.05677	$0.06444
Primary Service	$24.19		$26.64	$0.05518	$0.06311

Q. WHAT ARE THE BASE BILL IMPACTS FROM YOUR PROPOSED 10.01 SMALL GENERAL SERVICE (UNDER 20 KW) RATE?

A. About 90 percent of the class (represented by the first 18 duo-deciles) will see an increase of about $70.00 per month or less.

Figure 4



Q. PLEASE DESCRIBE YOUR STRUCTURAL RATE DESIGN PROPOSAL FOR SECTIONS 10.02 AND 10.03.

A. Currently, Sections 10.02 and 10.03 have a 20kW demand threshold, whereby the customer must have a measured demand of at least 20 kW within the most recent 12-month period. Customers that do not achieve this demand threshold must take service under Schedule 10.01 (Small General Service). There is no maximum demand for Sections 10.02 and 10.03.

OTP proposes to introduce a maximum demand threshold of 200 kW to Sections 10.02 and 10.03. The addition of the maximum demand threshold is intended to prevent larger, low-load factor customers moving from Large General Service rates (which include relatively higher demand charges) to General Service rates.

Q. WHY IS OTP PROPOSING TO INTRODUCE A MAXIMUM DEMAND THRESHOLD TO ITS GENERAL SERVICE RATES?

A. The threshold is intended to close a potential loophole, whereby larger, low-load factors customers could migrate to General Service rates and achieve bill savings without any changes in electricity usage. It is important that rates be designed in a way that customer bill savings are coupled with behavioral changes that reduce system costs. Without that connection, customers can engage in rate arbitrage, eroding revenues while not producing commensurate cost savings. The shortfall ultimately would need to be borne by other customers.

Q. IS OTP PROPOSING TO ADD LANGUAGE TO SECTIONS 10.02 AND 10.03 OF ITS TARIFFS TO ADDRESS THE MAXIMUM DEMAND THRESHOLD?

A. Yes. OTP proposes to add the following language in both rate schedules:

> The Customer may remain on this schedule if the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed by default on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.

Q. WILL THIS CHANGE BE APPLIED ON A PROSPECTIVE BASIS?

A. Yes. OTP proposes that customers on the Section 10.02 and 10.03 rates as of the date of the Commission's final order in this proceeding be permitted to remain on the rate, even if their measured demand exceeds 200 kW. The maximum demand threshold would be applied only on a prospective basis.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR SECTION 10.02 GENERAL SERVICE.

A. OTP proposes to set the customer charge at slightly below marginal customer-related costs. The facilities charges are set at updated marginal facilities costs. Finally, we are introducing a demand charge per measured kW to improve cost assignments to customers, but at about 25 percent of marginal demand costs. The present and proposed rate components are identified in the table below.

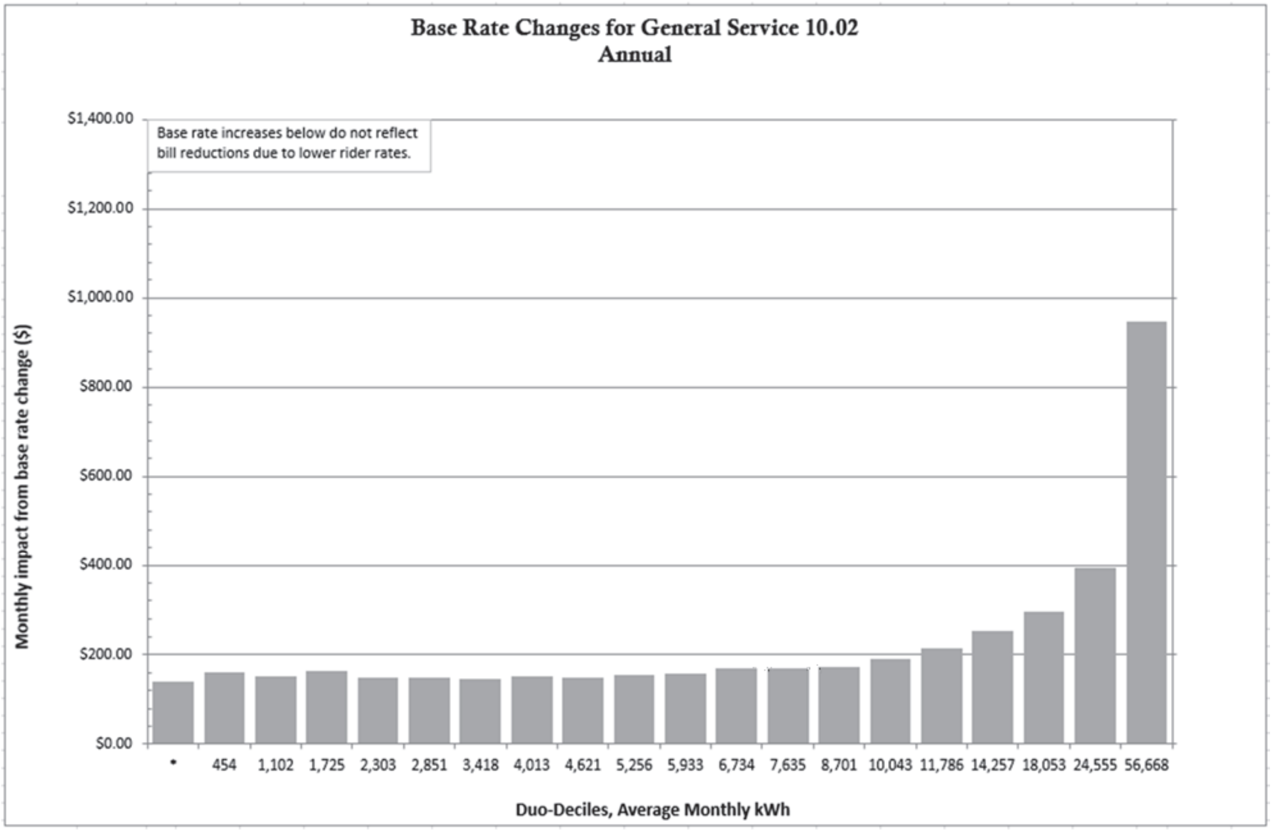
Table 7
Comparison of Current and Proposed 10.02 General Service
(20kW or Greater)
Rate and Marginal Costs

GENERAL SERVICE — Section 10.02 20 KW or Greater	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
Current Rate							
Secondary	$31.90	Cust. + Facilities Charge	$0.98	$0.07506	$0.05078	$ -	$ -
Primary	$21.30	Cust. + Facilities Charge	$0.65 20 kW Minimum	$0.07233	$0.04865	$ -	$ -
Proposed Rate							
Secondary	**$54.00**	**Cust. + Facilities Charge**	**$2.12**	**$0.05259**	**$0.05934**	**$ 2.24**	**$ 2.75**
Primary	**$36.00**	**Cust. + Facilities Charge**	**$1.42** 20 kW Minimum	**$0.05131**	**$0.05757**	**$ 2.15**	**$ 2.62**
Marginal Costs							
Secondary	$54.23	Cust. + Facilities Charge	$2.12	$0.04453	$0.05025	$ 8.96	$ 11.02
Primary	$36.33	Cust. + Facilities Charge	$1.42	$0.04345	$0.04875	$ 8.59	$ 10.47

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED RATE CHANGES TO THIS RATE?

A. About 75 percent of customers have monthly base rate increases of about $200 per month or less.

Figure 5



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.03 GENERAL SERVICE-TIME OF USE RATE.

A. OTP is maintaining the customer charge, despite lower marginal customer costs, increasing distribution facilities charges to marginal cost levels, and not assigning a demand charge during the off-peak period. The present and proposed rate components are identified in the table below.

The proposed rate continues with seasonally differentiated charges and sets the on-peak ("declared peak") energy charges at full marginal cost (i.e., energy plus demand) expected in the hours likely to be defined as system peak hours. The declared peak hours are proposed to move from approximately 100 hours per year to approximately 80 hours per year. The proposed mid-peak and off-peak energy charges are set below marginal energy costs to meet the revenue requirement not satisfied by other charges. This rate structure continues to give a strong, efficient, and transparent price signal to customers during critical hours.

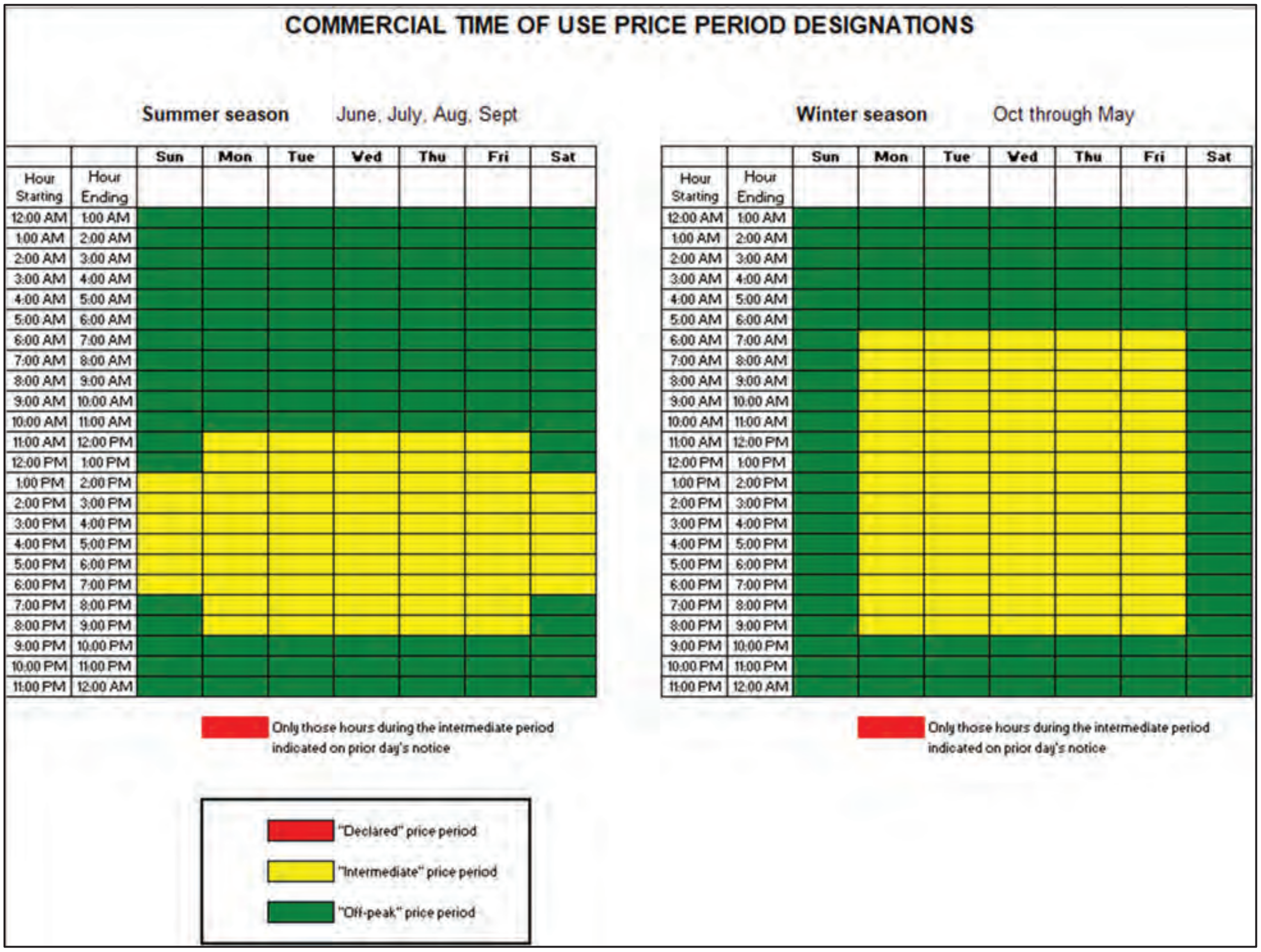
Table 8
Comparison of Current and Proposed 10.03 General Service
Time of Use
Rate and Marginal Costs

GENERAL SERVICE - TIME OF USE — Section 10.03	Customer Charge per month	Minimum Bill per month	Facilities Charge per KW per month		Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer	Demand Charge per kW per mo. Winter
Current Rate							per seasonal max kW	
Seasonal Energy and Demand with Peak, Mid-Peak, Off Peak	$219.00	Cust+Fac. +min. Demand	$0.98	*Declared	$0.43264	$0.16259	NA	NA
				Intermediate	$0.02571	$0.02638	$3.44	$5.12
				Off-peak	$0.01702	$0.01845	$0.00	$0.00
Proposed							per seasonal max kW	
Seasonal Energy and Demand with Peak, Mid-Peak, Off Peak	$219.00	Cust+Fac. +min. Demand	$2.12	*Declared	$0.19539	$0.23215	NA	NA
				Intermediate	$0.03996	$0.04012	$2.57	$6.18
				Off-peak	$0.02607	$0.03452	$0.00	$0.00
					Marginal Energy		Marginal Capacity	
Marginal Costs				Declared	$0.19539	$0.23215	$0.00	$0.00
				Interm.	$0.05368	$0.05389	$2.01	$4.28
	$99.98		$2.12	Off	$0.03502	$0.04637	$0.56	$1.90

Q. ARE YOU PROPOSING TO CHANGE THE TIME OF USE PERIODS FOR THIS RATE?

A. Yes. The changes to the time of use periods are based on the results of the 2024 Marginal Cost Study. The new periods include increased off-peak and intermediate hours. The chart below shows a graphical representation of the new period definitions. Specific period definitions are included in the proposed rate schedule, which is part of Volume 2C.

Figure 6



Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED TIME PERIOD CHANGES IN THE SECTION 10.03 GENERAL SERVICE – TIME OF USE RATE.

A. The changes improve the correlation of expected market prices and the proposed time of day periods. Specifically:

- Summer weekday: added an additional off-peak hour (was shoulder) from 9pm-10pm
- Summer weekend: added additional off-peak hours (were shoulder) from 11am-1pm, 7pm-10pm
- Winter weekday: added additional off-peak (was shoulder) from 9pm-10pm
- Winter weekend: removed all shoulder, now is all off-peak (used to be 4 shoulder hours)

Q. WHAT ARE THE BASE BILL IMPACTS FROM THE PROPOSED 10.03 GENERAL SERVICE-TIME OF USE RATE?

A. A duo decile base bill impact graph was not prepared, as there is only one customer taking service on this rate.

D. Large General Service Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE LARGE GENERAL SERVICE CLASS?

A. There are seven rates within the Large General Service Class: Large General Service (Section 10.04), Large General Service Time of Day (Section 10.05), Super Large General Service (Section 10.06), Standby Service (Section 11.01), Real-Time Pricing Rider (Section 14.02), Large General Service Rider (Section 14.03), Economic Development Rate Rider – Large General Service (Section 14.13).

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. Those rates include the Large General Service (10.04). Large General Service Time of Day (Section 10.05) and the Standby Rate (Section 11.01). I will address the specific restructuring items below.

Q. IS OTP ADDING ANY ADDITIONAL REQUIREMENTS TO THE LARGE GENERAL SERVICE RATES?

A. Yes: we are adding conditions that are intended to work in conjunction with the new 200 kW demand threshold proposed for Sections 10.02 and 10.03. As described earlier, these revisions are all intended to prevent inappropriate rate arbitrage by larger, low-load-factor customers.

Q. PLEASE DESCRIBE THE CONDITIONS BEING ADDED TO THE LARGE GENERAL SERVICE RATES.

A. OTP proposes to add the following language to both Section 10.04 and 10.05:

> The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or 10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.

Q. PLEASE DESCRIBE YOUR BASE RATE DESIGN PROPOSAL FOR THE SECTION 10.04 LARGE GENERAL SERVICE RATE.

A. The present and proposed rate components are identified in the table below. The proposed Section 10.04 rate continues with single block seasonal demand and energy charges. These charges are based on marginal costs. Demand charges are increasing and are set 20 percent higher than marginal capacity cost. Customer charges remain unchanged, but also are higher than marginal customer-related costs. Finally, facilities charges are set at marginal costs, and the energy costs are below marginal energy costs in order to collect the remainder of the revenue requirement. The proposed rate retains the minimum demand at 80 kW, although there is an option for high-load factor customers under 80 kW to pay demand charges based on the minimum demand (80 kW) rather than their measured demand. This allows smaller customers who are unusually efficient to take advantage of a rate that better rewards their efficiency.

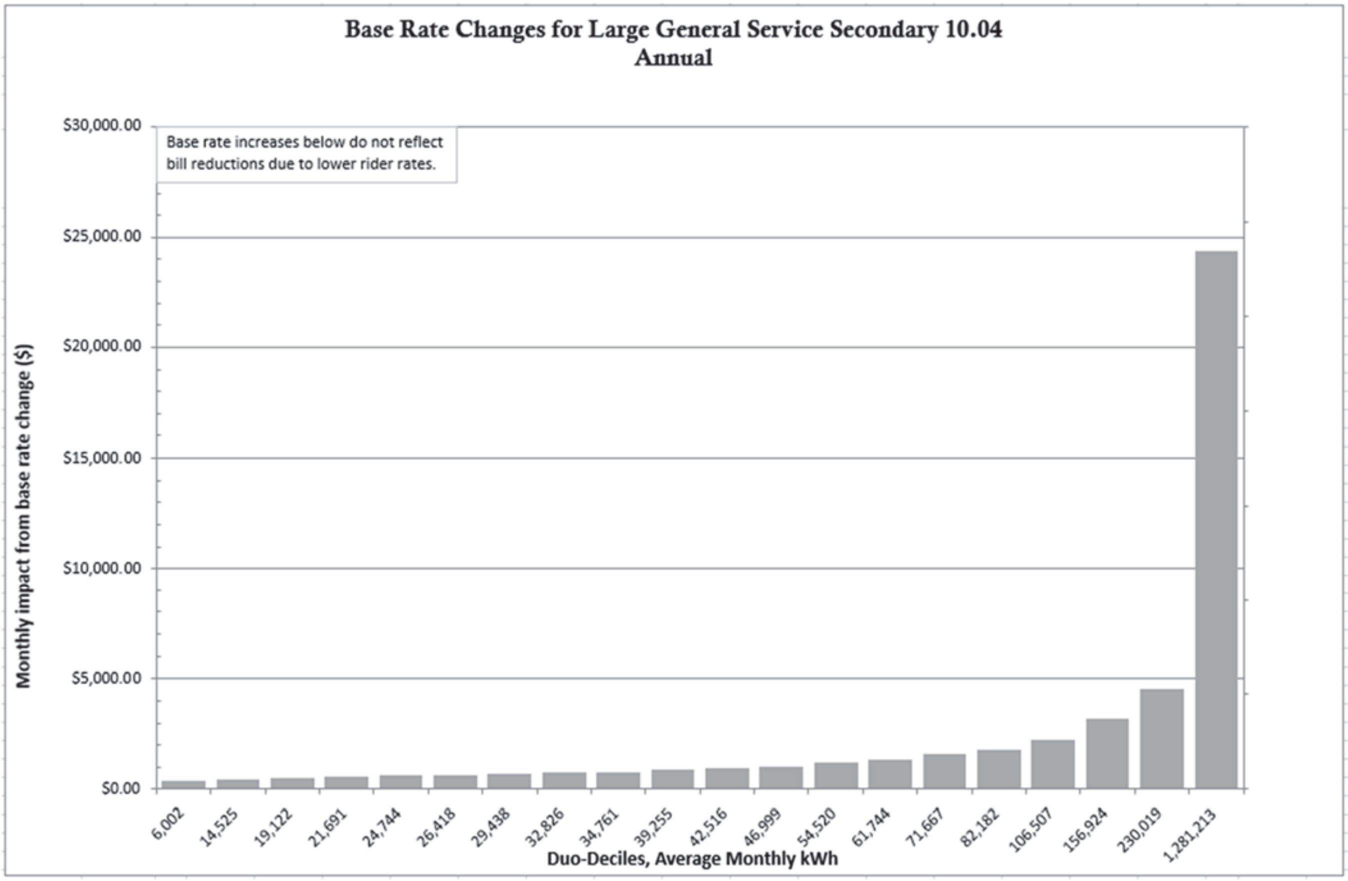
Table 9
Comparison of Current and Proposed 10.04 Large General Service
Rate and Marginal

LARGE GENERAL SERVICE	Section 10.04								
	Customer Charge per month	Minimum Bill per month		Facilities Charge per annual max. kW (minimum 80 kw) per month		Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
SECONDARY 603									
Current Rate	$215.90	Cust+Fac+Demand			All Energy	**$0.02286**	**$0.02341**	**$10.75**	**$8.54**
			< 1000 kW:	$0.76					
			> 1000 kW:	$0.56					
Proposed - Secondary	$215.90	Cust+Fac+Demand			All Energy	**$0.03045**	**$0.04042**	**$10.75**	**$13.22**
			< 1000 kW:	$0.75					
			> 1000 kW:	$0.52					
Marginal Costs	$113.62		< 1000 kW:	$0.75		$0.04453	$0.05911	$8.96	$11.02
			> 1000 kW:	$0.52					
PRIMARY 602						Summer	Winter	Summer	Winter
Current Rate	$282.00	Cust+Fac+Demand		($ per kVA-Month) $0.48	All Energy	$0.02224	$0.02264	$10.35	$8.15
Proposed - Primary	$282.00	Cust+Fac+Demand		$0.52	All Energy	**$0.02971**	**$0.03333**	**$10.31**	**$12.57**
Marginal Costs	$239.31			$0.52		$0.04345	$0.04875	$8.59	$10.47
TRANSMISSION 632						Summer	Winter	Summer	Winter
Current Rate	$282.00	Cust+Fac+Demand		$0.00	All Energy	$0.02103	$0.02121	$8.85	$7.30
Proposed - Transmission	$282.00	Cust+Fac+Demand		$0.00	All Energy	**$0.02901**	**$0.03237**	**$9.54**	**$6.68**
Marginal Costs	$239.31			$0.00		$0.04242	$0.04734	$7.95	$5.57

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 10.04 LGS RATE?

A. The base rate impacts for this class of large customers are in the range of a few hundred to a few thousand dollars. About 80 percent of the customers on the secondary rate will see an increase of about $2,000 or less per month. Due to the small number of customers, no base rate impacts will be shown for the primary voltage customers.

Figure 7



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.05 LARGE GENERAL SERVICE –TIME OF DAY RATE.

A. OTP's proposal for the Large General Service Time of Day (LGS TOD) rate generally continues with the current design. The present and proposed rate components are identified in the table below. The time-differentiated energy and demand charges are adjusted in a similar fashion as those discussed in the Large General Service Section 10.05 rate.

Table 10
Comparison of Current and Proposed 10.05 Large General Service Time of Day Rate and Marginal Costs

LARGE GENERAL SERVICE - TIME OF DAY			Section 10.05													
	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)		Energy Charge per kWh						Demand Charge per kW					
Customer #					Summer			Winter			Summer			Winter		
SECONDARY					PK 611	MP 615	OP 613	PK 611	MP 615	OP 613	PK 611	MP 615	OP 613	PK 611	MP 615	OP 613
Current Rate	$215.90	Cust. + Facilities	$0.76	< 1,000 kW	$0.03527	$0.02683	$0.01776	$0.03090	$0.02753	$0.01925	$7.31	$3.44	$0.00	$5.29	$3.25	$0.00
			$0.57	>=1,000 kW												
Rate 1	$215.90	Cust. + Facilities	$0.76	< 1,000 kW	$0.04847	$0.03948	$0.02576	$0.04348	$0.03964	$0.03411	$7.67	$3.08	$0.00	$5.81	$7.41	$0.00
			$0.57	>=1,000 kW												
Marginal Costs	$108.29		$0.75 $0.65		$0.06589	$0.05368	$0.03502	$0.05911	$0.05389	$0.04637	$6.40	$2.01	$0.56	$4.84	$4.28	$1.90
PRIMARY					PK 610	MP 614	OP 612	PK 610	MP 614	OP 612	PK 610	MP 614	OP 612	PK 610	MP 614	OP 612
Current Rate	$282.00	Cust. + Facilities	$0.48		$0.03422	$0.02612	$0.01738	$0.02981	$0.02665	$0.01871	$7.05	$3.29	$0.00	$5.03	$3.12	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.49		$0.04717	$0.03852	$0.02517	$0.04207	$0.03844	$0.03312	$7.36	$2.96	$0.00	$5.53	$7.04	$0.00
Marginal Costs	$239.31		$0.65		$0.06413	$0.05237	$0.03422	$0.05719	$0.05226	$0.04503	$6.13	$1.93	$0.54	$4.61	$4.06	$1.81
TRANSMISSION					PK 639	MP 637	OP 640	PK 639	MP 637	OP 640	PK 639	MP 637	OP 640	PK 639	MP 637	OP 640
Current Rate	$282.00	Cust. + Facilities	$0.00		$0.03213	$0.02465	$0.01653	$0.02775	$0.02494	$0.01760	$6.11	$2.74	$0.00	$4.58	$2.72	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.00		$0.04600	$0.03760	$0.02460	$0.04076	$0.03732	$0.03219	$6.80	$2.74	$0.00	$2.54	$4.14	$0.00
Marginal Costs	$239.31		$0.00		$0.06253	$0.05112	$0.03344	$0.0554	$0.0507	$0.0438	$5.67	$1.78	$0.50	$2.12	$2.50	$0.95

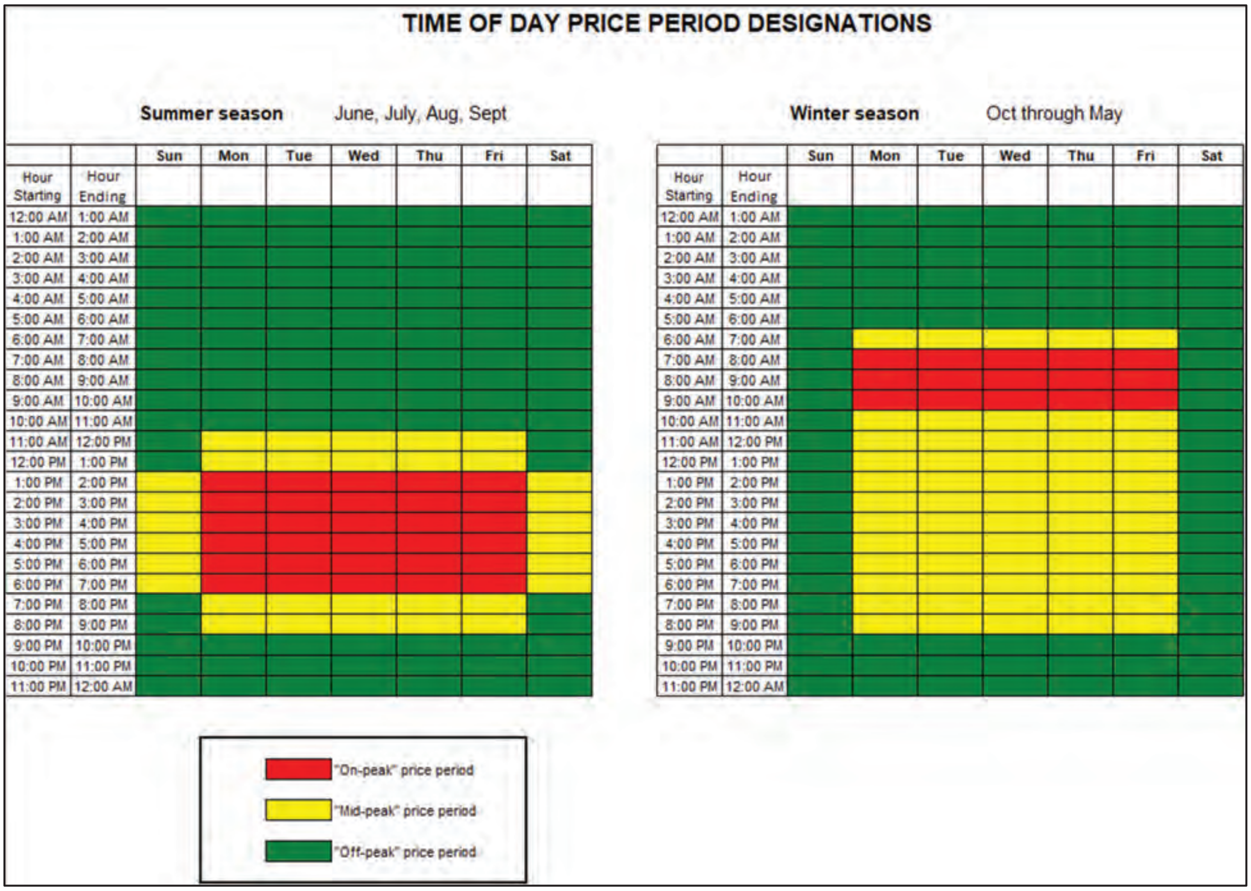
Q. HAVE YOU INCLUDED A BILL IMPACTS ANALYSIS FOR THE 10.05 LARGE GENERAL SERVICE – TIME OF DAY RATE?

A. No. There is currently one customer taking service on this rate. Individualized bill analysis would compromise the privacy of this customer.

Q. ARE YOU PROPOSING TO CHANGE THE TIME OF USE PERIODS FOR THIS RATE?

A. Yes. The changes to the time of use periods are based on the results of the 2024 Marginal Cost Study. The new periods include decreased on-peak hours and increased off-peak and mid-peak (was shoulder) hours. The chart below shows a graphical representation of the new period definitions. Specific period definitions are included in the proposed rate schedule, which are part of Volume 2C.

Figure 8



Q. PLEASE PROVIDE A SUMMARY OF CHANGES TO THE TIME OF USE PERIODS FOR THE SECTION 10.05 RATE.

A. The changes improve the correlation of expected market prices and the proposed time of day periods. Specifically:

- Summer weekday: added an additional off-peak hour (was mid-peak, formerly known as shoulder) from 9pm-10pm
- Summer weekend: added additional off-peak hours (were mid-peak) from 11am-1pm, 7pm-10pm
- Winter weekday:
  - added additional mid-peak, (was on peak) from 10am-11am
  - added additional off-peak (was mid-peak) from 9pm-10pm
- Winter weekend: removed all shoulder, now is all off-peak (used to be 4 mid-peak hours).

Q. IS OTP PROPOSING A TRIAL PERIOD FOR THE SECTION 10.05 LARGE GENERAL SERVICE – TIME OF DAY RATE?

A. Yes. This is another example of our rates restructuring efforts. The proposal offers interested customers a 3-month trial period on this rate. This restructuring proposal is based on one of the five restructuring efforts: Customer-centric/flexibility. The proposed language is included in our proposed rates, and for convenience, shown below:

Proposed Optional Trial Service: Large General Service Time of Day

- Customers may elect Time of Day service for a trial period of three months.
- If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment.
- If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of one year as described in the General Rules and Regulations Section 1.02.
- The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.

Q. ARE THERE ANY OTHER RESTRUCTURING CONSIDERATIONS FOR YOUR LARGE GENERAL SERVICE RATE DESIGNS NOT INCLUDED IN YOUR TESTIMONY?

A. Yes. Due to the number of large customers with high load factors, OTP continues to examine the potential for a high-load-factor rate design class in the future.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.01 STANDBY RATE.

A. OTP proposes to continue with the current design, based on marginal costs, with updated rate levels. The proposed Standby Service rate provides three services under one rate schedule. These services are Backup, Scheduled Maintenance, and Supplemental Service:

- Backup Services is the energy and demand supplied by the utility during unscheduled outages of a Customer's generator.
- Scheduled Maintenance Service is the energy and demand supplied by the utility during scheduled outages of a Customer's generator.
- Supplemental Service is the energy and demand supplied by the utility in addition to the capability of the on-site generator.

Table 11
Comparison of Current and Proposed Standby Service
Rate and Marginal Costs

Standby Service		11.01													
	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh						Demand Charge per kW					
				Summer			Winter			Summer			Winter		
				PK	SH	OP	PK	SH	OP	PK	SH	OP	PK	SH	OP
SECONDARY															
Current Rate	$242.24	Cust. + Facilities	$0.55000	0.05351	0.03507	0.00950	0.04074	0.03557	0.01596	$0.54794	$0.00	$0.00	$0.43005	$0.00	$0.00
		Reserve Charge per kW		$0.6564			$0.2235			$0.5479			$0.4301	$ per kW per day	
Proposed	$105.33	Cust+Reservation+Facilities	$1.0260	$0.03462	$0.02935	$0.01995	$0.03540	$0.03313	$0.02539	$0.6577	$0.00	$0.00	$0.4117	$0.00	$0.00
		Reserve Charge per kW		$1.7535			$0.0400			$0.6577			$0.4117	$ per kW per day	
Marginal Costs	$105.33		$1.03	$0.03385	$0.02870	$0.01950	$0.03462	$0.03240	$0.02483	$0.66	$0.00	$0.00	$0.41	$0.00	$0.00
PRIMARY															
Current Rate	$304.33	Cust. + Facilities	$0.45000	$0.05063	$0.03305	$0.00851	$0.03784	$0.03307	$0.01443	$0.5246	$0.00	$0.00	$0.4080	$0.00	$0.00
		Reserve Charge per kW		$0.1604			$0.0510			$0.5246			$0.4080	$ per kW per day	
Proposed	$437.30	Cust+Reservation+Facilities	$0.6915	$0.03370	$0.02859	$0.01951	$0.03425	$0.03212	$0.02465	$0.6838	$0.00	$0.00	$0.7003	$0.00	$0.00
		Reserve Charge per kW		$1.6786			$0.0380			$0.6297			$0.3904	$ per kW per day	
Marginal Costs	$437.30		$0.69	$0.03295	$0.0280	$0.01908	$0.03350	$0.03141	$0.02411	$0.63	$0.00	$0.00	$0.39	$0.00	$0.00
TRANSMISSION															
Current Rate	$304.33	Cust. + Facilities	$0.00	$0.04604	$0.02982	$0.00690	$0.03333	$0.02916	$0.01202	$0.6367	$0.00	$0.00	$0.6433	$0.00	$0.00
		Reserve Charge per kW		$0.5842			$0.1990			$0.4881			$0.3742	$ per kW per day	
Proposed	$437.30	Cust+Reservation+Facilities	$0.00	$0.03286	$0.02790	$0.01911	$0.03323	$0.03121	$0.02399	$0.4881	$0.00	$0.00	$0.3742	$0.00	$0.00
		Reserve Charge per kW		$1.5607			$0.0349			$0.5858			$0.3578	$ per kW per day	
Marginal Costs	$437.30		N/A	$0.0321	$0.02729	$0.01869	$0.0325	$0.0305	$0.0235	$0.59	$0.00	$0.00	$0.36	$0.00	$0.00

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 11.01 STANDBY SERVICE RATES?

A. OTP has one North Dakota customer currently taking Standby Service. Again, individualized bill analysis would compromise the privacy of the customer.

Q. IS OTP PROPOSING ANY OTHER REVISIONS TO THE SECTION 11.01 RATE?

A. Yes. OTP is proposing minor language restructuring improvements to the Standby rate schedule, including:

- Included Supplemental Demand charges in the rate versus referencing the Large General Service Time of Day (10.05) rate schedule;
- Added language to ensure contracted backup demands are kept current and both company and customer are engaged in changes occurring with the services provided; and
- Added additional definitions.

In Section VII, below, I also address changes related to Standby service regarding partial requirements customers.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.06 SUPER LARGE GENERAL SERVICE RATE.

A. OTP's Super Large General Service (SLGS) rate offering primarily is targeted at attracting high-load-factor large commercial customers to OTP's service territory. Qualifying customers have access to individual contract pricing based on OTP's marginal cost of service, though that pricing must ensure net benefits to other customers. OTP currently has one customer, APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain), taking service under the SLGS tariff.[4] We are proposing to update Applied's individual contract pricing for the reasons discussed by OTP witness Mr. Bruce G. Gerhardson in his Direct Testimony. Given the proprietary nature of Applied's pricing, the updated rates are being provided directly to Applied, though the resulting revenue change can be identified in Schedule E-2 of Volume 3, Supporting Information.

Q. HOW DID YOU DEVELOP THE UPDATED INDIVIDUALIZED PRICING FOR THE CUSTOMER TAKING SERVICE UNDER THE SLGS RATE?

A. Contract pricing offered under the SLGS tariff is customized for the individual customer based on their specific load characteristics and investment needed to serve the customer. SLGS customers pay rates based on marginal costs rather than embedded costs. We developed individualized pricing for Applied based on these principles and that pricing was approved by the Commission in Case No. PU-21-366.

The revised pricing for Applied continues to adhere to the principles of the SLGS tariff in that it reflects Applied's specific load characteristics and investment needed to serve the customer. It also reflects updated marginal costs, as measured in the 2024 Marginal Cost Study. Finally, the revised pricing maintains approximately the same allocation of net benefits between Applied and other customers that was present in Case No. PU-21-366.

[4] *See* Case Nos. PU-21-364, 21-365, 21-366.

E. Irrigation Class

Q. WHAT RATE SCHEDULES ARE IN THE IRRIGATION SERVICE CLASS?

A. There is only one rate schedule in the Irrigation Class, the Irrigation Service (Section 11.02). However, there are two service options offered under this rate.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.02 IRRIGATION SERVICE RATE.

A. The present and proposed rate components are identified in the table below.

Table 12
Comparison of Current and Proposed 11.02 Irrigation Service Option 1 & 2 Rate and Marginal Costs

Section 11.02

Irrigation Option #1 | Irrigation Option #2

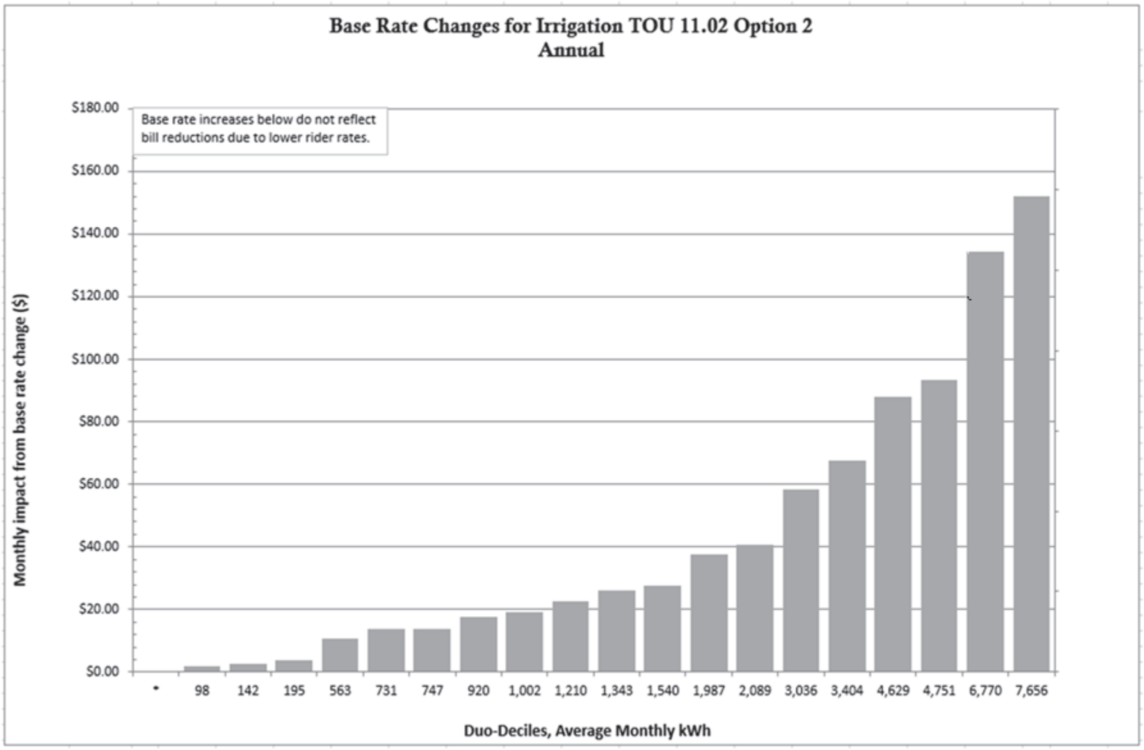
SECONDARY	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per HP Summer	Demand Charge per HP Winter
Current Rate	$24.30	Cust +Fac	Customer Specific	$0.04533	$0.02633	N/A	N/A
OPTION 1							
Proposed Rate	$24.30	Customer + Facilities	Customer Specific	$0.06073	$0.04173	N/A	N/A
Marginal Costs	$35.62			$0.05677	$0.06444	N/A	N/A

	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Summer Declared Peak (per kWh)	Energy Summer Intermediate (per kWh)	Energy Summer Off Peak (per kWh)	Energy Winter Declared Peak (per kWh)	Energy Winter Intermediate (per kWh)	Energy Winter Off-Peak (per kWh)	Demand Summer Declared Peak (per kW)	Demand Summer Intermediate (per kW)	Demand Summer Off-Peak (per kW)	Demand Winter Declared Peak (per kW)	Demand Winter Intermediate (per kW)	Demand Winter Off-Peak (per kW)
Current Rate	$24.30	Cust +Fac	Customer Specific	$0.17685	$0.03274	$0.01420	$0.12867	$0.03050	$0.01457	N/A	N/A	N/A	N/A	N/A	N/A
OPTION 2															
Proposed Rate	$24.30	Cust +Fac	Customer Specific	$0.18683	$0.05653	$0.03085	$0.22632	$0.05960	$0.04348	N/A	N/A	N/A	N/A	N/A	N/A
Marginal Costs	$35.62			$0.18683	$0.06648	$0.03628	$0.22632	$0.07009	$0.05113						

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED IRRIGATION SERVICE RATE (SECTION 11.02)?

A. The base rate impacts for Option 1 (non-time of use) are not provided in order to protect the privacy of the customers (fewer than 20) on this rate option Option 2 is a time of use rate which allows irrigation customers to participate in the same manner as described in Section 10.03 rate. The base rate impacts for this rate result in 75 percent of the customers with impacts less than $60. Like the discussion in Section 10.03, all customer impacts can vary depending upon the mid-peak and off-peak usage of the customers. Because the impacts represented in the graph are determined based on customers' usage patterns and because the purpose of time of use rates such as this one are to incentivize customer usage based on the price signals being sent by the particular rate design, it is reasonable to expect that actual customer impacts may be less than represented here by responding to the price signals incorporated into the rate.

Figure 9



Q. IS ONE OF YOUR RESTRUCTURING PROPOSALS CHANGING HOW NEW IRRIGATION CUSTOMERS PAY FOR THEIR UNIQUE FACILITIES?

A. Yes. I will provide further details of the special facilities charge proposal later in my testimony.

F. Outdoor Lighting Class

Q. WHAT RATE SCHEDULES ARE IN THE LIGHTING SERVICE CLASS?

A. There are three rates in the Outdoor Lighting Class: Outdoor Lighting – Energy Only (Section 11.03), Outdoor Lighting (Section 11.04), and LED Street and Area Lighting – Dusk to Dawn (Section 11.07).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE (RATE CODES 748 AND 749).

A. OTP's proposal is shown in the table below.

Table 13
Comparison of Current and Proposed 11.03 Outdoor Lighting Energy-Only Rate and Marginal Costs

ND Energy Only Lighting - 11.03

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh
Metered				
Current Rate	$2.00	$2.00	$0.00	0.06681
Proposed Rate	$2.00	$2.00	$0.00	0.07821
Marginal Costs	$3.59		$0.00	$0.04934
Non-Metered				
Current Rate	Connected kW x	$22.83	Current rate * 4100 hrs in year / 12 months	
Proposed Rate	Connected kW x	$23.42	Current rate * 4100 hrs in year / 12 months	

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE?

A. The overall base rate impacts for the rate are 2.61 percent.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.04 OUTDOOR LIGHTING RATE.

A. The 11.04 Outdoor Lighting Rate proposal continues to operate as a closed rate since these are non-LED services. OTP is continuing its LED change-out program and is scheduled to complete all LED installations by end of 2028. The table below contains expected current base and proposed base revenues for non-LED fixtures. Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 14

ND Energy Only Lighting - 11.04		
	STREET, AREA, and FLOOD LIGHTING	
Current Revenue	Proposed Revenue	Increase
$ 900,453	$ 950,046	$ 49,593

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 11.04 OUTDOOR LIGHTING RATE?

A. The base rate impacts for each current lighting fixture are the same, 5.51 percent (i.e., different than overall revenue as we have different light fixture types and quantities).

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 11.07 OUTDOOR LIGHTING RATE?

A. The base rate impacts for each closed and current lighting fixture are the same, 0.92 percent (i.e., different than overall revenue as we have different light fixture types and quantities). Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 15

ND LED STREET and AREA LIGHTING - DUSK TO DAWN 11.07		
	STREET, AREA, and FLOOD LIGHTING	
Current Revenue	Proposed Revenue	Increase
1,558,539	1,572,920	$14,866

G. Other Public Authority Service Class

Q. WHAT RATE SCHEDULES ARE IN THE OTHER PUBLIC AUTHORITY SERVICE CLASS?

A. There are two rates in the Other Public Authority Class: Municipal Pumping Service (Section 11.05) and Civil Defense – Fire Siren Service (Section 11.06).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE MUNICIPAL PUMPING SERVICE.

A. The present and proposed rate components are identified in the table below.

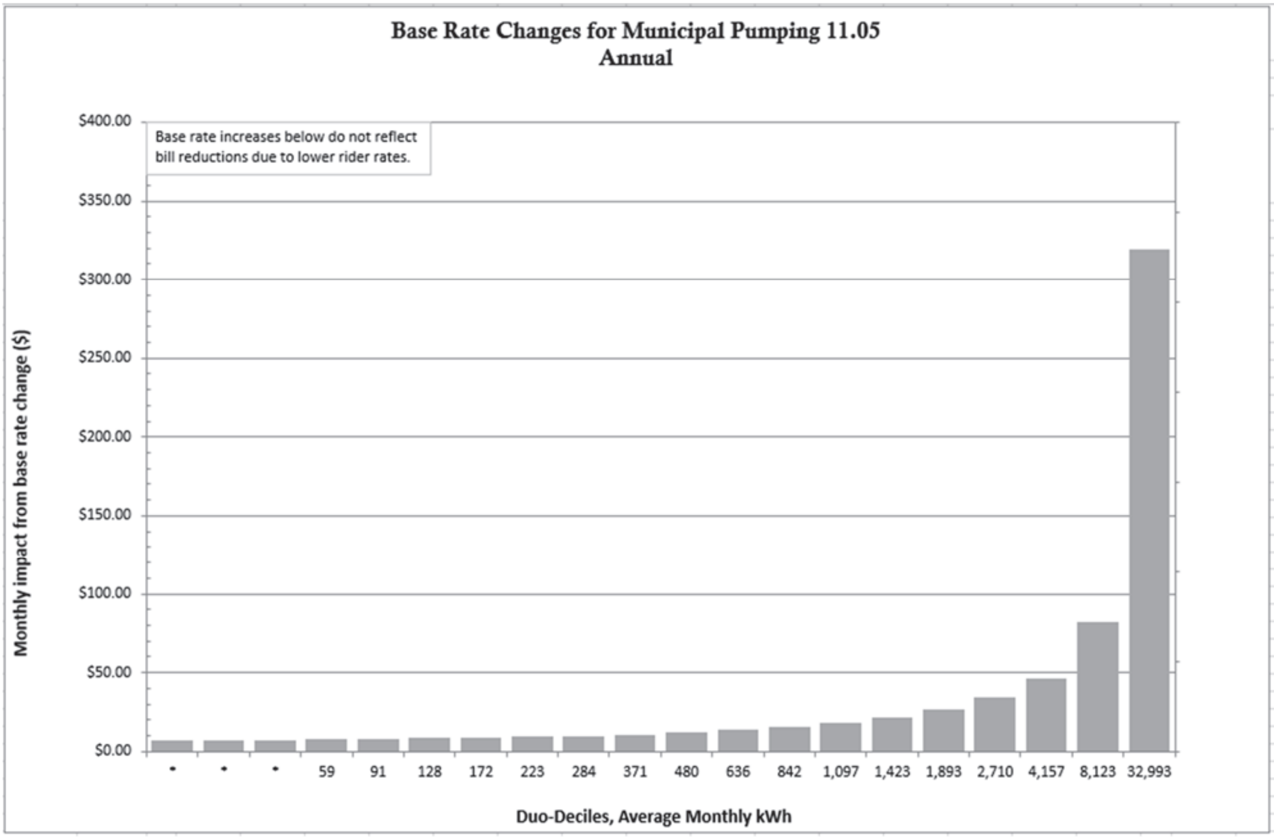
Table 16
Current and Recommended 11.05 Municipal Pumping Rates and Marginal Costs

Municipal Pumping	Section 11.05						
		Comparison of Current Rate, Recommended Rate and Marginal Cost Municipal Pumping					
		Customer $ per month	Minimum Bill $ per month		Facilities Charge $ per month	Summer $ per kWh per month	Winter
Current Rate	Secondary	$26.50	Cust + Fac	per kW	$0.65	$0.04599	$0.03111
	Primary	$26.50	Cust + Fac	per kW	$0.65	$0.04432	$0.02981
Proposed Rate	Secondary	$33.45	Cust + Fac	**per KW**	**$2.12**	$0.04209	$0.04778
	Primary	$33.45	Cust + Fac	**per KW**	**$1.42**	$0.04091	$0.04679
Marginal Costs		$33.45		Secondary	$2.12		
				Primary	$1.42		
					Energy & Demand		
All Season				Secondary	$0.05677	$0.06444	
				Primary	$0.05518	$0.06311	

Q. WHAT ARE THE BASE RATE IMPACTS OF YOUR RECOMMENDED SECTION 11.05 MUNICIPAL PUMPING RATE?

A. Base rate impacts vary, as the consumption levels of customers vary significantly under this rate. About 90 percent (18 duo-deciles) of customers have base rate impacts of less than $50.00 per month.

Figure 10



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.06 CIVIL DEFENSE-FIRE SIREN SERVICE RATE.

A. The proposed Civil Defense-Fire Siren Rate components are shown below.

Table 17
Current and Recommended 11.06 Civil Defense-Fire Sire Service Rate and Marginal Cost

Section 11.06
ND Civil Defense Fire Sirens

SECONDARY	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Charge per HP
Current Rate	$1.00	Customer Charge	$0.00	$0.53193
Proposed Rate	$1.22	Customer Charge	$0.00	$0.71789
Marginal Costs	$0.30			$0.04687 $/kWh

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED CIVIL DEFENSE-FIRE SIREN SERVICE RATE SCHEDULE?

A. The base rate impacts are presented in a simple monthly bill comparison in below. The greatest monthly base rate bill dollar impact is $5.77 per month. Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 18
Monthly Base Bill Impacts – 11.06 Civil Defense-Fire Siren Service

Siren HP	Monthly Impacts			
	Current Bill	Proposed Bill	Difference	% Change
12.5	$ 6.59	$ 10.19	$ 3.60	55%
1	$ 1.65	$ 1.94	$ 0.29	17%
1.5	$ 1.86	$ 2.30	$ 0.43	23%
10	$ 5.52	$ 8.40	$ 2.88	52%
2	$ 2.08	$ 2.66	$ 0.58	28%
2.5	$ 2.29	$ 3.01	$ 0.72	31%
20	$ 9.81	$ 15.58	$ 5.77	59%
3	$ 2.51	$ 3.37	$ 0.86	34%
3.5	$ 2.72	$ 3.73	$ 1.01	37%
4.5	$ 3.15	$ 4.45	$ 1.30	41%
5	$ 3.37	$ 4.81	$ 1.44	43%
6.5	$ 4.01	$ 5.89	$ 1.87	47%
7	$ 4.23	$ 6.25	$ 2.02	48%
7.5	$ 4.44	$ 6.60	$ 2.16	49%

H. Controlled Service Deferred Load Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE DEFERRED LOAD SERVICE CLASS?

A. There are two rates in the Controlled Service Deferred Load Class, the Water Heating – Controlled Service Rider (Section 14.01) and Controlled Service – Deferred Load Rider (Section 14.06).

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. Both rates were placed into one customer class to create alignment of rate classes within the appropriate customer class. They are better aligned in one customer class because of the nature of their operations during control periods and similarities in their load profiles. This also results in improved cost allocations.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.01 WATER HEATING-CONTROLLED SERVICE RIDER.

A. The proposal for the Metered Water Heating Control Service shown in the table below increases the customer charge to approximately 78 percent of marginal cost, retains the current method for calculating the minimum bill, and sets both seasonal energy charges at levels necessary to match rate revenues to the rate's revenue requirement. A facilities charge was added to collect a portion (under 10 percent) of the marginal facilities costs. The marginal costs of providing service to customers on this rate are lower than the marginal cost for standard rates because OTP controls the water heaters during high-cost periods.

Table 19
Current and Proposed 14.01 Water Heating-Controlled Service Rider
Rate and Marginal Costs

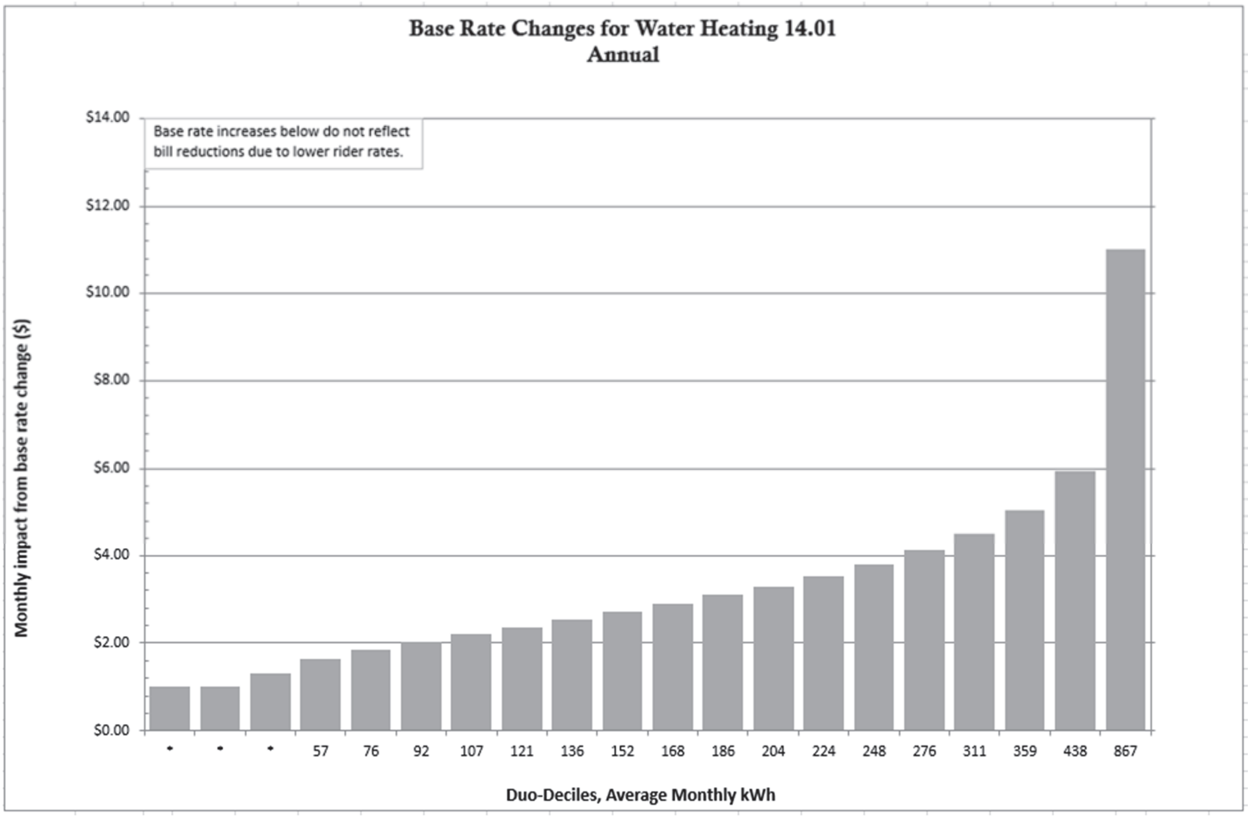
Water Heating Control (Off-Peak)		Section 14.01				
		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current	Customer Charge, Seasonal Energy	$4.00	Cust. + Facilities	$2.00	$0.03078	$0.02661
Proposed Rate	Customer Charge, Seasonal Energy	$5.00	Cust. + Facilities	$2.00	$0.03813	$0.03950
Marginal Costs		$6.45		$24.87	$0.05825	$0.06035

The Water Heating Control Service Credit (Rate Code 192) is essentially a direct load-control program similar to direct load-control of central air conditioners. Under the rate, in exchange for allowing OTP to interrupt the water heating service during high-cost periods, OTP compensates the customer in the form of a bill credit. The credit continues at $8.00 per month.

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 14.01 WATER HEATING-CONTROLLED SERVICE RIDER?

A. Under OTP's proposal, shown in the figure below, 95 percent of Metered Water Heating Control Service customers see a monthly increase of about $6.00. The base rate impacts for the Water Heating Control Service Credit (Rate Code 192), not shown in the figure below, will continue to reduce the customers' standard firm service total bill by $8.00 per month. The impact of the $8.00 credit is reflected in the duo-deciles for the appropriate firm service rates (*e.g*. Residential Service, Figure 1, above).

Figure 11



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.06 CONTROLLED SERVICE – DEFERRED LOAD RIDER

A. The proposal for the Controlled Service – Deferred rate is shown in the table below. It increases the customer charge to approximately 60 percent of marginal cost, retains the current method for calculating the minimum bill, and sets both seasonal energy charges at levels necessary to match rate revenues to the rate's revenue requirement. The facilities charge remains unchanged. The marginal costs of providing service to customers on this rate are similar to the water heating marginal costs.

Table 20

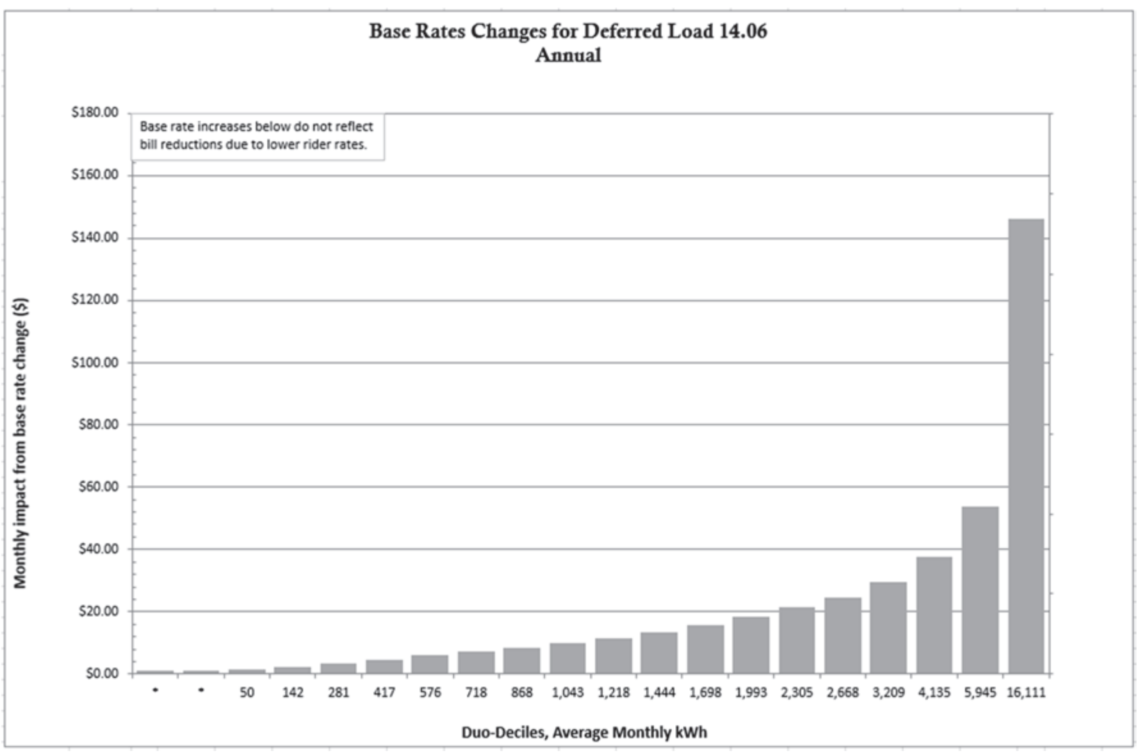
Current and Proposed 14.06 Controlled Service – Deferred Load
Rate and Marginal Costs

Controlled Service - Deferred Load	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per month		Energy Charge per kWh Summer	Energy Charge per kWh Winter
Section 14.06							
Current Deferred Load Rate	$8.80	Customer Charge+Facilities	Flat charge per month	$11.60	All kWhs	$0.02602	$0.02371
					Penalty kwhs	$0.35916	$0.16537
Proposed Rate	$10.00	Customer Charge+Facilities	Flat charge per month	$11.60	All kWhs	$0.04346	$0.03190
					Penalty kwhs	$0.17726	$0.18221
Marginal Costs	$16.76		Urban	$14.93		$0.05486	$0.04026
			Rural	$49.75		$0.17726	$0.18221

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 14.06 DEFERRED-CONTROLLED SERVICE RIDER?

A. Under OTP's proposal, shown in the figure below, 80 percent of the customers will see less than a $22 per month increase. The average customer in this rate class uses more than 5 times the amount of energy as compared to the Water Heater rate class.

Figure 12



I. Controlled Service – Interruptible Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE CONTROLLED SERVICE - INTERRUPTIBLE CLASS?

A. There are two current rates in the Interruptible Service Class: Controlled Service – Interruptible Load CT Metering (Section 14.04) Rider and Controlled Service – Interruptible Load Self-Contained Metering (Section 14.05) Rider.

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. We are proposing to combine Schedules 14.04 and 14.05 into a single rate schedule for customer convenience and simplicity. Therefore, Section 14.05 is proposed to be removed as described in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.04 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER, OPTION 1.

A. The proposed Controlled Service – Option 1 Rider, shown in the table below, includes increases to customer and facilities charges. The facilities charge is set at 100 percent of marginal costs. The energy rate is at about 95 percent of marginal costs. The penalty rate for energy consumed during control periods is based on the total marginal cost over a year and separated into summer and winter seasons. The penalty rate per kWh has been calculated based on the hourly marginal costs during periods usage would be controlled. Fundamentally, the penalty rate charges customers for unauthorized use during control periods.

Table 21
Current and Proposed
Option 1 Controlled Service-Interruptible Load (CT Metering) Rider 14.04
Rate and Marginal Costs

Large Dual Fuel - Option 1	Section 14.04					
Controlled Service - Interruptible - (assumes all customers have CT metering)						
	Customer Charge per month	**Monthly Minimum Bill per month**	**Facilities Charge**	**Energy Charge per kWh**	**Summer**	**Winter**
Current Rate	$20.20	Cust. + Facilities	$0.76 per kW	All kWh	$0.01064	$0.01009
				Penalty kWh	$0.41350	$0.14322
Proposed Rate	$20.20	Cust. + Facilities	$2.12 per kW	All kWh	$0.01388	$0.01203
				Penalty kWh	$0.18412	$0.20847
Marginal Costs	$16.76	<300 kW	$2.12	All kWh	$0.01462	$0.01268
		>=300 kW	$2.12	Penalty kWh	$0.18412	$0.20847

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.04 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER, OPTION 2.

A. As shown in the table below, the facilities charge is set at 100 percent of marginal costs, while the energy rate is at about 95 percent of marginal costs. The penalty rate described above in reference to Option 1 also applies to Option 2 for unauthorized use during control periods.

Table 22
Current and Proposed
Option 2 Controlled Service-Interruptible Load (CT Metering) Rider
Section 14.04
Rate and Marginal Costs

Large Dual Fuel - Option 2	Section 14.04

Controlled Service-Interruptible (assumes all customers have CT metering)

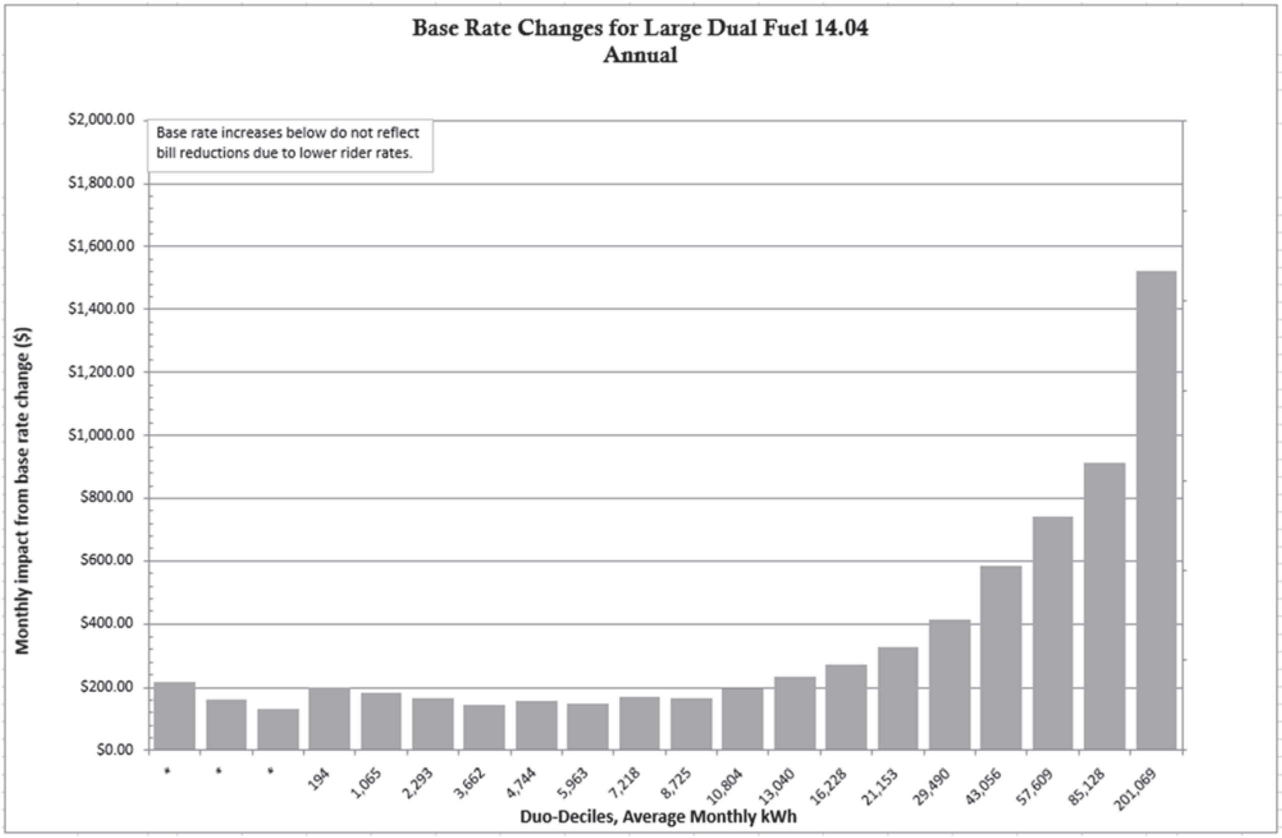
CURRENT RATE OPTION 2	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
Secondary Seasonal Energy, kW Facilities All kWh	$20.20	Customer + Facilities charge	($ per Month)	$0.01064	$0.01009	$11.30	$8.49
		per kW	$0.76				
SECONDARY							
Proposed Rate	$20.20	Customer + Facilities charge	per annual max. kW per month	$0.01388	$0.01203	$10.75	$13.22
		per kW	$2.12				
Marginal Costs	$16.76	<300 kW	$2.12	$0.01462	$0.01268	$ 8.96	$ 11.02
		>=300 kW	$1.42	(Plus 5% firm energy charge)			

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.04 CONTROLLED INTERRUPTIBLE LOAD (CT METERING) RIDER – OPTIONS 1 AND 2?

A. As shown in the figure below, the proposed rate for Option 1 shows 65 percent of the customers with average annual monthly increases around $200.

The proposed rate for Option 2 shows a rate class increase of 79 percent. Only 11 customers represent this rate class, so no duo decile is available.

Figure 13



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION14.05 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (SELF-CONTAINED METERING) RIDER.

A. OTP's proposal for this rate, as shown in the table below, maintains the customer and facilities charges, and sets both seasonal energy charges below marginal costs. The penalty for energy used during a control period is intended to deter customers from unauthorized use during control periods.

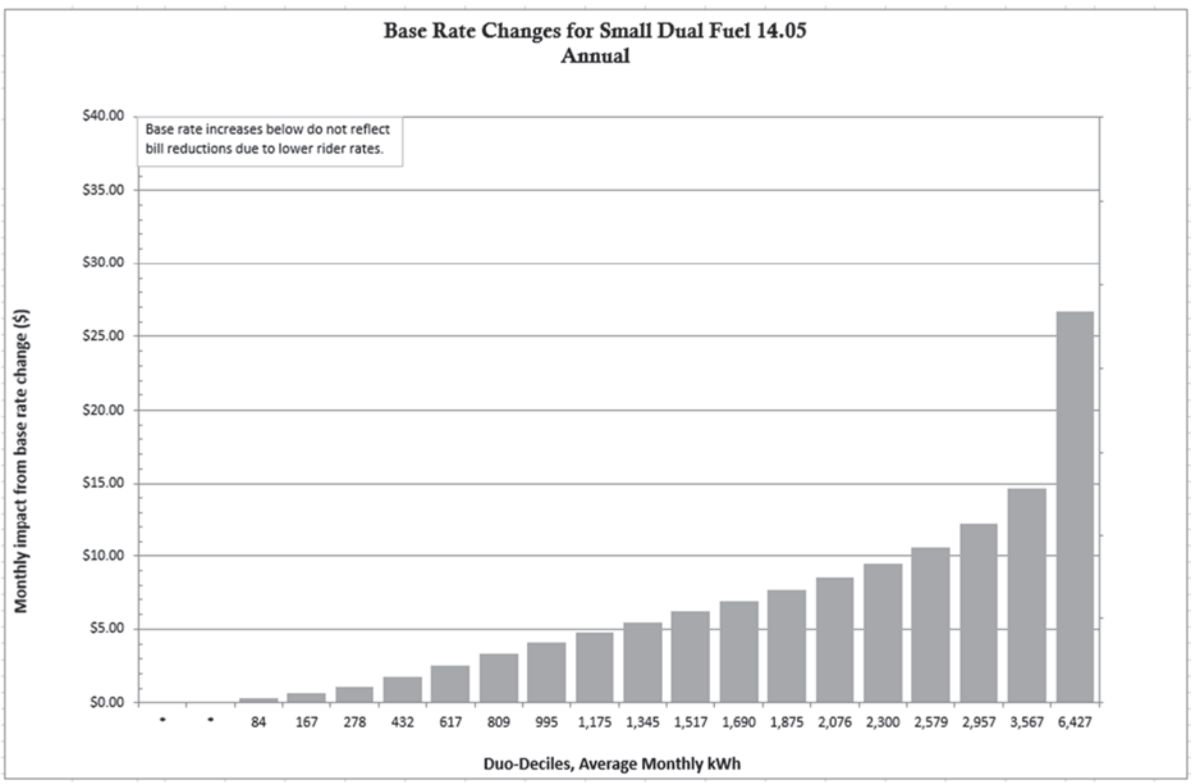
Table 23
Current and Proposed 14.05 Controlled Service-Interruptible Load (Self-Contained) Rider
Rate and Marginal Costs

Small Dual Fuel - Self Contained Metering	Section 14.05						
Controlled Service - Interruptible - SDF, Self-Contained: (assumes all customers do not have CT metering)							
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per customer per month		Energy Charge per kWh	Summer	Winter
Current Rate	$8.50	Cust. + Facilities Charge	Fixed Facilities	$11.70	All kWhs	$0.00911	$0.00850
					Penalty kWhs	$0.41350	$0.17038
Proposed Rate	$8.50	Cust. + Facilities Charge	Fixed Facilities	$11.70	All kWhs	$0.01441	$0.01249
					Penalty kWhs	$0.18412	$0.20847
Marginal Costs	$5.74		<5000 kWh in all months	$11.69	All kWhs	$0.01462	$0.01268
			> 5000 kWh in any month	$46.11	Penalty kWhs	$0.18412	$0.20847

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.05 CONTROLLED INTERRUPTIBLE LOAD (SELF-CONTAINED) RIDER?

A. The figure below shows about 80 percent of the class customers have annual average base rate impacts under $10.00 per month.

Figure 14



J. Controlled Service Off-Peak Class

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.07 FIXED TIME OF SERVICE RIDER.

A. The proposed Fixed Time of Service rider increases customer charges for all voltages, bringing those charges closer to marginal costs. As shown in the table below, the seasonal energy charges are approximately equal to marginal costs expected in the hours when customers will receive service under the rider.

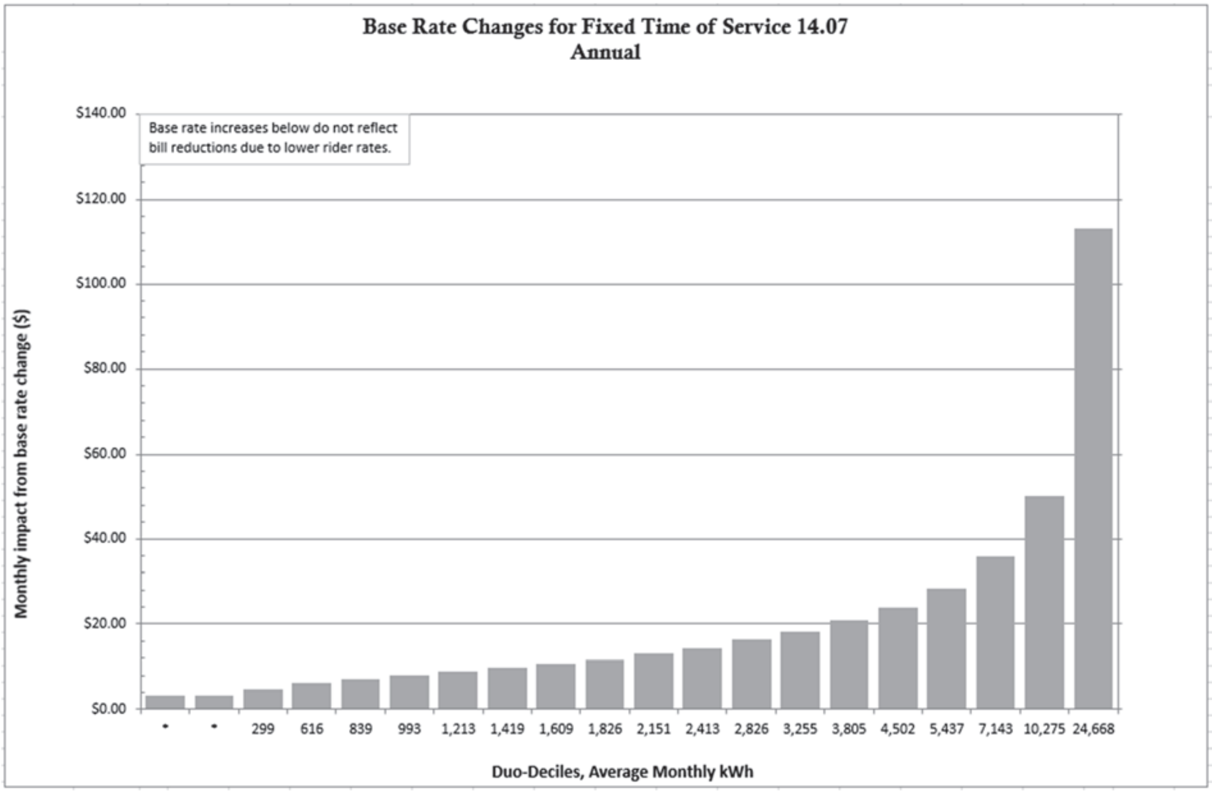
Table 24
Current and Recommended 14.07 Fixed Time of Service Rider
Rate and Marginal Costs

Fixed Time of Service — Section 14.07	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per Customer per month		Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current Rate		Customer + Facilities Charge			**Summer**	**Winter**
Secondary Self-Contained Metering (301)	$6.70		$6.00		$0.01439	$0.01591
				Penalty kWh	$0.06736	$0.04602
Secondary CT Metering (302)	$6.70		$38.00		$0.01439	$0.01591
				Penalty kWh	$0.06736	$0.04602
Primary (303)	$6.70		$18.00		$0.01433	$0.01585
				Penalty kWh	$0.06736	$0.04602
Proposed Rate		Customer + Facilities Charge			**Summer**	**Winter**
Secondary Self-Contained Metering (301)	$10.00		$6.00		$0.01560	$0.02056
				Penalty kWh	$0.07432	$0.07601
Secondary CT Metering (302)	$10.00		$38.00		$0.01560	$0.02056
				Penalty kWh	$0.07432	$0.07601
Primary (303)	$10.00		$18.00		$0.01554	$0.02048
				Penalty kWh	$0.07432	$0.07601
Marginal Costs			$ per a month			
Secondary Self-Contained Metering (301)	$16.76		$21.25		$0.02588	$0.03411
				Penalty kWh	$0.07432	$0.07601
Secondary CT Metering (302)	$16.76		$106.72		$0.02588	$0.03411
				Penalty kWh	$0.07432	$0.07601
Primary (303)	$16.76		$74.77		$0.02578	$0.03398
				Penalty kWh	$0.08986	$0.09649

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.07 FIXED TIME OF SERVICE RIDER?

A. The figure below shows varied base rate impacts for all customers on the proposed Fixed Time of Service Rider, most of the customers will see a bill increase of less than $20 per month.

Figure 15



Q. ARE THERE RESTRUCTURING EFFORTS IN 14.08 - AIR CONDITIONING CONTROL RIDER?

A. Yes. In addition to updating the credit payment, OTP proposes to create an extended cooling season for energy and demand control in order for the Company to control costs further and provide those benefits to participating customers.

Q. PLEASE FURTHER DESCRIBE YOUR PROPOSAL.

A. OTP proposes to increase the monthly energy curtailment from four months (June-September) to six months (May – October) and increase the compensation credit frequency from four months to five months. Total compensation will increase from $32 for four months to $40 for six months.

VI. OTHER RATE OFFERINGS

Q. ARE THERE ANY OTHER PROPOSED RATES IN YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. OTP is proposing certain revisions to Section 5.02 – Special Facilities that will impact service under two retail rate schedules: Sections 11.02 -Irrigation and 14.02 - Bulk Interruptible Service.

Q. PLEASE DESCRIBE SECTION 5.02 – SPECIAL FACILITIES.

A. Section 5.02 – Special Facilities addresses charges to customers for unique extensions and certain non-standard equipment installation to provide service to our customers.

Q. WHAT CHANGES IS OTP PROPOSING TO THE SPECIAL FACILITIES CHARGE RATES?

A. OTP is proposing to implement a rate formula to recover costs associated with equipment installations. The rate formula includes the following cost components:

1. Operations and Maintenance expense for distribution function assets, including allocated administrative and general expenses to support distribution function assets.
2. General and Common Depreciation Expenses allocated to support distribution function assets.
3. Taxes other than income taxes for distribution function assets.
4. Depreciation expense for distribution assets.
5. Income taxes
6. Return on rate base calculated with the approved capital structure.

The inputs for the formula rate template come from FERC Form 1, while the income tax inputs come from MISO Attachment O using actual results for the prior year, which aligns with the FERC Form 1 reporting.

Q. HOW IS THIS DIFFERENT THAN THE CURRENT PRACTICE?

A. The existing practice is to request rate changes only during rate cases.

Q. WHY IS THIS CHANGE BEING PROPOSED?

A. OTP files rate cases relatively infrequently. For example, this is only OTP's third rate case since 2000. Due to changing economic conditions, having an annual rate update through a formula template is more reflective of the actual costs being incurred and subsequently requested for recovery.

Q. IF APPROVED, HOW OFTEN WILL THE RATES BE UPDATED?

A. The proposed formula rates will be calculated and filed by each July 1. The calculated rates will be applied to any ESAs entered into between July 1st and June 30th of the following year. The initial rate applied to the ESA will exist for the life of the ESA. In accordance with Section 5.02, the customer has the option to prepay the Excess Expenditure amount and then in lieu of the calculated charge for Special Facilities, pay an annual fixed charge for the recovery of operations and maintenance expenses related to the Excess Expenditure amount, billed in 12 equal monthly installments. The operations and maintenance expense rate is a subcomponent of the Special Facilities charge described herein.

VII. TARIFF CHANGES OTHER THAN RATES

Q. IS OTP PROPOSING ANY CHANGES TO ITS TARIFF SCHEDULES OTHER THAN THOSE RELATING TO RATES?

A. Yes. In its last rate case, OTP made several improvements and updates to its rate book. In this case, OTP is expanding on those improvements and is making additional changes, mainly to provide clarity of service conditions and requirements for customers and OTP. Many of the changes are common to all rate schedules, while others are specific to individual rate schedules. All of the changes are reflected in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4.

Q. IS OTP MAKING ANY SUBSTANTIVE CHANGES TO ITS TARIFFS THAT GO BEYOND CLARIFICATION?

A. Yes. The most major changes relate to new challenges OTP has experienced since the last rate case. There were several changes made to address the effect partial requirements customers have on OTP's system and the effect of adding new high-interconnection cost customers to the system. Changes to address these new challenges include changes to Contracts and Agreements, Special Facilities, Standby Service, and other more minor changes. In addition, there are other tariffs supported by other OTP witnesses in this case.

Q. WHY IS OTP MAKING CHANGES TO ITS TARIFFS TO ADDRESS PARTIAL REQUIREMENTS CUSTOMERS?

A. Since OTP's last rate case, we have seen an increasing interest in our service territory of customers interested in behind-the-meter generation, largely due to recently enacted federal incentives. When OTP commissioned its Standby Tariff in the early 1990's, it was designed to accommodate new customers being added to the system who might need standby services – such as back-up power, maintenance and supplemental power. It was not designed to deal with existing customers who move from full to partial requirements service. OTP's proposed revisions are designed to reflect current market conditions where customers are moving from full to partial requirements service. When full-requirements customers move from their current tariff to a standby tariff, different requirements are necessary to protect OTP's other customers from absorbing extra costs. The proposed changes also ensure that certain benefits that primary meter customers have, like combining multiple points of interconnection on one account with one meter charge, are not available to partial-requirements customers. Each change is summarized in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4, and the full redlined text is available in Volume 2C.

Q. WHY IS OTP MAKING CHANGES TO ADDRESS HIGH-INTERCONNECTION-COST CUSTOMERS?

A. Another change that we have seen since the last rate case is potential new customers interested in connecting to OTP's system that have unusually high interconnection costs. To protect other customers from having to subsidize these unusually high interconnection costs, OTP has updated its standard contracts and special facilities tariffs to provide more security for cost outlays OTP makes to connect customers.

Q. ARE THERE ANY OTHER CHANGES OF NOTE?

A. Yes. OTP is making a number of improvements to its general rules and regulations to add glossary definitions, clarify that certain tariffs are only available to qualifying customers, identifying with increased specificity rate qualifications, and other enhancements, in addition to the changes discussed above. These improvements are also included in Exhibit___(DGP-1), Schedule 4.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
A. Yes, it does.

Mr. David G. Prazak
Manager, Pricing & Rate Design
Regulatory Economics
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8595

CURRENT RESPONSIBILITIES (2012 – Present)

Manage the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates, rate design, and load research.

PREVIOUS POSITIONS

Otter Tail Power Company

2022-Present	Manager, Pricing & Rate Design
2019-2022	Supervisor, Pricing
2012-2019	Supervisor, Pricing & Tariff Administration
2000– 2012	Supervisor, Pricing
1997-2000	Senior Pricing Analyst

EPS Solutions

1990-1997	Associate I & II: Consultant in demand-side management planning, evaluation, and training

Northern States Power

1989-1990	Demand-Side Management (Intern): Aided in DSM activities

EDUCATION

Walden University	Masters of Public Administration, 2012
Minnesota State University, Moorhead	B.S., Energy Management, concentration in Industrial Technologies

Otter Tail Power Company

MARGINAL COST OF SERVICE STUDY

October 4, 2023

CRA Charles River Associates

Amparo Nieto
Principal

TABLE OF CONTENTS

1 INTRODUCTION

Charles River Associates was retained to prepare a Marginal Cost of Service Study (MCOS) on behalf of Otter Tail Power Company. This report summarizes the study approach to estimate OTP's overall marginal costs of service applicable during the period 2024 to 2028.

In electricity ratemaking, marginal costs are critical to design rates that incentivize economically efficient consumption patterns. A MCOS study informs the appropriate rate structure, differences in the hourly marginal cost associated with an additional kW of usage, appropriate time-of-use periods and price differentials across periods.

OTP's electricity marginal cost analysis required a review of the Midwest Independent System Operator (MISO)'s wholesale energy and capacity market rules and prices, expected near-term capacity conditions in the MISO region, transmission tariffs, Company's planned distribution substations and feeders, local connection costs, customer data.

2 TOU PERIODS

The costing Time of Use (TOU) periods used in this study were decided in consultation with the Company, upon review of hourly total marginal cost profiles for typical weekdays and weekends in each month. Table 1 below summarizes the new Time of Day (TOD) periods.

Table 1. OTP Time of Day and Seasonal Costing Periods

Summer: June – September	
Peak:	Monday - Friday, 1 pm - 7 pm
Shoulder	Monday - Friday, 11 am - 1 pm , 7 pm - 9 pm Weekends, 1 pm - 7 pm
Off-Peak	Monday - Friday, 9 pm to 11am Weekends, 7 pm - 1 pm
Winter: All other months	
Peak:	Monday - Friday, 7 am - 10 am
Shoulder:	Monday - Friday, 6 am - 7 am, 10 am - 9 pm
Off-Peak:	Monday - Friday, 9 pm - 6 am Weekends, all hours

In order for rates to provide efficient price signals to customers, the analysis of time periods must consider the prevailing conditions in the years when rates are expected to be in effect. The first step in our analysis was to compute all hourly marginal costs that change with time of day. These include generation, transmission and upstream primary distribution marginal costs. The analysis aims to group together hours with similar hourly marginal costs.

The TOU periods were defined for the seasons that the Company currently has in its existing rates. Modelling of hourly generation capacity cost involved a review of hourly net system loads in MISO during the prior 3 years and evaluating additions of solar and wind generation, expected during the upcoming 3 years (through 2026). Longer-term views will require reviewing the impact of future additions of renewable-based resources on MISO load profiles during the 2027-2030 timeframe, where cumulative wind, solar as well as storage capacity on-line will be expected to significantly increase in MISO and potentially shift peak period further into the evening, particularly for the summer months.[1] We recommend revisiting the TOU periods again at the next rate case. At that point, further granularity in seasons will be examined, given MISO's exposure to MISO seasonal construct. Decisions on TOU periods also evaluated probability of annual peak for every hour on the transmission and distribution systems.

3 MARGINAL GENERATION COSTS

3.1 Marginal Energy Costs

In a competitive electricity market, the marginal cost of generation is the market price of energy, as well as the market price of capacity if the change in demand occurs at a time of system peak demand. Estimating the hourly marginal generation capacity cost requires an estimate of annual capacity market prices in the MISO region, the target planning reserve margins by seasons, and cost allocation factors that are based on MISO's new reserve adequacy rules.

An increment of native load in any hour requires OTP to purchase more energy at the prevailing market prices or sell less to the market if OTP is a net seller in that hour. As a member of MISO's electricity wholesale market, OTP buys and sells on an hourly basis as needed to achieve the lowest cost of serving its retail customers. To update OTP's marginal energy costs, we relied on the latest forecast available of MISO's forward monthly peak and off-peak prices for the period January 2024 through December 2028. Forward market prices reflect MISO forward market energy prices for the Intercontinental Exchange (ICE), measured at the OTP node, based on historical hourly price differentials between the Indiana node and OTP's node. We converted the monthly energy peak and off-peak forward prices into hourly prices based on average variation in hourly day-ahead LMPs during the two-most recent years.

1 "Preliminary MTEP23 Review", September 12, 20023. About 31 GW of solar generation has been approved for interconnection in MISO, as well as 6 GW of wind, and 2 GW of energy storage, according to MISO's interconnection queue as of July 9 and approved projects. *Retrieved from Midcontinent Independent System Operator on September 14, 2023*

To convert market prices to energy marginal costs at customers' meters, market prices were adjusted for the financial cost of working capital required and marginal energy losses incurred from the OTP hub to customer meters. Section IX presents the resulting 2024-2028 marginal energy costs averaged by costing periods.

3.2 Marginal Generation Capacity Costs

MISO currently has a new seasonal resource adequacy capacity construct that replaced its single annual resource adequacy requirement with four seasonal resource adequacy requirements. The new seasons include summer, fall, winter and spring seasons, each with 3-month duration. To develop marginal capacity costs. OTP's marginal cost of generation capacity is triggered by changes in OTP's capacity obligation under MISO resource adequacy rules. The regional market capacity price represents OTP's opportunity costs when an OTP customer increases his usage at the time of MISO's seasonal coincident peak. MISO conducts a Loss of Load Expectation (LOLE) study that determines the required resources and Planning Reserve Margin (PRM) required to achieve the target LOLE level by season. MISO calculates seasonal PRMs calibrated to a LOLE is 1 day in 10 years.

OTP's marginal generation capacity cost in any hour on a planning basis is a function of the forecast seasonal capacity market price, which varies with the expected level of capacity surplus in MISO-wide region, the required PRM, which is applied to OTP's expected load coincident with the MISO seasonal peak, and the probability that each hour is MISO's system seasonal peak hour. This required a probability of peak analysis conducted for each of the four seasons defined under MISO seasonal construct. For the initial year of the timeframe, the seasonal capacity market prices reflect Zone 1 auction results from the 2023/2024 MISO capacity auction.

To estimate marginal generation capacity costs for the remaining period, the study uses a forecast of annual MISO capacity market prices developed by Wood McKenzie. Annual prices were apportioned to each of the four seasons based on MISO predictions of evolution of PRM and relative LOLE by season, which data published by MISO for the period 2023 - 2028.

We allocated the quarterly market capacity prices to each month within the season based on hourly probability of being the season's peak hour, using a profile of hourly MISO-net system peak loads in recent years In the final step, the monthly probabilities of peak were combined in order to obtain the market capacity price estimates according to the Company's preferred seasonality in its retail rates, i.e., two seasons, summer (June-Sep) and winter (Oct – May). Table 2 in Section 7 summarizes the marginal generation capacity cost averaged for the five-year planning period.

3.3 Marginal Transmission Costs

OTP operates in a joint pricing zone within the Midwest ISO. OTP's transmission system consists of 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Any transmission lines above 100 kV are under the functional control and planning of MISO and included as part of the Network Upgrade Charge (NUC). OTP has operational control of its transmission facilities at or below 100 kV. These facilities, plus those projects above 115 kV that are below $5 million, are considered by FERC in setting MISO Network Integration Transmission Service (NITS) rate for its Control Area. OTP's control area NITS rate also includes the transmission facilities of Great River Energy (GRE). Both the MISO NITS and NUC charges are constant every month, reflecting 1/12 of the applicable annual revenue requirement per kW.

Network Integration Transmission Service Rate

The NITS rate is recovered from each transmission user in the OTP Pricing Zone based on their monthly coincident peak loads. An increase in monthly coincident peak triggers an increase in MISO transmission bill, thus the NITS rate represents a financial marginal cost to OTP. Forecasting annual changes to OTP's NITS rate requires a review of OTP's transmission budgets for 115-kV below $5 million, 41.6 kV and 69 kV projects expected to come into service in the period 2022-2026, excluding projects that qualify for recovery through the transmission cost rider (TCR). We applied MISO's estimates of annual carrying charge to OTP's transmission investment to compute an annual incremental revenue requirement for the OTP Pricing Zone's NITS. Projections of 12 monthly OTP's control area CPs were used to estimate annual changes to OTP's NITS charge.

The forecasted monthly NITS rates for the period 2022-2026 were allocated to hours based on the probability that a given hour is the monthly peak on OTP's Control Area. The hourly transmission costs were adjusted by marginal losses and summarized by costing period. Section 7 provides the time-differentiated marginal transmission costs, averaged for 2024-2028 and stated both on a per-kWh and a per-kW basis.

Network Upgrade Charge

To estimate the second component of the financial transmission marginal cost, the NUC rate, we relied on MISO's calculation of projected annual revenue requirement as per Schedule 26. The cost of all new projects rated 345 kV and above with a project cost of $5M or greater is allocated through a hybrid method, so that 20% of the costs are allocated on a system-wide basis and the remaining 80% are allocated to planning sub-regions (West, Central and East) and pricing zones under a method that differs between economic and reliability projects. Costs of transmission projects rated below 345-kV, get allocated on a zonal basis based on each pricing zone's contribution to MISO's average 12 CPs.

To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2024 through 2028, MISO's NUC-related annual transmission revenue requirements allocated to OTP's pricing zone were divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate. The projected NUC charges were time-differentiated using the probability of peak analysis of OTP's control area.

Multi-Value Projects

In addition to the NITS and NUC charges, MISO included a transmission project rate category designated to recover the cost of Multi-Value Projects. These projects are driven by energy policy mandates and can address various reliability and/or economic issues, affecting multiple transmission zones. FERC determines, on an annual basis, a Multi-Value Project Usage Rate (MUR) on a per-MWh basis to recover these costs. OTP is required to pay these costs for every kWh of its native load and therefore it is a financial marginal cost component. The MCOS study calculates the MUR rate adjusted by energy losses at each voltage level of service.

Marginal Ancillary Service Costs

OTP must procure ancillary services in MISO markets to meet OTP's incremental net load in a given hour. The two types of ancillary services considered in the analysis are regulation and operating reserves (spinning and supplemental). The MCOS study relies on a forecast of average annual hourly cost stated in dollars per MWh, for each type of reserve estimated for year 2024-28. The expected average hourly cost was adjusted by marginal losses at each service voltage level and working capital, and time-differentiated using as a proxy hourly variation of energy market prices.

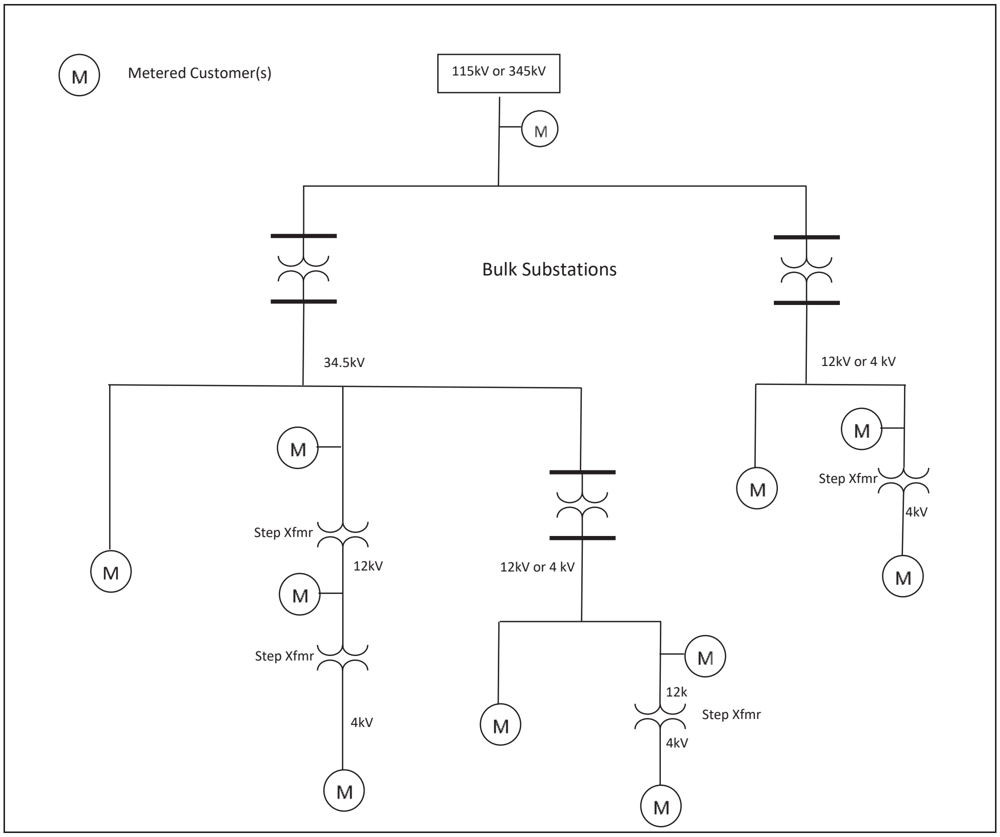
4 MARGINAL DISTRIBUTION COSTS

For purposes of estimating marginal costs of delivery, it is important to understand the configuration of the grid and determine what drives new investment. From this point of view, the costs of service can be grouped in four main categories:

1. Upstream distribution substations that are fed from the transmission system (115kV) and typically convert power to 34.5 kV.
2. Distribution substations that generally convert the power from 34.5 kV to 12 kV or directly 4 kV, and trunk-line primary feeders.
3. Local distribution facilities (line transformers, local primary taps, and secondary conductors)
4. Customer-related facilities and functions, including:
    a) Meters and service drops
    b) Customer-related services (*e.g.*, meter-reading, billing, accounting, customer information and customer service).

Figure 1 is a simplified diagram of OTP's electric distribution system.

Figure 1. OTP's Illustrative Electric Delivery System Diagram



4.1 Distribution Substation and Trunkline Feeder Costs

The distribution stations and trunkline feeders from the substation to the point where the line branches to create a primary tap line are expanded as the distribution area peak demands grow. Estimating the marginal cost of distribution substation and trunkline feeder cost per kW of demand required identifying the budgeted growth-related investments in OTP's most recent capital expansion plan. The sum of OTP's growth-related investment (stated in 2024 dollars) was divided by the estimated total growth in distribution substation non-coincident peak demands over the same period to obtain marginal investment per kW.

Distribution O&M expenses are a component of marginal distribution cost, since they grow with the amount of plant in service. OTP's annual distribution station O&M expenses during the period 2020-2022, stated in 2024 dollars, were divided by historical non-coincident peak demands across substations. After reviewing the trend in expenses per kW (in constant dollars), the four-year average of O&M expense per kW was considered a reasonable proxy for the marginal substation O&M expense.

To time differentiate the annualized distribution substation cost, the relative probability of distribution peak for months, day-types (weekdays, Saturday, and Sunday) were estimated based on historical hourly loads across OTP distribution substations. The analysis accounted for the relative lower carrying capability of this equipment in summer months as compared to the winter months. Peak demand loss factors were developed from OTP's 2020 loss study.

4.2 Local Distribution Facility Costs

The local distribution facilities, including secondary lines, line transformers, and local primary taps, are less extensively shared than the distribution substations. OTP engineers decide on the type of the required facilities using sizing standards that take into consideration the number of customers who are expected to use those facilities, their maximum loads over the service life of the facilities and other parameters such as the level of maximum transformer loading that can be expected to be safe. Thus, the marginal cost of local distribution facilities is strongly influenced by the connected customers' "design demands", i.e., the maximum long-term load that customers may impose on the transformer and conductor. Fluctuations of actual customer demand from month to month or even year to year are not expected to require a change in the installed facility.

Local distribution facility costs were estimated for residential, commercial and industrial customers and type of customer within each major rate class. The analysis used different connection scenarios. OTP provided transformer size and conductor costs from OTP's work order system, as well as an estimate of number of customers typically connected under each scenario. Marginal facilities costs were estimated as the monthly distribution cost per kW of customer's design demand. The design demands for various scenarios are affected by density (rural versus urban areas), whether it is a single customer vs. multi-unit building, and whether customers connected use all electric appliances instead of relying partially on gas. Design demand and cost of facilities also vary depending on whether the installation is underground or overhead, single-phase or three-phase.

To obtain an estimate of residential customer design demand, we reviewed the typical transformer sizes used for different types of customer connections and divided transformer capacity by the number of customers expected to be served, adjusted by a percentage of typical transformer utilization level provided by OTP to state the cost as a dollar per kW of long-term maximum demand as opposed to cost per required capacity. The streetlighting marginal distribution feeder cost was estimated on a per-fixture basis.

The marginal distribution facility O&M expenses were estimated using recent historical data, since a forecast of O&M expenses was not available. The average expense per kW of design demand averaged 2020 -2022 was used as the estimated future distribution facilities O&M expense going forward. The total design demand was the product of customer counts and per-customer average design demand estimates by rate.

5 MARGINAL CUSTOMER COSTS

5.1 Meter and Service Costs

OTP provided 2023 installed cost of a typical AMI meter, since OTP expects full deployment of smart meters over the next two years. The average per-meter O&M expense from recent years was used to represent the marginal level of these expenses. The MCOS study separately calculated meter requirements for small power producers, which vary with the specific rider and/or jurisdictional legislation. When a bi-directional and/or a generation meter are required for reporting purposes, there are incremental installed meter costs compared to the standard meter. The MCOS study includes a calculation of these incremental costs by DG rate category.

5.2 Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are a function of customers on the system. OTP's FERC Form 1 recent customer account and service expense levels were divided by class weighted customers to obtain an estimate of customer accounts expense per weighted customer. We estimated that the marginal customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal. Expenses associated with CIP and EEP, programs mandated by MN and SD to promote demand side measures, were omitted from the study since they are not marginal with respect to customer additions. Other non-marginal customer account and customer service and informational subaccounts were also excluded. The same procedure was used to allocate customer accounts expenses using the class weights developed for these expenses in embedded cost of service study. The average of 2020 through 2022 values was considered a reasonable proxy of the future marginal per-customer expense.

6 ANNUALIZED MARGINAL COSTS

The MCOS annualized marginal cost for each component of service by multiplying all marginal investment by an annual economic carrying charge, expressed as a percentage, and adjusting the investment per unit by the general plant loading factor and a plant-related A&G loading factor. To these costs, marginal O&M, adjusted by non-plant related A&G expenses, and revenue requirements for working capital, were added to obtain the total annualized marginal unit cost. A summary of the calculation of these components is provided below.

6.1 Loaders

Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. The MCOS estimated loading factors, in particular, plant-related A&G, non-plant-related A&G and general plant loading factors. Accounts not marginal with respect to other expenses or plant were excluded. The MCOS uses a non-plant-related A&G loader estimated based on the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 2012-2022.

For plant-related A&G, two A&G FERC accounts were identified to vary with the amount of plant in service: FERC Account 935 and FERC Account 924. Account 935 was regressed on cumulative net additions to total electric plant, all in constant dollars. Average property and terrorism insurance rate, which applies to distribution substations only, was used to estimate insurance loading factor. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. These may grow with electric plant expansion. The MCOS uses a General Plant loader based on a regression of cumulative net additions to general plant on cumulative net additions to total plant (less General plant). Since 1996 there has been very little change in OTP's general plant.

6.2 Economic Carrying Charges

To convert estimates of marginal distribution plant investment into annual costs requires estimating an economic carrying charge that reflects the elements of OTP's revenue requirement associated with incremental plant. Inputs to the economic carrying charge calculation include: the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), the expected inflation rate for that type of plant, net of technical progress, and the average service life and patterns of failure ("Iowa curve") for each type of plant.

OTP foresees financing of incremental investment through a combination of debt and sales of common stock (about 47 percent and 53 percent, respectively). The ECC calculation uses the average long-term incremental cost of debt and the long-term incremental cost of equity over the next ten years.

6.3 Working capital

The computation of working capital includes cash, materials, supplies and prepayments. The revenue requirement associated to working capital reflects OTP's weighted average cost of capital plus an income tax component that recognizes the taxable equity portion of the return on capital.

7 SUMMARY OF MARGINAL COSTS

7.1 Marginal costs time-differentiated by season and time of day

The time-differentiated marginal costs (including energy, generation capacity, transmission and distribution substation costs), in 2024$, were averaged over the 2024-2028 timeframe for each of the current periods in TOD rates. Tables 2 and 3 show the results on a per-kWh basis and on a per-kW basis, respectively.

Table 2. Summary of 2024-2028 Time-differentiated Marginal Costs ($ per-kWh)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2024 Cents per kWh)					
Secondary						
Energy	6.3262	5.1235	3.2859	5.6545	5.1415	4.4008
Generation Capacity	1.6417	0.5813	0.0219	0.2120	0.1725	0.0190
Op. Reserves	0.0929	0.0755	0.0485	0.0822	0.0750	0.0643
Transmission NITS/NUC	3.2249	0.6904	0.1036	3.5720	0.9346	0.2629
Transmission MUR	0.1698	0.1686	0.1677	0.1741	0.1726	0.1718
Distribution Substation	0.0340	0.0088	0.0001	3.5469	0.5129	0.1945
Total TOU	**11.4896**	**6.6481**	**3.6277**	**13.2417**	**7.0092**	**5.1132**
Primary						
Energy	6.1574	4.9961	3.2087	5.4679	4.9828	4.2706
Generation Capacity	1.5739	0.5575	0.0210	0.2010	0.1645	0.0181
Op. Reserves	0.0904	0.0734	0.0472	0.0799	0.0729	0.0625
Transmission NITS + NUC	3.0901	0.6618	0.0992	3.3531	0.8781	0.2467
Transmission MUR	0.1653	0.1670	0.1664	0.1711	0.1700	0.1694
Distribution Substation	0.0328	0.0085	0.0001	3.4254	0.4954	0.1879
Total TOU	**11.1099**	**6.4643**	**3.5426**	**12.6983**	**6.7636**	**4.9552**
Transmission						
Energy	6.0039	4.8798	3.1381	5.3006	4.8399	4.1532
Generation Capacity	1.4670	0.5199	0.0196	0.1841	0.1520	0.0167
Op. Reserves	0.0880	0.0715	0.0460	0.0776	0.0709	0.0608
Transmission NITS/NUC	2.8776	0.6166	0.0924	3.0256	0.7935	0.2225
Transmission MUR	0.1611	0.1605	0.1601	0.1632	0.1625	0.1621
Total	**10.5975**	**6.2483**	**3.4562**	**8.7512**	**6.0187**	**4.6154**

Table 3. Summary of 2024-2028 Time-Differentiated Marginal Capacity Costs ($ per-kW)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	($/kW-mo)					
Secondary						
Monthly Costs per kW						
Generation Capacity	$2.14	$0.91	$0.10	$0.14	$0.46	$0.08
Transmission	$4.21	$1.08	$0.46	$2.36	$2.47	$1.05
Distribution Substation	$0.04	$0.01	$0.00	$2.34	$1.35	$0.78
Total TOU MC	**$6.40**	**$2.01**	**$0.56**	**$4.84**	**$4.28**	**$1.90**
Monthly Average, seasonal	**$8.96**			**$11.02**		
Monthly Average, year-round	**$10.33**					
Primary						
Monthly Costs per kW						
Generation Capacity	$2.05	$0.88	$0.09	$0.13	$0.43	$0.07
Transmission	$4.03	$1.04	$0.44	$2.21	$2.32	$0.98
Distribution Substation	$0.04	$0.01	$0.00	$2.26	$1.31	$0.75
Total TOU MC	**$6.13**	**$1.93**	**$0.54**	**$4.61**	**$4.06**	**$1.81**
Monthly Average, seasonal	**$8.59**			**$10.47**		
Monthly Average, year-round	**$9.85**					
Transmission						
Monthly Costs per kW						
Generation Capacity	$1.91	$0.82	$0.09	$0.12	$0.40	$0.07
Transmission	$3.76	$0.97	$0.41	$2.00	$2.09	$0.89
Total TOU MC	**$5.67**	**$1.78**	**$0.50**	**$2.12**	**$2.50**	**$0.95**
Monthly Average, seasonal	**$7.95**			**$5.57**		
Monthly Average, year-round	**$6.36**					

7.2 Marginal Local Distribution Facilities Costs

Table 4 summarizes the monthly marginal local distribution facilities costs, stated as a fixed monthly cost per kW of customer's design demand (which may be the basis for a per-contract or customer-specific subscription demand). It is also stated as a fixed per customer cost by class, using the average customer design demand. Local distribution facilities cost in the fixed charge assumes that the average kW of transformer capacity required per customer is representative of the majority of the customers in the same class.

Table 4: Monthly Marginal Local Distribution Facilities Costs

Customer Class	Monthly Facility Cost per kW of Design Demand	Estimate of Typical Design Demand by Customer	Monthly Facility Cost per Customer
	($/kW)	kW	($/customer/mo.)
Residential			
Single Family Urban	$1.87	8.0	$14.93
Single Family Rural	$4.97	10.0	$49.75
Apartment Gas	$2.03	5.0	$10.13
Apartment Electric	$1.48	7.0	$10.33
Farm	$5.61	20.0	$112.19
Small Commercial			
Stand-Alone customer 1-ph, OH	$1.48	18.0	$26.64
Stand-Alone customer 3ph, OH	$1.48	45.0	$66.58
Shared-customer 3ph, OH	$1.39	25.0	$34.83
Stand-Alone customer 1ph, UG	$3.17	24.0	$76.07
Stand-Alone 3ph, UG	$3.10	45.0	$139.56
Large Commercial (Secondary)			
101-150kVa, 3ph	$1.45	125.0	$181.65
151-300kVa, 3ph	$1.14	230.0	$263.26
301-500kVa, 3ph	$0.92	400.0	$369.26
501-1000 kVa, 3ph	$0.75	775.0	$579.48
Large Commercial (Primary)			
101-500kVa, 3ph	$0.52	500.0	$262.40
501-1000 kVa, 3ph	$0.75	1,000.0	$747.72
Very Large Commercial (Secondary)			
1001-1500 kVa, 3ph	$0.72	1,250.0	$896.66
1501-2000 kVa, 3ph	$0.65	1,750.0	$1,132.08
Very Large Commercial (Primary)			
3000 kVa (LGS), 3ph	$0.53	2,500.0	$1,319.93
5000 kVa (LGS TOU), 3ph	$0.46	4,000.0	$1,821.72

7.3 Marginal Monthly Customer Costs

Table 5 summarizes the monthly marginal customer cost by customer class. Table 6 summarizes the monthly marginal cost for small power producers by rate class.

Table 5. Summary of Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost (2024 $/acc/mo.)
	Residential	
9.01	Residential Service	$17.07
9.02	Residential Demand Control	$21.37
9.04	Residential Service Time of Day	$18.60
14.01	Residential Water Heating Control Rider	$6.45
14.04	Residential Controlled Service - Large Dual Fuel Rider	$25.99
14.05	Residential Controlled Service - Small Dual Fuel Rider	$6.40
14.06	Residential Controlled Service - Deferred Load Rider	$9.10
14.07	Residential Fixed Time of Service Rider	$6.34
	Commercial and Industrial	
9.03	Farm Service	$21.71
10.01	Small General Service <20 kW	$24.19
10.02	General Service >= 20 kW	$54.23
10.03	General Service - Time of Use	$99.98
10.04	Large General Service (Secondary)	$113.62
	Large General Service (Primary)	$239.31
10.05	Large General Service - Time of Day (Secondary)	$108.29
	Large General Service - Time of Day (Primary)	$239.31
14.01	Commercial Water Heating Control Rider	$5.16
14.02	LGS - Real Time Pricing Rider (Secondary)	$86.97
	LGS - Real Time Pricing Rider (Primary)	$213.49
14.04	Commercial Controlled Service - Large Dual Fuel Rider	$33.41
14.05	Commercial Controlled Service - Small Dual Fuel Rider	$5.74
14.06	Commercial Controlled Service - Deferred Load	$16.76
14.07	Commercial Fixed Time of Service Rider	$16.76
	Miscellaneous	
11.05, 11.06	Other Public Authority	$33.45
11.02	Irrigation Service	$35.62
11.03	Outdoor Lighting	$3.59
11.03 11.04	Outdoor Lighting (unmetered)	$1.41

Table 6. Monthly Marginal *Incremental* Customer Cost of Small Power Producers by Rate Class

	Monthly *Incremental* Small PP Customer Cost (2024 $ /acc./mo.)
Residential Small Power Producer	
Residential	$0.87
Residential Demand Control	$0.99
Residential Water Heating Control Rider	$0.82
Residential Controlled Service - Deferred Load	$0.91
Commercial and Industrial Small Power Producer	
Small General Service <20 kW	2.21
General Service >= 20 kW	1.67
Farm Service	1.27
General Service - Time of Use	1.39
Large General Service (Secondary)	1.87
Large General Service (Primary)	1.07
Large General Service - Time of Day (Secondary)	1.12
Large General Service - Time of Day (Primary)	1.07
Commercial Controlled Service - Large Dual Fuel Rider	1.60
Commercial Controlled Service - Small Dual Fuel Rider	0.69
Miscellaneous	
Other Public Authority	1.38
Irrigation Service	1.50

Customers under the Small Power Producer Rider are responsible for the one-time marginal cost incurred by OTP when processing and energizing the interconnection. The MCOS estimated the cost of reviewing the application form filled out by the customer, performing a site inspection and interconnection study, and conducting a final site visit prior to the energizing of the generator. The resulting cost was adjusted for loaders and cash working capital. Table 7 reflects this calculation.

Table 7. One-Time Interconnection Expense per Small Power Producer

Small Power Producer Rider	Interconnection Labor Cost (2024$)
Average Annual Salary of Technical & Admin Personnel Involved	$115,245.40
Annual hours net of paid vacation & holiday	1,880.00
Hourly average labor cost	$61.30
Hours required per interconnection	$20.00
Expense per Interconnection Request	$1,226.01
With Non-Plant Related A&G	$1,275.18
Working Capital	
Cash Working Capital	85.05
Revenue Requirement for Working Capital	$7.55
Total One-time Incremental Cost to Process and Energize Interconnection	$1,282.73

APPENDIX A: DERIVATION OF ANNUALIZED MARGINAL COSTS

Tables A.1.1 through A.1.7 show the steps used in the derivation of the annualized marginal distribution substation and trunkline feeder costs, annualized marginal cost of local distribution facilities, and the annualized marginal customer-related costs.

Table A.1.1. Annualized Distribution Substation Costs

	2024 $/kW
Marginal Investment per kW	$336.45
With General Plant Loading	355.59
Annual Economic Carrying Charge Related to Capital Investment	8.10%
A&G Loading (plant related)	0.14%
Total Annual Carrying Charge	8.24%
Annualized Costs	29.30
O&M Expenses	3.10
With A&G	3.20
Subtotal	32.50
Material, Supplies and Prepayments	3.87
Cash Working Capital Allowance	0.21
Revenue Requirement for Working Capital	0.36
Total Distribution Substation Annual Cost	$32.86

Table A.1.2 Annualized Distribution Facilities Costs, Residential, Farm, Small Commercial

	Residential & Farm					Small Commercial				
	Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm	Stand-Alone customer 1-ph, OH	Stand-Alone customer 3ph, OH	Shared-customer 3ph, OH	Stand-Alone customer 1ph, UG	Stand-Alone 3ph, UG
Marginal Investment per kW of Design Demand	$223.00	$720.66	$248.51	$160.49	$822.24	$161.27	$161.16	$147.37	$431.67	420.77
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Annualized Costs	$16.49	$53.29	$18.38	$11.87	$60.80	$11.93	$11.92	$10.90	$31.92	$31.11
Annual O&M Expense per kW of Design Demand	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45
With A&G Loading x 1.0337	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
Subtotal Distribution Facilities Marginal Costs	$22.13	$58.93	$24.02	$17.51	$66.44	$17.56	$17.56	$16.54	$37.56	$36.75
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.23	$0.74	$0.25	$0.16	$0.84	$0.16	$0.16	$0.15	$0.44	$0.43
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr	**$22.39**	**$59.70**	**$24.30**	**$17.70**	**$67.31**	**$17.76**	**$17.75**	**$16.72**	**$38.03**	**$37.22**

Table A.1.3. Annualized Distribution Facilities Costs, Large Commercial

	Large Commercial (Secondary)				Large Commercial (Primary)		Very Large Commercial (Secondary TOU)		Very Large Commercial (Primary)	
	101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	501-1000 kVa, 3ph	101-500kVa, 3ph	501-1000 kVa, 3ph	1001-1500 kVa, 3ph	1501-2000 kVa, 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
Marginal Investment per kW of Design Demand	$156.95	$107.55	$72.10	$44.02	$8.34	$13.91	$39.16	$27.89	$38.06	$26.45
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Annualized Costs	$11.61	$7.95	$5.33	$3.26	$0.62	$1.03	$2.90	$2.06	$2.81	$1.96
Annual O&M Expense per kW of Design Demand	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$3.35	$3.35
With A&G Loading x 1.0337	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	3.46	3.46
Subtotal Distribution Facilities Marginal Costs	$17.24	$13.59	$10.97	$8.89	$6.26	$6.67	$8.53	$7.70	$6.28	$5.42
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.16	$0.11	$0.07	$0.05	$0.01	$0.01	$0.04	$0.03	$0.04	$0.03
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr)	**$17.44**	**$13.74**	**$11.08**	**$8.97**	**$6.30**	**$6.71**	**$8.61**	**$7.76**	**$6.34**	**$5.47**

Table A.1.4. Annualized Customer-Related Marginal Costs for Residential Customers

	Residential							
	Residential Service	Residential Demand Control	Residential Service Time of Day	Residential Water Heating Control	Residential Controlled Service - Large Dual	Residential Controlled Service - Small Dual	Residential Fixed Time of Service Rider	Residential Controlled Service - Deferred
nstalled Meter Cost	$126.79	$572.40	$275.44	$428.48	$2,038.37	$435.69	$437.51	$766.00
With General Plant Loading	$134.01	$604.97	$291.12	$452.86	$2,154.35	$460.48	$462.40	$809.58
Subtotal Annualized Meter Costs	$12.63	$57.01	$27.43	$42.67	$203.01	$43.39	$43.57	$76.29
With A&G Loading (Plant Related)	$12.65	$57.13	$27.49	$42.77	$203.44	$43.48	$43.67	$76.45
Meter O&M Expenses	$10.57	$16.91	$13.74	$10.57	$81.22	$10.57	$10.57	$10.57
Meter O&M with A&G loading	$10.93	$17.48	$14.20	$10.93	$83.96	$10.93	$10.93	$10.93
Sub-total Meter Installed Cost	**$23.58**	**$74.61**	**$41.70**	**$53.69**	**$287.41**	**$54.41**	**$54.59**	**$87.38**
nstalled Service Cost	$1,239.94	$1,239.94	$1,239.94	-	-	-	-	-
With General Plant Loading x 1.0569	$1,310.49	$1,310.49	$1,310.49	-	-	-	-	-
Annualized Service Drop Costs	$91.43	$91.43	$91.43	-	-	-	-	-
Subtotal Service with Plant-related A&G	**$91.69**	**$91.69**	**$91.69**	-	-	-	-	-
ustomer services								
Customer Accounts Expenses	$75.33	$75.33	$75.33	$22.25	$21.02	$21.02	$20.19	$20.19
Customer Service & Informational Expenses	$9.44	$9.44	$9.44	$0.02	$0.06	$0.06	$0.03	$0.03
Sub-total Cust. Expenses with A&G Loading	**$87.63**	**$87.63**	**$87.63**	**$23.02**	**$21.79**	**$21.79**	**$20.90**	**$20.90**
Working Capital Rev. Req.								
Material, Supplies and Prepayments	$1.40	$1.85	$1.55	$0.44	$2.08	$0.45	$0.45	$0.78
Cash Working Capital	$0.58	$0.62	$0.60	$0.20	$0.61	$0.19	$0.19	$0.19
Total Annual Marginal Customer Costs ($ /account/yr)	**$204.88**	**$256.40**	**$223.16**	**$77.35**	**$311.89**	**$76.84**	**$76.13**	**$109.25**

Table A.1.5. Annualized Customer-Related Marginal Costs for Commercial Customers

	General Service			Farm	Large General Service	
	Small General Service <20 kW	General Service >= 20 kW	General Service - Time of Use	Farm Service	Large General Service (Secondary)	Large General Service (Primary)
Installed Meter Cost	$390.43	$2,136.46	$1,700.25	$633.55	$2,378.96	$6,037.96
With General Plant Loading	$412.64	$2,258.02	$1,797.00	$669.60	$2,514.32	$6,381.52
Subtotal Annualized Meter Costs	$38.89	$212.78	$169.34	$63.10	$236.93	$601.35
With A&G Loading (Plant Related)	$38.97	$213.23	$169.70	$63.23	$237.44	$602.63
Meter O&M Expenses	$16.91	$129.96	$259.92	$16.91	$259.92	$1,299.59
Meter O&M with A&G loading	$17.48	$134.34	$268.68	$17.48	$268.68	$1,343.39
Sub-total Meter Installed Cost	**$56.45**	**$347.57**	**$438.37**	**$80.72**	**$506.11**	**$1,946.02**
Installed Service Cost	$1,505.34	$2,397.10	$2,397.10	$1,437.95	$3,352.78	$4,132.21
With General Plant Loading x 1.0569	$1,590.99	$2,533.50	$2,533.50	$1,519.77	$3,543.55	$4,367.33
Annualized Service Drop Costs	$111.00	$176.75	$176.75	$106.03	$247.22	$304.69
Subtotal Service with Plant-related A&G	**$111.31**	**$177.26**	**$177.26**	**$106.33**	**$247.93**	**$305.56**
Customer services						
Customer Accounts Expenses	$107.02	$107.02	$107.02	$60.11	$129.76	$129.76
Customer Service & Informational Expenses	$8.89	$8.89	$449.21	$8.47	$449.21	$449.21
Sub-total Cust. Expenses with A&G Loading	**$119.82**	**$119.82**	**$574.97**	**$70.89**	**$598.48**	**$598.48**
Working Capital Rev. Req.						
Material, Supplies and Prepayments	$1.94	$4.63	$4.19	$2.12	$5.86	$10.40
Cash Working Capital	$0.81	$1.48	$4.95	$0.52	$5.08	$11.24
Total Annual Marginal Customer Costs ($ /account/yr)	**$290.33**	**$650.76**	**$1,199.74**	**$260.58**	**$1,363.46**	**$2,871.70**

Table A.1.6. Annualized Customer-Related Marginal Costs Large Commercial Customers

	Large General Service				Commercial Riders				
	LGS - Real Time Pricing Rider (Secondary)	LGS - Real Time Pricing Rider (Primary)	Large General Service - Time of Day (Secondary)	Large General Service - Time of Day	Commercial Water Heating Control Rider	Commercial Controlled Service - Large Dual	Commercial Controlled Service - Small Dual	Commercial Controlled Service - Deferred	Commercial Fixed Time of Service Rider
nstalled Meter Cost	$1,700.25	$6,037.96	$1,700.25	$6,037.96	$275.44	$2,419.04	$290.78	$437.51	$437.51
With General Plant Loading	$1,797.00	$6,381.52	$1,797.00	$6,381.52	$291.12	$2,556.69	$307.32	$462.40	$462.40
Subtotal Annualized Meter Costs	$169.34	$601.35	$169.34	$601.35	$27.43	$240.93	$28.96	$43.57	$43.57
With A&G Loading (Plant Related)	$169.70	$602.63	$169.70	$602.63	$27.49	$241.44	$29.02	$43.67	$43.67
Meter O&M Expenses	$259.92	$1,299.59	$259.92	$1,299.59	$10.57	$129.96	$16.91	$129.96	$129.96
Meter O&M with A&G loading	$268.68	$1,343.39	$268.68	$1,343.39	$10.93	$134.34	$17.48	$134.34	$134.34
Sub-total Meter Installed Cost	**$438.37**	**$1,946.02**	**$438.37**	**$1,946.02**	**$38.42**	**$375.78**	**$46.50**	**$178.01**	**$178.01**
nstalled Service Cost	-	-	$3,412.60	$4,132.21	-	-	-	-	-
With General Plant Loading x 1.0569	-	-	$3,606.77	$4,367.33	-	-	-	-	-
Annualized Service Drop Costs	-	-	$251.63	$304.69	-	-	-	-	-
Subtotal Service with Plant-related A&G	**-**	**-**	**$252.35**	**$305.56**	**-**	**-**	**-**	**-**	**-**
ustomer services									
Customer Accounts Expenses	$129.76	$129.76	$129.76	$129.76	$22.25	$21.02	$21.02	$21.02	$21.02
Customer Service & Informational Expenses	$449.21	$449.21	$449.21	$449.21	$0.02	$0.06	$0.06	$0.03	$0.03
Sub-total Cust. Expenses with A&G Loading	**$598.48**	**$598.48**	**$598.48**	**$598.48**	**$23.02**	**$21.79**	**$21.79**	**$21.76**	**$21.76**
Working Capital Rev. Req.									
Material, Supplies and Prepayments	$1.74	$6.17	$5.23	$10.40	$0.28	$2.47	$0.30	$0.45	$0.45
Cash Working Capital	$5.08	$11.24	$5.08	$11.24	$0.20	$0.90	$0.23	$0.90	$0.90
Total Annual Marginal Customer Costs	**$1,043.68**	**$2,561.92**	**$1,299.52**	**$2,871.70**	**$61.92**	**$400.94**	**$68.82**	**$201.11**	**$201.11**

Table A.1.6. Annualized Customer-Related Marginal Costs - Irrigation and Lighting

	Other Rates			
	Irrigation Service	Other Public Authority	Outdoor Lighting	Outdoor Lighting (unmetered)
Installed Meter Cost	$1,379.30	$584.01	$275.44	-
With General Plant Loading	$1,457.78	$617.24	$291.12	-
Subtotal Annualized Meter Costs	$137.37	$58.16	$27.43	-
With A&G Loading (Plant Related)	$137.66	$58.29	$27.49	-
Meter O&M Expenses	$81.22	$129.96	$0.00	-
				-
Meter O&M with A&G loading	$83.96	$134.34	$0.00	-
Sub-total Meter Installed Cost	**$221.63**	**$192.63**	**$27.49**	-
Installed Service Cost	$1,420.82	$1,605.91	$124.11	$145.47
With General Plant Loading x 1.0569	$1,501.67	$1,697.29	131.17	$153.74
Annualized Service Drop Costs	$104.76	$118.41	9.15	$10.73
Subtotal Service with Plant-related A&G	**$105.06**	**$118.75**	**9.18**	**$10.76**
Customer services				
Customer Accounts Expenses	$84.01	$74.95	$4.71	$4.71
Customer Service & Informational Expenses	$9.70	$8.73	$1.02	$1.02
Sub-total Cust. Expenses with A&G Loading	**$96.87**	**$86.50**	**$5.92**	**$5.92**
Working Capital Rev. Req.				
Material, Supplies and Prepayments	$2.86	$2.24	$0.41	$0.15
Cash Working Capital	$1.05	$1.28	$0.04	$0.04
Total Annual Marginal Customer Costs ($ /account/yr)	**$427.47**	**$401.40**	**$43.04**	**$16.86**

Test Year 2024 Operating Revenue Summary Comparison with Marginal Cost Revenue - By Rate Schedule

Line No.	CCOSS or EPMC Method	Rate Schedule	Operating Revenues: Present	Operating Revenues: Proposed	Difference	Change in Base Revenues	2024 Average Revenue 100% Marginal Cost	2024 Proposed Revenue as % of 100% MC	Marginal Revenue Allocation
1	Class Level Increase	9.01 Residential Service (Rate 101)	$ 32,153,465	$ 44,251,924	$ 12,098,459	37.63%	$ 43,489,167	101.75%	85.9%
2		9.02 Residential Demand Control (Rate 241)	$ 4,780,572	$ 6,672,708	$ 1,892,136	39.58%	$ 7,127,595	93.62%	14.1%
3		**Total Residential:**	**$ 36,934,037**	**$ 50,924,632**	**$ 13,990,595**	**37.88%**	**$ 50,616,763**	**100.61%**	**100.0%**
4									
5	Class Level Increase	9.03 Farm Service (Rate 361)	$ 1,830,773	$ 2,565,269	$ 734,495	40.12%	$ 3,168,715	80.96%	100.0%
6		**Total Farm:**	**$ 1,830,773**	**$ 2,565,269**	**$ 734,495**	**40.12%**	**$ 3,168,715**	**80.96%**	**100.0%**
7									
8	EPMC Method 1	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 7,779,957	$ 11,454,106	$ 3,674,148	47.23%			
9		10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 1,645	$ 1,882	$ 237	14.41%			
10		**10.01 Small General Service - Under 20 kW**	**$ 7,781,602**	**$ 11,455,988**	**$ 3,674,385**	**47.22%**	**$ 11,383,603**	**100.64%**	**31.8%**
11		10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 19,521,819	$ 26,524,434	$ 7,002,615	35.87%			
12		10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 57,141	$ 68,314	$ 11,173	19.55%			
13		**10.02 General Service - 20 kW or Greater**	**$ 19,578,959**	**$ 26,592,748**	**$ 7,013,789**	**35.82%**	**$ 24,440,389**	**108.81%**	**68.2%**
14		**10.03 General Service - Time of Use** (Commercial TOU) - (Rates 708, 709, 710)	$ 6,204	$ 8,457	$ 2,253	36.32%	**$ 7,802**	**108.39%**	**0.022%**
15		**Total General Service:**	**$ 27,366,763**	**$ 38,057,193**	**$ 10,690,430**	**39.06%**	**$ 35,831,795**	**106.21%**	**100.0%**
16	**[PROTECTED DATA BEGINS...**								
17									
18									
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23									
24									
25									**...PROTECTED DATA ENDS]**
26	EPMC Method 1	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)	$ 24,947	$ 33,293	$ 8,346	33.46%	$ 33,463	99.49%	37.22%
27		11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)	$ 29,198	$ 46,646	$ 17,448	59.76%	$ 56,439	82.65%	62.78%
28		Total Irrigation:	**$ 54,144**	**$ 79,939**	**$ 25,794**	**47.64%**	**$ 89,902**	**88.92%**	**100.0%**
29									
30	Class Level Increase	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)	$ 95,933	$ 98,440	$ 2,507	2.61%			
31		11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)	$ 97,067	$ 99,591	$ 2,524	2.60%			
32		11.03 Outdoor Lighting - Signal (Rate 744)	$ 41,803	$ 42,890	$ 1,087	2.60%			
33		11.04 Outdoor Lighting - Street & Area Lighting (Rate 741, 743)	$ 900,453	$ 950,046	$ 49,593	5.51%			
34		11.07 LED STREET and AREA LIGHTING – DUSK TO DAWN (Rate 730, 731)	$ 1,558,539	$ 1,572,920	$ 14,382	0.92%			
35		Total Lighting:	**$ 2,693,795**	**$ 2,763,887**	**$ 70,092**	**2.60%**	N/A	N/A	N/A
36									
37	Class Level Increase	11.05 Municipal Pumping - Secondary Service (Rate 872)	$ 818,301	$ 1,207,388	$ 389,087	47.55%	$ 1,494,535	80.79%	100.00%
38		11.06 Civil Defense - Fire Sirens (Rate 843)	$ 2,553	$ 3,755	$ 1,202	47.09%	N/A	N/A	N/A
39		Total Other Public Authority:	**$ 820,854**	**$ 1,211,143**	**$ 390,289**	**47.55%**	**$ 1,494,535**	**81.04%**	**100.0%**
40									
41	Class Level Increase	14.01 Water Heating - Controlled Service (Rate 191)	$ 688,841	$ 884,120	$ 195,279	28.35%	$ 2,572,417	34.37%	66.54%
42		14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	$ 601,122	$ 771,533	$ 170,411	28.35%	$ 1,293,615	59.64%	33.46%
43		Total Water Heating:	**$ 1,289,964**	**$ 1,655,653**	**$ 365,690**	**28.35%**	**$ 3,866,034**	**42.83%**	**100.0%**
44									
45	EPMC	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	$ 1,154,187	$ 2,067,283	$ 913,096	79.11%	$ 2,100,128	98.44%	37.73%
46		14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	$ 2,851,749	$ 3,412,273	$ 560,524	19.66%	$ 3,466,488	98.44%	62.27%
47		Total Interruptible:	**$ 4,005,936**	**$ 5,479,556**	**$ 1,473,620**	**36.79%**	**$ 5,566,617**	**98.44%**	**100.0%**
48									
49	Class Level Increase	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	$ 164,901	$ 211,104	$ 46,203	28.02%			
50		14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	$ 114,268	$ 142,110	$ 27,842	24.37%			
51		Total Deferred Load:	**$ 279,169**	**$ 353,213**	**$ 74,045**	**26.52%**	**$ 647,720**	**54.53%**	**100.0%**
52									
53		TOTAL REVENUE:	$ 113,381,480	$ 154,957,208	$ 41,575,728	36.67%	$ 140,459,541	110.32%	

Section No.	Section description	Changes
All sections	General Rules and Regulations and Electric Rate Schedules	• Spacing adjustments were made where appropriate. No symbol was added to the change code column of the rate schedule to signify these changes. Due to the nature of these changes, they will not appear in redline. • Various changes were made throughout to correct capitalization and various typos. These changes do appear in redline but may not be called out in this Schedule 3.
All sections	General Rules and Regulations and Electric Rate Schedules	• In the Header o On all pages increased revision number by one. • In the Footer o Deleted the date located after the words “Approved by order dated”. o Replaced the number located after the words “Case No.” with PU-23-. • Deleted the effective date following the words “EFFECTIVE with bills rendered on and after”
Index	Index	• Updated several Rate Schedule titles to be consistent with our Matrices. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Added the NEW Section 13.12 Interim Rate Rider. • Added the NEW Section 13.13 Sales Rider. • Updated the Section 14.04 title with the new combined 14.04 and 14.05 title. • Deleted the Section 14.05 Controlled Service – Interruptible Load Self Contained Metering Rider and changed it to Reserved for Future Use.
1.02	Application for Service	• The word “becoming” has been added to paragraph one for clarification.
1.05	Contracts and Agreements	• Updated the following contracts and agreements: • Electric Service Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 3: Added language to refer to Excess Expenditures rather than additional costs for clarity. o Paragraph 4: Added language to specify that all mandatory riders apply, as well as voluntary riders

Section No.	Section description	Changes
		the customer chooses to participate in. o Paragraph 5: added language reserving the Company's right to temporarily suspend the delivery of power if necessary to protect public safety. o Paragraph 6: added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Paragraph 7 clarified language regarding the purpose of minimum payments for service extension costs. • Irrigation Electric Service Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 4: Added language to specify that all mandatory riders apply, as well as voluntary riders the customer chooses to participate in. o Paragraph 6: Added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Paragraph 7: Removed unnecessary words for clarity. o Paragraph 8: Added language to clarify payments for costs includes Special Facilities charges, identifying the dollar amount of the Company's investment, and updating the two options for payment of the annual fixed charge, changing the first method of calculating the annual fixed charge from 18% of the Company's investment, to the rate in effect at the time the ESA is signed multiplied by the annual amount of the Company's investment paid in seven equal monthly payments, and changing the second method of calculating the annual fixed charge from 3.5% of the Company's investment after prepayment of certain costs, to the rate in effect at the time the ESA is signed multiplied by the annual amount of the Company's

Section No.	Section description	Changes
		investment after prepayment of certain costs, paid in seven equal monthly payments. o Paragraph 9: Deletes the entire paragraph requiring minimum payments. • Outdoor Lighting and Municipal Services Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 2: Limits the length of the term of the contract to one year, and added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Unnumbered paragraph was designated as paragraph 3, and all subsequent paragraphs were advanced by one number. o Paragraph 14 (now 15): Added language to refer to Excess Expenditures rather than additional costs for clarity. • Summary Billing Service Contract: o Customer Authorization: Language was added to clarify that Rules and Regulations may be updated and updates will apply, language was added to notify customers that they can obtain a copy of the Rules and Regulations from the Company, language was added to require accounts to be included be attached to the contract, and language was added to provide for customer either completing a Summary Billing Service Worksheet or most recent copy of all bills. Removes language limiting liability. o Changes by Customer: Reworded to be clearer. o Changes by Company: Removes redundant sentence. o Cancellation (now Termination): Replaces cancellation with termination. o Adds new section titled Liability: Adds language limiting liability that used to be in the Customer Authorization section and relocates them to the new Liability section.

Section No.	**Section description**	**Changes**
2.02	Service Classification	• The first paragraph has been updated to clarify that rates designated "General Service" are available to any nonresidential Customer who meets the qualification for the rate. • Two lines at the bottom of page 1 were moved to page 2.
4.14	Combined Metering	• Language has been added to clearly state that to qualify for Combined Metering a Customer must take full requirements service from the Company.
5.01	Extension Rules and Minimum Revenue Guarantee	• Language has been updated in the first paragraph for clarity and an easier read. • Language was added to clarify that if the Company has reason to question whether a customer will cease to take full requirements from the Company, the Company may require the Customer to pay in advance or require any additional conditions of service that are reasonably necessary to protect the Company and its customers.
5.02	Special Facilities	• The tariff is being included in its entirety due to material within the tariff being relocated to other pages. • New language has been inserted on page 2 describing that the charge for Special Facilities will be computed from a formula rate template using inputs from FERC Form 1 with the following expense components; operation and maintenance expense, general and common depreciation expense, taxes other than income tax and distribution depreciation expense. The return component will contain income taxes and return on rate base. • Additionally, on page 2 the following was added: The charge for Special Facilities will be calculated annually and applied to any Electric Service Agreement (ESA) entered into while that rate is in effect and applicable for the life of the ESA. This section will apply unless the company and customer have expressly agreed to different charges in an ESA approved by the Commission. • In the Excess Expenditures section on page 2 "and Operation" was added for clarification. • Expenditure has been changed to Expenditure**s** on page 2 for accuracy. • Capitalized Meter on the last page because it is a term within our Glossary. • Added two new paragraphs on page 5 in the Special Facilities Payments section as follows: Payments required will be made on a non-refundable basis and may be required in advance of construction

Section No.	Section description	Changes
		unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a requesting party shall not change the Company's ownership interest or rights. Charges for Special Facilities shall be an annual fixed charge of the costs associated with the Excess Expenditures, billed in 12 equal monthly installments, unless another period is specified in the applicable rate schedule or Commission-approved ESA.
8.01	Glossary	• Included the following new Glossary Terms: Account, Full-requirement Customer, Government Unit, Megawatt (MW), Meter Multiplier, Non-Standby Service Customer, Partial-requirements Customer, Seasonal Customer, Single-phase, Standby Service Customer, Tariff (Tariff Schedules), and Three-phase. • Capitalized several terms because they are Glossary Terms. • Due to these changes, material within the tariff has been relocated to other pages.
9.01	Residential Service	• Updated the Rate Box to include a Facilities Charge per Month • Capitalized Residential and Customer because they are Glossary Terms. • Updated the rates. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
9.02	Residential Demand Control Service (RDC)	• Updated the Rate Box to include a Facilities Charge per Month • Capitalized Winter because it is a Glossary Term. • Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE:** An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
9.03	Farm Service	• Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates.

Section No.	Section description	Changes
		• Added a new page 2 to this tariff. • Inserted a new paragraph on page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE:** An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
10.01	Small General Service (Under 20 kW)	• Updated the Rate Box to include a Facilities Charge per Month • Updated the rates. • Capitalized Demand on page 2 because it is a Glossary Term. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer's design (rather than metered) Demand.
10.02	General Service (20 kW or Greater)	• Updated the title to include "20 kW or greater and less than 200 kW". • Updated the Rate Code box at the top of page 1 closing our current General Service Rates to New Customers and adding new General Service Rate Codes for customers going forward on these rates with the new Terms and Conditions included on page 2. • Updated the Application of Schedule section on page 1 with a 200 kW limit. • Updated the Rate Box to include a Demand Charge per kW (minimum 20 kW) charge. • Updated the rates. • Added additional language to the Terms and Conditions as follows: The Customer may remain on this schedule as long as the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.

<table>
<tr><th>Section No.</th><th>Section description</th><th>Changes</th></tr>
<tr><td>10.03</td><td>General Service - Time of Use</td><td>
Updated the title to include “20 kW or greater and less than 200 kW”.
Updated the Rate Code box at the top of page 1 closing our current General Service – Time of Use Rates to New Customers and adding new General Service – Time of Use Rate Codes for customers going forward on these rates with the new Terms and Conditions included on page 2.
Updated the Application of Schedule section on page 1 with a 200 kW limit.
Updated the rates.
Added additional language to the Terms and Conditions as follows: The Customer may remain on this schedule as long as the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.
Updated the definition of Declared, Intermediate and Off-Peak periods by season.
</td></tr>
<tr><td>10.04</td><td>Large General Service</td><td>
Updated the Application of Schedule section on page 1 to direct our customers to the details in our Terms and Conditions.
Updated the Rate Box to clarify that the demand charge is per month.
Updated the rates.
Added a new Terms and Conditions section on page 3 as follows.
A Customer with a Billing Demand of greater than 200 kW for 12 consecutive months will be required to take service under the Large General Service (Section 10.04) or Large General Service schedule – Time of Day (Section 10.05).
The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or

</td></tr>
</table>

Section No.	Section description	Changes
		10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.
10.05	Large General Service - Time of Day	• Added a new page 5 to this tariff. • Updated the Application of Schedule section on page 1 to direct our customers to the details in our Terms and Conditions. • Changed the term Shoulder to Mid-Peak throughout the entire tariff. • Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates. • Added a new Terms and Conditions section on page 3 as follows: o A Customer with a Billing Demand of greater than 200 kW for 12 consecutive months will be required to take service under the Large General Service schedule (Section 10.04) or Large General Service schedule – Time of Day (Section 10.05). o The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or 10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule. • Updated the definitions of On-Peak, Mid-Peak and Off-peak periods by season. • Added a NEW Optional Trial Service at the bottom of page 4 continuing onto the new page 5 as follows: o Customers may elect Time of Day service for a trial period of three months. o If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment. o If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of

Section No.	**Section description**	**Changes**
		one year as described in the General Rules and Regulations Section 1.02. o The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.
11.01	Standby Service	• Added a new page 9 to this tariff. • Updated the rates. • Changed the term Shoulder to Mid-Peak throughout the entire tariff. • Added Supplemental Demand Summer and Winter Rates for both Option A – Firm Standby and Option B – Non-Firm Standby. • Added definitions for Determination of Billing Demand and Adjustment for Excess Reactive Demand on page 5 as follows: **DETERMINATION OF BILLING DEMAND:** The Billing Demand shall be the Metered Demand adjusted for Excess Reactive Demand. **ADJUSTMENT FOR EXCESS REACTIVE DEMAND**: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of measured Reactive Demand in excess of 50% of the Metered Demand in kW. • Updated the Backup Service hours at number 2 of the Terms and Conditions on page 5. • Capitalized Season on page 5 and Distribution on page 7 because they are Glossary terms. • Corrected the spelling of manages in the MISO definition on page 7. • In the Definitions and Useful Terms section on page 7, Contracted Backup Demand has been updated to include the following: The Contract Backup Demand is set by mutual agreement of the Customer and Company to electric capacity levels sufficient to meet the customer's standby load. If the Company determines the capacity levels sufficient for the customers' standby load have changed, within two billing cycles, the Contracted Backup Demand will require review by both Company and Customer, for both billing and resource planning purposes. Any billing adjustments will be retroactive to the month the Company notified the Customer.

Section No.	Section description	Changes
		• In the Definitions and Useful Terms section on page 8, the following language was **removed** from Non-Standby Service Customer section: For Large General Service or Large General Service – Time of Use Customers, a Special Minimum Demand may apply. • In the Definitions and Useful Terms section on page 9, the following Special Minimum Demand definition was **removed**: Special Minimum Demand is a special Demand calculation that the Company may use at its option for the Large General Service or Large General Service – Time of Day Customers. The terms are outlined in Sections 10.04 and 10.05. • In the Definitions and Useful Terms section on page 9, non-Company was changed to Customer in the Standby Service Customer term. • In the Definitions and Useful Terms Section on page 9, in the Supplemental Service term, the following language was **removed**: Except for determination of Demand, Supplemental Service shall be provided under Standard Rate Schedule 10.05. • Updated the definitions of On-Peak, Mid-Peak and Off-Peak periods by seasons.
11.02	Irrigation Service	• Updated the rates. • Clarified in the Rate Boxes to see the Facilities Charge section of the tariff for details. • Updated the Facilities Charge section on page 2 to reference Section 5.02, Special Facilities, for the annual fixed charge. • Updated the definitions of Declared, Intermediate and Off-Peak periods by seasons.
11.03	Outdoor Lighting - Energy Only - Dusk to Dawn	*Rate changes only*
11.04	Outdoor Lighting - Dusk to Dawn (CLOSED TO NEW INSTALLATIONS)	• Updated the rates. • Capitalized Energy on page 3 because it is a Glossary term. • Removed "Interim" from the header on page 3.
11.05	Municipal Pumping Service	*Rate changes only*
11.06	Civil Defense - Fire Sirens	• Updated the rates. • Capitalized Distribution Facilities and Distribution because they are Glossary terms.

Section No.	**Section description**	**Changes**
11.07	LED Street and Area Light - Dusk to Dawn	• Updated the rates. • Capitalized Customer on page 1 because it is a Glossary term.
12.00	**Purchase Power Riders - Applicability Matrix**	• Updated the title for consistency in our Rate Books with other jurisdictions. • Updated Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW)
12.01	Small Power Producer Rider Occasional Delivery Energy Service	*No changes – Not included in this filing*
12.02	Small Power Producer Rider Time of Delivery Energy Service	*No changes – Not included in this filing*
12.03	Small Power Producer Rider Dependable Service	*No changes – Not included in this filing*
13.00	**Mandatory Riders – Availability Matrix**	• Correction to the title including in the headers. • Added a new page 3 to this tariff. • Updated several Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Added our NEW Interim Rate Rider. • Added our NEW Sales Rider. • Updated rows for Section 14.04 and 14.05 to show them combined as Section 14.04. Section 14.05 is now Reserved for Future Use. • A third page was added to increase the size of our tables for easier reading. The Mandatory Riders remain on page 2 and the Voluntary Riders have been moved to a new page 3. Headings were added to the moved Voluntary Riders table on page 3. • Various changes have been made to the applicability indicators for these Mandatory Riders. Following a thorough review, it was determined these updates were necessary.

Section No.	Section description	Changes
		Civil Defense – Fire Sirens: Applies if the Rider is a Percent of Bill. *Water Heating Control Rider*: Due to the Credit on this rider these were changed to "May Apply". *Section 14.05* – Are being removed because this tariff is now Reserved for Future Use. *Economic Development Rate Rider:* These do not apply due to this being a discount.
13.01	Energy Adjustment Rider	• The title has been updated to indicate that this rider is identified on the bill as Fuel & Purchase Power. • Capitalized Kilowatt and Kilowatt-hour on page 1 because they are Glossary terms. • The Energy Adjustment Factor service categories on page 1 have been updated to properly describe our Controlled Service categories. • Section 14.05 has been removed from the Controlled Service Interruptible service category because it has been combined with Section 14.04. • Section 14.06 has been moved to the newly titled Controlled Service Deferred Load category. • MISO on page 2 has been correctly identified as Midcontinent Independent System Operator. • At number 8 on page 2 the narrative has been updated to state as follows: All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall be included in the Energy adjustment calculation described in this schedule. • The following statement was added to the Asset-based Sales Margin description at the top of page 3: One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred. • On page 3, how the amount of the Asset-based Sales Margin credit was previously determined has been removed from this tariff. • A new number 9 has been inserted on page 3 as follows: 9. The costs of fuel and reagents resulting from steam and water sales and the revenues from steam and water sales shall be included in the energy adjustment rider. • Our standard Mandatory and Voluntary Riders paragraph directing customers to our matrices at Section 12.00, 13.00 and 14.00 has been added to this tariff as follows: **MANDATORY AND VOLUNTARY RIDERS:** The

Section No.	Section description	Changes
		amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.
13.02	Reserved for Future Use	*No changes – Not included in this filing*
13.03	Reserved for Future Use	*No changes – Not included in this filing*
13.04	Renewable Resource Cost Recovery Rider	*No changes – Not included in this filing*
13.05	Transmission Cost Recovery Rider	• The Application of Rider section on page 1 has been updated to include a reference to our matrices. • The Rate Box has been updated to include Section 11.01, Standby Service, in our Large General Service group (a) and in the Controlled Service group (b) a change has been made to show the combining of Sections 14.04 and 14.05.
13.06	Generation Cost Recovery Rider	• The Application of Rider section on page 1 has been updated to include a reference to our matrices. • Capitalized Customer's because it is a Glossary term. • Updated the rate to zero. • Page 2 is being included to correct an indention issue within the Forecasted retail revenues paragraph near the middle of the page.
13.07	Reserved for Future Use	*No changes – Not included in this filing*
13.08	Environmental Cost Recovery Rider	*No changes – Not included in this filing*
13.09	Reserved for Future Use	*No changes – Not included in this filing*
13.10	Reserved for Future Use	*No changes – Not included in this filing*
13.11	Advanced Meter and Distribution Technology (AMDT) Cost Recovery Rider	• The title has been changed to Metering & Distribution Technology (MDT) Cost Recovery Rider. • The Rate Code box on page 1 and the Rate box on page 2 have been updated to properly describe our Controlled Service categories. • Capitalized Customer on page 1 because it is a Glossary term. • Updated Section 14.05 in the Controlled Service Interruptible – Self Contained category of the Rate Box to 14.04. This is necessary due to combining Section 14.04 and 14.05 into one Rate Schedule and Section 14.05 now being Reserved for Future Use. • Moved Section 14.06 (Controlled Service Deferred Load Rider) to the newly titled Controlled Service Deferred Load category.

Section No.	**Section description**	**Changes**
13.12	Interim Rate Rider	*Introduced with Interim Rate Schedules – No changes.*
13.13	NEW Sales Adjustment Rider	• This is a new rider designed to address the impacts of changes on base rate revenues and base rate jurisdictional cost allocations. This is being introduced due to the significant changes in sales between rate cases.
14.00	**Voluntary Riders - Availability Matrix**	• Corrected the title in the header. • Updated several Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Updated the columns for Section 14.04 and 14.05 to show them combined as Section 14.04. Section 14.05 is now Reserved for Future Use. • A correction was made to the indicators in the 14.13 Economic Development Rate Rider – Large General Service column.
14.01	Water Heating Control Rider	• Updated the rates. • Removed “Interim” from the header on page 2. • A Determination of Facilities Charge definition has been added on page 2 as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities. • Removed “Interim” from the header on page 2.
14.02	Real Time Pricing Rider	• Added a new page 6 to this tariff. • Added clarification to the change to the Facilities Demand Charge, reactive demand applicability in the light of the customers CBL demand adjustments at page 2, 5 and 6. • Added language describing the conditions of a potential CBL increase at page 5. • Capitalized Energy, Demand, Reactive Demand and Billing Demand throughout this tariff because they are Glossary terms. • Removed “Interim” from the header on pages 2 – 6.
14.03	Large General Service Rider	• “Facilities Demand” has been added to items to be determined in the Electric Service Agreement in the Electric Service Agreement section on page 1. • Capitalized Commercial on page 1 and 2 because it is a Glossary term. • Removed “Interim” from the header on page 5 and 6.

Section No.	Section description	Changes
14.04	Controlled Service - Interruptible Load CT Metering Rider (Large Dual Fuel)	• Added a new page 4 to this tariff. • Section 14.05, Controlled Service – Interruptible Load Self-Contained Metering Rider (Small Dual Fuel) has been included with this Section 14.04, Controlled Service – Interruptible Load CT Metering Rider (Large Dual Fuel). These Rate Schedules have been combined. • Added clarification of CT with or without ancillary load. • Added to the Self-Contained Metering and CT Metering without Ancillary Load Rate Boxes the following penalty clarification language: During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above. • Updated the rates. • Capitalized Demand, Meter, Facilities Charge Demand, and Billing Demand because they are Glossary terms.
14.05	Controlled Service - Interruptible Load Self-Contained Metering Rider (Small Dual Fuel)	• This Rate Schedule is being cancelled and reserved for future use. A Cancelled version and a Reserved for Future Use version are included. (Section 14.05, Small Dual Fuel, is being combined with Section 14.04, Large Dual Fuel as described above.)
14.06	Controlled Service - Deferred Load Rider (Thermal Storage)	• Updated the rates. • Added to the Rate Box the following penalty clarification language: During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above. • Removed "Interim" from the header on page 3.
14.07	Fixed Time of Service Rider	• Updated the title to include: (Commonly identified as Fixed TOS) • Updated the rates. • Added the following definition of Determination of Facilities Charge: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer's design (rather than metered) demand.
14.08	Air Conditioning Control Rider (**Cool***Savings*)	• Updated the rates. • Updated the Rate Boxes to describe our new Extended Summer Cooling Season. • Updated the Summer Season hours in our Terms and Conditions section on page 2 to describe our new Extended Summer Cooling Season hour.
14.09	Voluntary Renewable Energy Rider	• *No changes – Not included in this filing*

Section No.	**Section description**	**Changes**
	(**Tail***Winds)*	
14.10	WAPA Bill Crediting Program Rider	• *No changes – Not included in this filing*
14.11	Reserved for Future Use	• *No changes – Not included in this filing*
14.12	Bulk Interruptible Service Application and Pricing Guidelines	• Updated the title of the Fixed Charge Determination section to Facilities Charge Determination. • Changed the definition of this Facilities Charge Determination to reference Rules and Regulations Section 5.02 as follows: A fixed charge will be established to recover the Company's investment related costs. Customers served under this rate shall pay a fixed charge according to the language set forth in Section 5.02, Special Facilities.
14.13	Economic Development Rate Rider	• Corrected the numbering error in the Terms and Conditions section. • Inserted “and Voluntary” in the new Terms and Conditions No. 5. • Our standard Mandatory and Voluntary Riders paragraph directing customers to our matrices at Section 12.00, 13.00 and 14.00 has been added to this tariff at page 3 as follows: **MANDATORY AND VOLUNTARY RIDERS:** The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.
15.00	**Retail Electric Service to Communities**	• Corrected Churchs Ferry and Rocklake communities to their proper name.