BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF ANN E. BULKLEY

EXHIBIT 500

November 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am a Principal at The Brattle Group ("Brattle"), a consulting firm that advises clients on regulatory finance and ratemaking issues.

Q. On whose behalf are you testifying in this proceeding?

A. I am submitting this direct testimony before the Public Utility Commission of Oregon ("Commission") on behalf of Cascade Natural Gas Corporation ("Cascade" or the "Company"), a wholly owned subsidiary of MDU Resources Group, Inc. ("MDU Resources").

Q. Please describe your background and professional experience in the energy and utilities industries?

A. I hold a bachelor's degree in economics and finance from Simmons College and a master's degree in economics from Boston University, and have more than 30 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before numerous regulatory agencies. I have advised 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. A summary of my professional and educational background is presented in Exhibit CNGC/501.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

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

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding Cascade's return on equity ("ROE") to be used for ratemaking purposes. I also address the appropriateness of Cascade's proposed capital structure.

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

A. I estimate the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. In consideration of the Commission's past preference for the multi-stage form of the DCF model, I also calculated a multi-stage DCF model but placed limited weight on the results of the multi-stage DCF because the constant growth DCF model is the most appropriate form of the DCF when estimating the cost of equity for a mature industry such as utilities. My recommendation also considers the business and regulatory risk of Cascade relative to the proxy group, and Cascade's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

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 Cascade's cost of equity.

- Section VI explains my selection of the proxy group.
- Section VII describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.
- Section VIII discusses regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for Cascade in this case.
- Section IX provides an assessment of the reasonableness of Cascade's proposed capital structure.
- Section X presents my conclusions and recommendations.

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

A. Yes. My analyses and recommendations are supported by the data presented in Exhibit CNGC/502 through Exhibit CNGC/517, which were prepared by me or under my direction:

- Exhibit CNGC/502 – Summary of ROE Analyses
- Exhibit CNGC/503 – Proxy Group Selection
- Exhibit CNGC/504 – Constant Growth DCF
- Exhibit CNGC/505 – Multi-Stage DCF
- Exhibit CNGC/506 – Long-term GDP Growth Rate
- Exhibit CNGC/507 – CAPM/ECAPM
- Exhibit CNGC/508 – Long-term Beta Analysis
- Exhibit CNGC/509 – Market Return
- Exhibit CNGC/510 – Bond Yield Plus Risk Premium Analysis
- Exhibit CNGC/511 – Size Premium
- Exhibit CNGC/512 – Flotation Cost
- Exhibit CNGC/513 – Capital Expenditures
- Exhibit CNGC/514 – Regulatory Risk Analysis

- Exhibit CNGC/515 – RRA Regulatory Rankings
- Exhibit CNGC/516 – S&P Credit Supportiveness Rankings
- Exhibit CNGC/517 – Capital Structure

III. SUMMARY OF ANALYSIS AND CONCLUSION

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

A. My analyses and recommendations consider the following:

- The United States ("U.S.") Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of Cascade's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Cascade, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider Cascade's

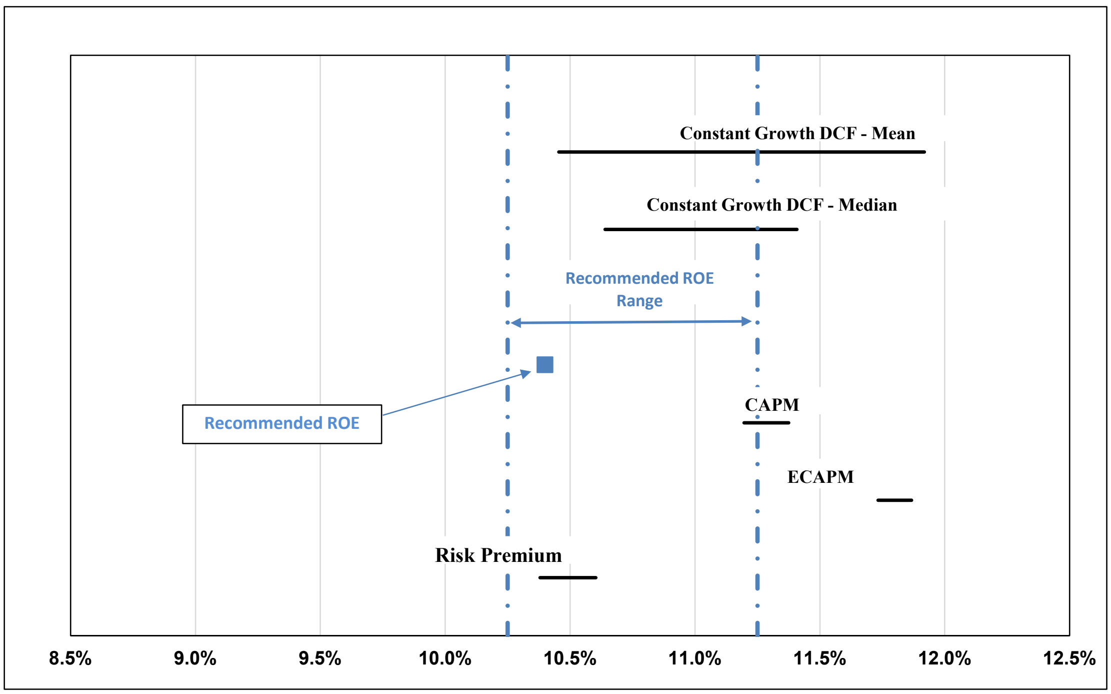
[1] Fed. Power Comm'n v. Hope Nat. Gas Co., 320 US 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 US 679 (1923) ("Bluefield").

regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

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

A. Figure 1 summarizes the range of results produced by the cost of equity analyses based on market data through the end of September 2025.

Figure 1 – Summary of Cost of Equity Analytical Results



Q. What is your recommended ROE for Cascade in this proceeding?

A. Considering the analytical results of the market-based cost of equity models such as the constant growth DCF, CAPM, ECAPM and BYRP, current and prospective capital market conditions and Cascade's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. Additionally, while I do not agree with the use of the multi-stage DCF model, I did place limited weight on the results of the multi-stage DCF model in recognition of the Commission's past preference for the results of the multi-stage DCF model. Considering each of these factors, within the range I recommend an ROE of 10.40 percent. A 10.40 percent ROE is conservative when considering the results of the constant growth DCF, CAPM, ECAPM and BYRP analyses.

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

A. Yes. Cascade's proposed equity ratio of 50.00 percent is well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies and is below the average of the proxy group.

IV. REGULATORY GUIDELINES

Q. Please describe the principles that guide the establishment of 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 allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases by acknowledging that utility investors are entitled to a fair and reasonable return. For example, in its decision in docket UE 433 for PacifiCorp, the Commission stated:

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

> The United States Supreme Court established the standard for determining the cost of capital allowance in setting utility rates: "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"
>
> These constitutional requirements are codified in Oregon statute. As articulated in ORS 756.040(1), rates are sufficient to provide just compensation if they provide "adequate revenue both for operating expenses of the public utility * * * and for capital costs of the utility, with a return to the equity holder that is:
>
> (a) Commensurate with the return on investments in other enterprises having corresponding risks; and
>
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[3]

Q. Is fixing a fair rate of return just about protecting the utility's interests?

A. No. As the Court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

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 electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there

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[3] *In re PacifiCorp, dba Pacific Power, Request for a Gen. Rate Revision (UE 433), Deferred Acct. Related to Wildfire Damage and Restoration Costs (UM 2116), Deferred Acct. for Operating Costs and Capital Investments to Implement the Co.'s Distrib. System Plan (UM 2220), and Deferred Acct. of Deer Creek Mine Royalty Payment Costs (UM 2161)*, Docket No. UE 433, et al., Order No. 24-447 at 6 (Dec. 19, 2024) (quoting Hope, 320 US at 603).
[4] *Bluefield*, 262 US at 679, 693.
[5] *Hope*, 320 US at 591, 603.

is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

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

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

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

Q. Does the fact that Cascade is a subsidiary of MDU Resources, a publicly traded company, affect your analysis?

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

Q. Are the regulatory framework, the authorized ROE, and equity ratio important to the financial community?

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

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. 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 Cascade, which is in the interest of both customers and shareholders.

V. CAPITAL MARKET CONDITIONS

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

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

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

Q. How have interest rates changed since the Company's last rate proceeding?

A. Capital market conditions have changed significantly since Cascade's last rate case proceeding in docket UG 390. These changes indicate that the cost of equity has increased since Cascade's last rate case proceeding in 2020. As shown in Figure 2 below, the yield on the 30-year Treasury bond has increased by 312 basis points since the Commission's order in January 2021 approving the settlement agreement in Cascade's last rate case.[6]

[6] *See In re Cascade Nat. Gas Corp., Request for a Gen. Rate Revision*, Docket No.UG 390, Order No. 21-001 (Jan. 6, 2021).

Figure 2 – Changes in Market Conditions Since Cascade's Last Rate Case[7]

	Date	Federal Funds Rate	30-Day Avg. of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
Docket No. UG 390 Order	1/6/2021	0.09%	1.67%	1.39%	9.40%
Current Case	9/30/2025	4.09%	4.79%	3.11%	-
Change		4.00%	3.12%	1.72%	-

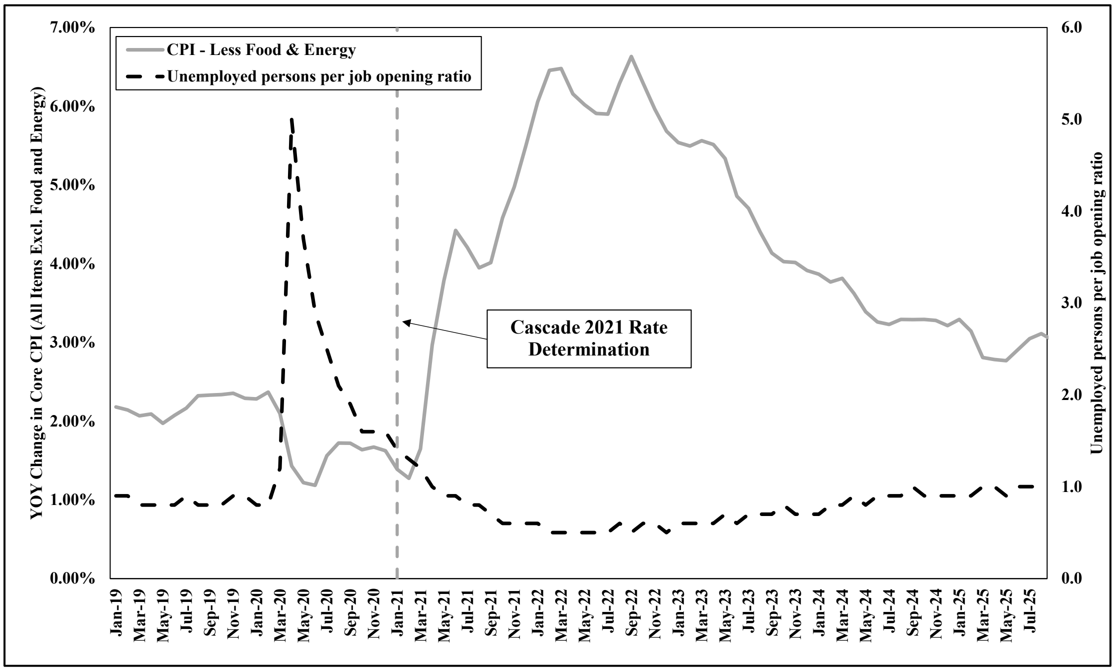
Q. What has the level of inflation been over the past few years?

A. As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.40 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[8] While core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.00 percent.

Because the Federal Reserve's dual mandate is to promote stable prices and employment, considering employment data, in addition to inflation, is important. The ratio of unemployed persons per job opening was 1.0 in August 2025 (the most recent data available at the time of this testimony) and has been consistently at or below 1.00 since April 2021, suggesting a tighter labor market. The strength in the labor market has allowed the Federal Reserve to prioritize reducing inflation by pursuing the restrictive monetary policy needed to achieve its 2.00 percent target benchmark.

[7] St. Louis Federal Reserve Bank; Bureau of Labor Statistics. Core Inflation is as of the end of August, which is the most recent data available at the time of this testimony.
[8] Reade Pickert, *Core US Inflation Rises to 40-Year High, Securing Big Fed Hike*, BLOOMBERG (Oct. 13, 2022), https://www.bloomberg.com/news/articles/2022-10-13/core-us-inflation-rises-to-40-year-high-securing-big-fed-hike.

Figure 3 – Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to September 2025[9]



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

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

[9] Bureau of Labor Statistics; data available data as of November 7, 2025.

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

A. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has increased by over 350 basis points, increasing from 1.47 percent on December 15, 2021, to a peak of 4.98 percent in October 2023. It currently remains well above 2021 levels (i.e., 4.16 percent as of September 30, 2025).[10]

Q. Did the Federal Reserve recently reduce the federal funds rate?

A. Yes. The Federal Reserve reduced the federal funds rate by 50 basis points in September 2024, 25 basis points in November 2024, 25 basis points in December 2024, and more recently 25 basis points in September and October 2025. At the September 2025 meeting, the Federal Reserve noted that it was continuing to assess the risks to both inflation and employment, but that the "downside risks to employment have risen" and, as a result, concluded that it was the appropriate time for a rate decrease after having kept rates unchanged in 2025.[11]

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

A. At the October 2025 Federal Open Market Committee ("FOMC") meeting, Chairman Powell noted that inflation has "eased from its highs in mid-2022," but remains "somewhat elevated" and the labor market is "gradually cooling," and slower job gains "likely reflects a decline in the growth of the labor force."[12] According to Chairman Powell, these recent market developments indicate an increase in the downside risks to employment.[13] As a result, the FOMC reduced the federal funds rate by 25 basis

[10] Bloomberg Professional, as of September 30, 2025.
[11] Press Release, Federal Reserve, Federal Reserve issues FOMC statement (Sept. 17, 2025), available at https://www.federalreserve.gov/newsevents/pressreleases/monetary20250917a.htm.
[12] *Transcript of Chair Powell's Press Conference* at 1, Federal Reserve (Oct. 29, 2025), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20251029.pdf [hereinafter "Chair Powell Tr."].
[13] Chair Powell Tr. at 2.

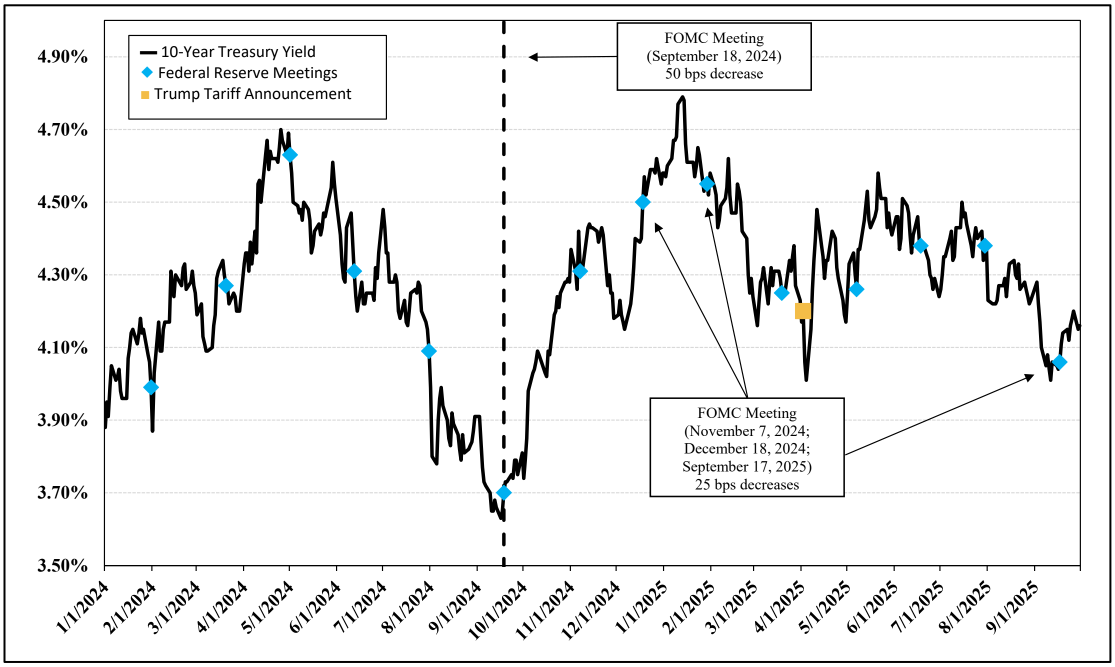
points to a range of 3.75 percent to 4.00 percent.[14] Regarding the possible path of monetary policy, Chairman Powell acknowledged increased uncertainly due to the implementation of government policy changes by the Trump administration, in particular, the changes in tariffs, and that there is still uncertainty whether the effect of tariffs on inflation will be "short-lived" or "more persistent."[15] Given the risks to both inflation and employment, Chairman Powell stated a "further reduction in the policy rate at the December meeting is not a foregone conclusion—far from it. Policy is not on a preset course."[16] Chairman Powell noted that the stance of monetary policy will continue to be based on incoming data and the "balance of risks" and the Federal Reserve remains well positioned to respond to economic developments.[17] While the FOMC did not produce a forecast at the October 2025 meeting, at the September 2025 FOMC meeting, the FOMC forecasted two additional rate cuts before the end of 2025 and one rate cut in 2026.[18]

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

A. As shown in Figure 4 below, while the yield on the 10-year treasury bond declined prior to the time of the first federal funds rate cut, the yield has generally increased since the September 2024 FOMC meeting. As of September 30, 2025, the 10-year Treasury bond yield was 4.16 percent, which is consistent with levels seen in July 2024, several months prior to the reductions in the federal funds rate.

[14] Chair Powell Tr. at 2.
[15] Chair Powell Tr. at 2-3.
[16] Chair Powell Tr. at 3.
[17] Chair Powell Tr. at 3.
[18] Federal Reserve, Summary of Economic Projections, September 17, 2025, at 2.

Figure 4 – 10-Year Treasury Bond Yield, Janaury 2024 through September, 2025[19]



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

A. Investors view key elements of President Trump's economic plan, such as tax cuts, immigration policy, and tariffs, as inflationary.[20] For example, since his inauguration in January 2025, President Trump announced several sets of tariffs on each of the U.S.'s trading partners including but not limited to his announcement on April 2, 2025 implementing a "baseline line" tariff of 10 percent on all imports, reciprocal tariffs on countries that failed to negotiate a trade deal that went into effect on August 7, 2025, as well as the 50 percent tariffs on steel, aluminum, and copper and 25 percent tariffs

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

[20] The increase in long-term government bond yields was initially related to investors responding to an increasing probability of a Trump Administration in 2025 and has continued since President Trump's re-election and inauguration. Davide Barbuscia and Lewis Krauskopf, *Bond rebound uncertain as Trump plans overshadow Fed rate cuts*, REUTERS (Nov. 8, 2024), https://www.reuters.com/markets/rates-bonds/bond-rebound-uncertain-trump-plans-overshadow-fed-rate-cuts-2024-11-08/.

on imported cars.[21] The implemented tariffs are largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bonds payments. In an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation, thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation, which is why inflation risk is greater for long-term government bonds. The significant tariff policy increases the risk that inflation will remain elevated, which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve first reduced the federal funds rate in September 2024. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[22]

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

A. While the Federal Reserve is forecasting additional cuts to the federal funds rate in 2025 and 2026, economists are still expecting elevated long-term interest rates. In the most recently published report by Blue Chip Financial Forecasts, the consensus estimate of economists is that the 30-year treasury bond yield will remain stable and decrease only slightly from 4.70 percent in Q4 2025 to 4.60 percent in Q1 2027.[23] Additionally, the consensus estimate over the longer-term (i.e., 2027-2031) is 4.40 percent.[24] This is important because it means that long-term interest rates are expected to remain elevated during the period that Cascade's rates will be in effect.

[21] Jennifer Clarke, *What Are Tariffs, How Do They Work and Why Is Trump Using Them?*, BBC NEWS (Aug. 27, 2025), https://www.bbc.com/news/articles/cn93e12rypgo.
[22] Karishma Vanjani, *U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982*, BARRON'S (Apr. 9, 2025), https://www.barrons.com/articles/us-treasury-bonds-selloff-market-48ba83be?mod=bol-social-tw.
[23] *Blue Chip Financial Forecasts*, Vol. 44, No. 10, October 1, 2025, at 2.
[24] *Blue Chip Financial Forecasts*, Vol. 44, No. 6, June 2, 2025, at 14.

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

A. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. While the FOMC reduced the federal funds rate at its September and October 2025 meetings, Chairman Powell has indicated that the Federal Reserve will continue to rely on incoming data to determine future adjustments to the federal funds rate. Further, long-term interest rates remain elevated and are expected to continue to remain elevated due to inflationary policies such as tariffs, immigration policy, and tax cuts. With long-term interest rates expected to remain relatively high, borrowing also remains relatively more expensive, which means the cost of capital has increased. As a result, investors demand a higher cost of equity, which means the cost of equity has increased and is expected to remain elevated over the near term

VI. PROXY GROUP SELECTION

Q. Please provide a brief profile of Cascade.

A. Cascade is a natural gas distribution company that is a wholly owned subsidiary of MDU Resources. The Company distributes natural gas to approximately 321,275 residential, commercial, and industrial customers in Washington and Oregon.[25] As of 2024, Cascade distributed natural gas to 84,436 residential, commercial, and industrial customers in several non-contiguous service territories in central and eastern Oregon.[26] Oregon accounted for approximately 10.0 percent of the natural gas distribution operating retail sales revenues of Cascade's parent, MDU Resources, in 2024, while Washington (34.0 percent), Idaho (29.0 percent), North Dakota (12.0 percent), Montana (7.0 percent), South Dakota (5.0 percent), Minnesota

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[25] CNGC/100, Sievert/2.
[26] Public Utility Commission of Oregon, 2024 Oregon Utility Statistics, at 44.

(2.0 percent) and Wyoming (1.0 percent) accounted for the remaining 90.0 percent of the retail gas distribution operating sales revenue.[27] Cascade currently has an investment grade long-term rating of BBB (Outlook: Stable) from S&P Global ("S&P") and BBB (Outlook: Stable) from FitchRatings ("Fitch").[28]

Q. Why have you used a group of proxy companies to estimate the cost of equity for Cascade?

A. In this proceeding, the cost of equity is being estimated for a natural gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and Cascade'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 comparable to Cascade in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

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

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

A. I began with the group of nine companies that Value Line Investment Survey ("Value Line") classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select a group of risk-comparable companies that:

[27] MDU Res. Group Inc., Annual Report (Form 10-K) at 15 (Feb. 20, 2025).
[28] S&P Global Ratings, and FitchRatings, as of October 16, 2025.

- pay consistent quarterly cash dividends, because such companies cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from regulated gas distribution operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. What is the composition of your proxy group?

A. The screening criteria, discussed above, is shown in Exhibit CNGC/503 and results in a proxy group consisting of the companies shown in Figure 5.

Figure 5 – Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas Inc.	OGS
Southwest Gas Corporation	SWX

VII. COST OF EQUITY ESTIMATION

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

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

Q. How is the required cost of equity determined?

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

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

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

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

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 of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints.

Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[29] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[30] recommend the CAPM, DCF, and BYRP approaches.

Q. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A. Yes. In previous cases, the Commission has considered the results of many ROE estimation models and determined, based on the results of those models, whether or not to place any weight on the model in its final determination. For example, in its decision in docket UE 374, the Commission considered the results of the DCF, CAPM and Risk Premium approaches:

> The Commission has previously accepted CAPM as a "useful and reliable addition to the DCF results" for determining cost of equity in certain cases. While we have historically rejected the risk premium analysis as unconventional and because it had not been accepted by other regulatory agencies, we note that [the Federal Energy Regulatory Commission ("FERC")] now gives equal consideration to DCF, CAPM and risk premium results in its approach to establishing ROE.[31]

The Commission also recognized: (1) the effects of the pandemic caused additional uncertainty in the assumptions used in the models; (2) the incremental risk associated with the Company's capital investment plan; and (3) the relationship between the ROE and equity ratio.[32]

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[29] Tom Copeland, Tim Koller, and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies* at 214 (3rd ed. 2000).
[30] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice* at 341 (7th ed. 1994).
[31] *In re of PacifiCorp, dba Pacific Power, Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 30 (Dec. 18, 2020) (internal cites omitted).
[32] Order No. 20-473 at 30-31.

A. 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:

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

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required COE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

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

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

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

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

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 annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days as of September 30, 2025.

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

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

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

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

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

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

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

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

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

Q. Is it appropriate to rely on the constant growth DCF model?

A. Yes. The utility industry is considered a mature industry due to its regulated status and relatively stable demand. Thus, financial projections such as earnings growth rates are also likely to be relatively stable over the long-term. The relative stability of the financial forecasts for utilities supports the use of a constant growth DCF model to estimate the cost of equity for a mature industry like utilities.

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

A. Exhibit CNGC/504 and Figure 6 summarize the results of the constant growth DCF models.

Figure 6 – Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	10.37%	11.03%	11.83%
90-Day Avg. Stock Price	10.47%	11.14%	11.93%
180-Day Avg. Stock Price	10.53%	11.20%	11.99%
Average	**10.45%**	**11.12%**	**11.92%**
Median Results:			
30-Day Avg. Stock Price	10.54%	10.92%	11.30%
90-Day Avg. Stock Price	10.68%	11.07%	11.45%
180-Day Avg. Stock Price	10.70%	11.09%	11.47%
Average	**10.64%**	**11.02%**	**11.41%**

B. <u>Capital Asset Pricing Model</u>

Q. Please briefly describe the Capital Asset Pricing Model.

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.[33] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components:

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

Where:

K_e = the required market cost of equity;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

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

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

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

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

[33] 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.

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

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.79 percent;[34] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2026 through the first quarter of 2027, which is 4.62 percent;[35] and (3) the average projected 30-year U.S. Treasury bond yield for 2027 through 2031, which is 4.40 percent.[36]

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

A. As shown in Exhibit CNGC/507, I use the beta coefficients for the proxy group companies as reported Value Line. The beta coefficients reported by Value Line are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit CNGC/508, 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 2024.

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

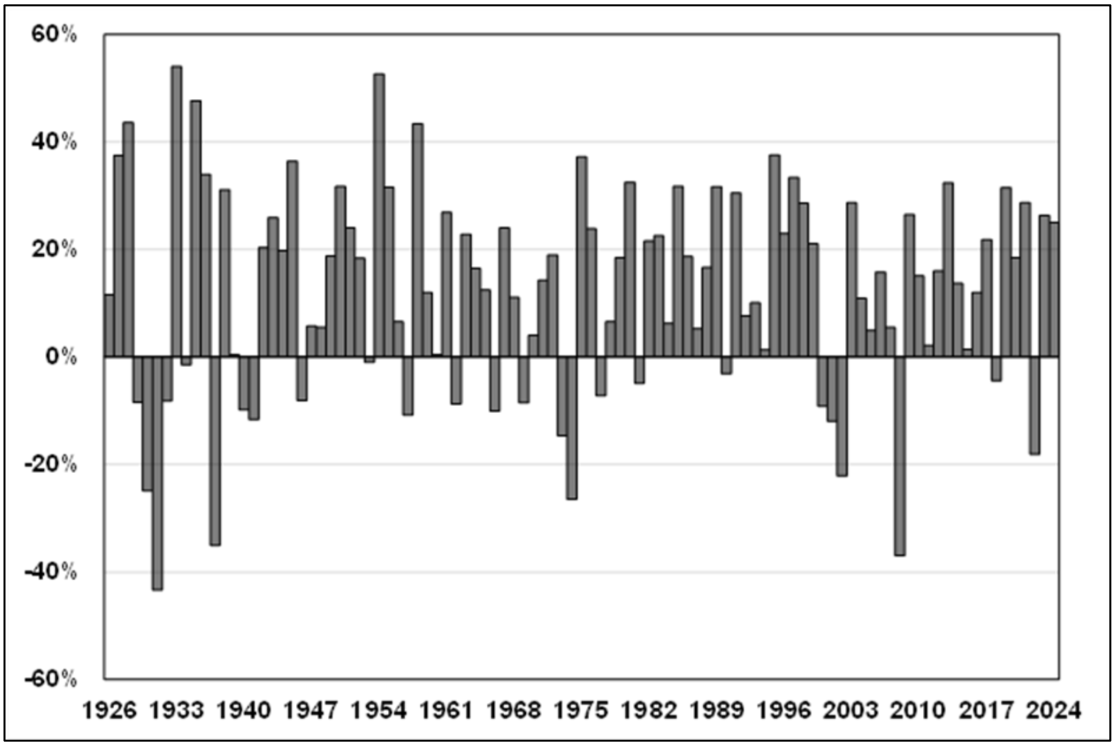
A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit CNGC/509, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.31 percent and a weighted long-term growth rate of 11.95 percent, the estimated required market return for the S&P 500 Index as of September 30, 2025, is 13.34 percent.

[34] Bloomberg Professional, as of September 30, 2025.
[35] *Blue Chip Financial Forecasts*, Vol. 44, No. 10, October 1, 2025, at 2.
[36] *Blue Chip Financial Forecasts*, Vol. 44, No. 6, June 2, 2025, at 14.

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

A. As show in Figure 7, given the range of annual equity returns that have been observed over the past century, a current expected market return of 13.34 percent is reasonable. In 52 out of the past 99 years (or approximately 53 percent of observations), the realized equity market return was at least 13.34 percent or greater.

Figure 7 – Realized U.S. Equity Market Returns (1926–2024)[37]



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

A. Yes. I also consider the results of an ECAPM in estimating the cost of equity for Cascade.[38] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.0 percent to that result. The model

[37] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook for 1926-2022 and from S&P Capital IQ Pro for 2023-2024.
[38] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., June 1, 2006, at 189.

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

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

Where:

k_e = the required market cost of equity;

β = adjusted beta coefficient of an individual security;

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

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

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[39]

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. The results of my CAPM and ECAPM analyses are summarized in Figure 8, as well as presented in Exhibit CNGC/507.

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[39] *Id.* at 191.

Figure 8 – CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.29%	11.25%	11.20%
Long-term Avg. *Value Line* Beta	11.38%	11.34%	11.29%
ECAPM:			
Current *Value Line* Beta	11.80%	11.77%	11.73%
Long-term Avg. *Value Line* Beta	11.87%	11.84%	11.80%

C. <u>Bond Yield Risk Premium Analysis</u>

Q. Please describe your Bond Yield Risk Premium ("BYRP") analysis.

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 holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

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

A. Both academic literature and market evidence indicate that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (i.e., as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit CNGC/510 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[40]

Q. Is the BYRP analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP 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 BYRP analysis reveal?

A. As shown in Figure 9, from January 1980 through September 2025, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

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

Where:

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

a = intercept term

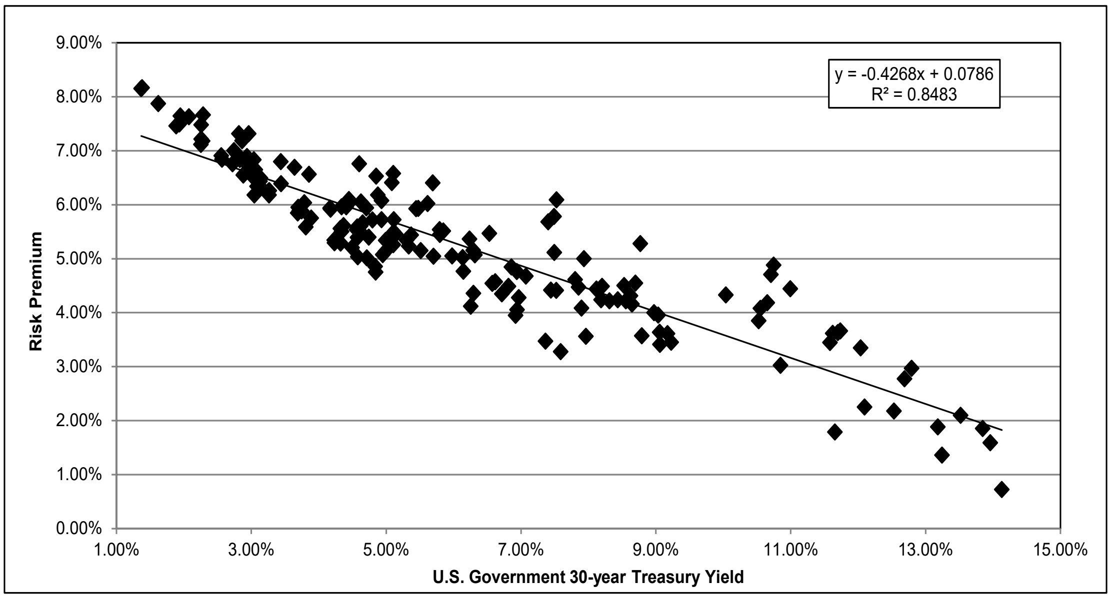
[40] *See, e.g.,* S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, MANAGERIAL AND DECISION ECONOMICS, Vol. 19, No. 2 (Mar. 1998) (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the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

b = slope term

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

Data regarding authorized ROEs were derived from the natural gas utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[41] The equation's coefficients are statistically significant at the 99.00 percent level.

Figure 9 – Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. Figure 10 presents the results of my BYRP analysis, which are also presented in more detail in Exhibit CNGC/510.

Figure 10 – BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.60%	10.51%	10.38%

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

Q. How did the results of the BYRP inform your recommended ROE for Cascade?

A. I consider the results of the BYRP analysis in setting my recommended ROE for Cascade. As noted above, investors consider the ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The BYRP analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of natural gas utilities across the U.S.

D. Multi-Stage DCF Model

Q. Why are you presenting a multi-stage DCF model?

A. Consistent with prior Commission precedent, I have also developed the multi-stage form of the DCF model. As with the constant growth DCF model, the multi-stage form of the model defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows.

Q. Has the Commission expressed a preference for the results of the multi-stage DCF model?

A. Yes, the Commission has indicated that it prefers the results of the multi-stage DCF model. For example, in its decision in docket UE 433, the Commission stated:

> As we have previously stated, determining the cost of equity is not an exact science; instead, based on the information provided, we must determine a reasonable cost of equity in this case. We have discussed the different types of models and the value we derive from looking at multiple models in determining the cost of equity, and have primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE.[42]

[42] Order No. 24-447 at 11 (internal cites omitted).

Q. How does the multi-stage form of the DCF model differ from the constant growth form of the DCF model?

A. As with the constant growth DCF model, the multi-stage form of the model defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. However, the multi-stage DCF model, which is an extension of the constant growth form of the DCF, enables the analyst to specify different growth rates over multiple stages. The multi-stage DCF model allows for a gradual transition from the first-stage growth rate to the long-term growth rate, thereby avoiding the unrealistic assumption that growth changes abruptly between the first and final stages.

Q. What is the structure of the multi-stage DCF model?

A. The multi-stage DCF model sets a company’s current stock price equal to the present value of future cash flows received over three “stages.” In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage One is a short-term growth period that consists of the first ten years; Stage Two is a transition period from the short-term growth period to the long-term growth period, from years 11 through 20; and Stage Three is a long-term growth period that begins in year 21 and continues in perpetuity (i.e., years 21 through 200). The cost of equity is then calculated as the rate of return that results from the initial stock investment and the dividend payments over the analytical period.

Q. Why is it reasonable for the first stage to be 10 years?

A. It is clear the utility industry is in a robust capital investment cycle that is expected to last for some time. It is unreasonable to suggest that the growth in the industry would begin to trend to a gross domestic product (“GDP”) growth rate in five years given the capital investment that is planned across the industry. Therefore, reverting to a GDP growth rate in a later year is more appropriate if one believes there is a need to use a multi-stage DCF model.

Q. What prices do you use in the multi-stage model?

A. I have relied on 30-day, 90-day, and 180-day average stock prices for the proxy group companies, consistent with the averaging periods used for the constant growth DCF model.

Q. What growth rates did you rely on in the multi-stage DCF model?

A. As shown in Exhibit CNGC/505, I began with the current annualized dividend as of September 30, 2025, for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three-to five-year projected EPS growth rate estimates reported by S&P Capital IQ, Zacks, and Value Line that I rely on in the constant growth DCF. For the third stage of the model, I rely on long-term projected growth in GDP. The second stage growth rate is a linear transition from the first stage growth rate to the long-term growth rate.

Q. How did you calculate the long-term GDP growth rate?

A. As shown in Exhibit CNGC/506, the projected long-term growth rate is 5.45 percent, which is based on real GDP growth rate of 3.18 percent from 1929 through 2024,[43] plus a projected inflation rate of 2.20 percent. The projected inflation rate is based on three measures: (1) the average long-term projected growth rate in the CPI of 2.20 percent;[44] (2) the compound annual growth rate of the CPI for all urban consumers for 2035-2050 of 2.23 percent as projected by the Energy Information Administration ("EIA");[45] and (3) the compound annual growth rate of the GDP chain-type price index for 2035-2050 of 2.18 percent, also reported by the EIA.[46]

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[43] U.S. Bureau of Economic Analysis, "Table 1.1.6. Real Gross Domestic Product, Chained Dollars" (last accessed Oct. 1, 2025).
[44] *Blue Chip Financial Forecasts*, Vol. 44, No. 6 June 2, 2025, at 14.
[45] Energy Information Administration, Annual Energy Outlook 2025 at Table 20 (Apr. 15, 2025).
[46] *Id.*

Q. What are the results of your multi-stage DCF model?

A. Exhibit CNGC/505 and Figure 11 summarize the results of the multi-stage DCF models.

Figure 11 – Summary of Multi-Stage DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.52%	9.82%	10.20%
90-Day Avg. Stock Price	9.65%	9.95%	10.34%
180-Day Avg. Stock Price	9.72%	10.03%	10.43%
Average	**9.63%**	**9.93%**	**10.32%**
Median Results:			
30-Day Avg. Stock Price	9.22%	9.51%	9.88%
90-Day Avg. Stock Price	9.29%	9.58%	9.97%
180-Day Avg. Stock Price	9.40%	9.70%	10.09%
Average	**9.30%**	**9.60%**	**9.98%**

Q. Is it appropriate to consider a multi-state DCF model?

A. No. As noted previously, the utility industry is considered a mature industry due to its regulated status and relatively stable demand, therefore it is reasonable and appropriate to rely on the constant growth DCF, as I have presented in Figure 1. However, while I do not believe it is appropriate to consider the results of a multi-stage DCF model, in recognition of the Commission's past preference for the multi-stage DCF model, I have placed limited weight on the results of the multi-stage DCF model when determining my recommended ROE for Cascade.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for Cascade?

A. No. These results provide only a range of the appropriate estimate of Cascade's cost of equity. Several additional factors must be considered when determining where the

Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on Cascade's risk profile relative to the proxy group.

A. Small Size Risk

Q. Is there a risk to a firm associated with small size?

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.[47]

Q. How does the smaller size of a utility affect its business risk?

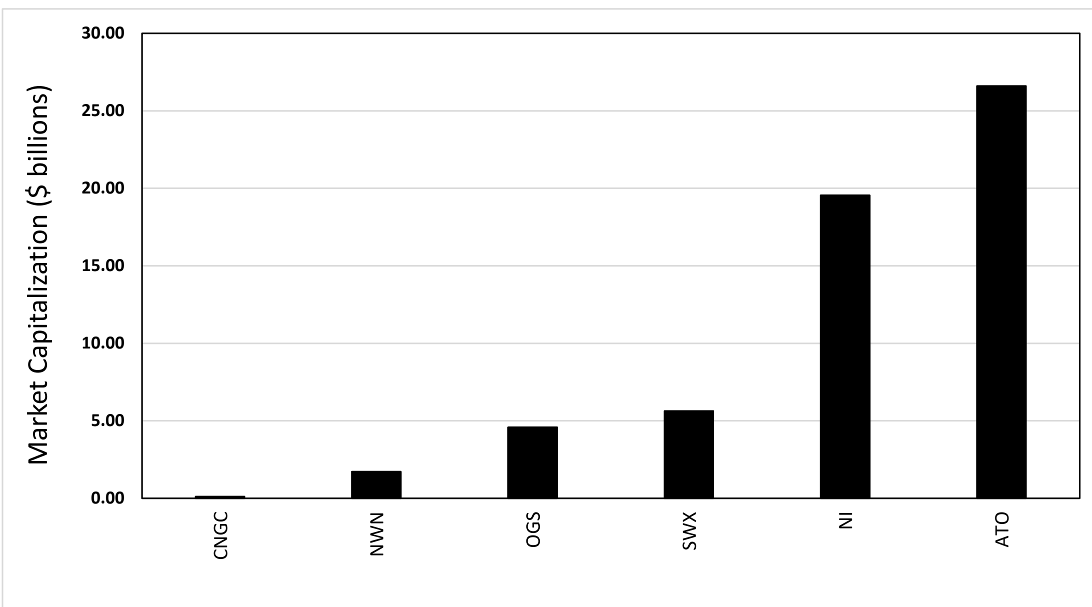
A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility 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.

[47] Michael Annin, *Equity and the Small-Stock Effect*, PUB. UTILS. FORTNIGHTLY, Oct. 15, 1995, at 42.

Q. How do Cascade's natural gas operations in Oregon compare in size to those of the proxy group companies?

A. Comparing the common equity of Cascade's natural gas operations in Oregon to the proxy group demonstrates that the Company is substantially smaller than the median of the proxy group. Exhibit CNGC/511 provides the actual market capitalization for the proxy group companies and estimates the common equity for Cascade (i.e., the implied market capitalization if the Company's natural gas service operations in Oregon were a stand-alone publicly traded entity). Figure 12 below shows that the common equity for Cascade's natural gas operations in Oregon is lower than all of the proxy group companies.

Figure 12 – Market Capitalization of the Proxy Group Companies and the Common Equity of Cascade [48]



[48] To estimate the size of Cascade relative to the proxy group, I calculate the equity balance of Cascade's capital structure of $115.44 million by multiplying Cascade's test year rate base by the Company's proposed common equity ratio of 50.00 percent.

Q. How did you estimate the size premium for Cascade?

A. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for Cascade using Kroll Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[49] As shown in Exhibit CNGC/511, the median market capitalization of the proxy group is approximately \$5.64 billion, which corresponds to the fifth decile of Kroll's market capitalization data.[50] Based on Kroll's analysis, that decile corresponds to a size premium of 0.74 percent (i.e., 74 basis points). In comparison, Cascade's common equity of approximately \$115.44 million falls within the tenth decile, which corresponds to a size premium of 4.47 percent (i.e., 447 basis points). The difference between the size premium for Cascade and the size premium for the proxy group is 373 basis points (i.e., 4.47 percent minus 0.74 percent).

Q. Have utility companies been included in the Kroll size premium study conducted?

A. Yes. For example, 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.[51]

Q. Is the size premium applicable to companies in regulated industries such as utilities?

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

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[49] Kroll, Cost of Capital Navigator – Size Premium: Annual data as of December 31, 2024.
[50] *Id*.
[51] *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

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.[52] 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, 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.[53]

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.[54] 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.[55]

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. For example, in Order No. 15 in docket U-10-029, 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

[52] Thomas M. Zepp, *Utility Stocks and the Size Effect—Revisited*, THE QUARTERLY REVIEW OF ECONOMICS AND FINANCE, Vol. 43, No. 3 at 578-582 (2003).
[53] *Id*.
[54] Stéphane Chrétien and Frank Coggins, *Cost of Equity For Energy Utilities: Beyond The CAPM*, ENERGY STUDIES REVIEW, Vol. 18, No. 2 (2011).
[55] *Id*.

risks.[56] 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."[57] Thus, the RCA awarded AEL&P an ROE of 12.875 percent,[58] which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[59] Similarly, the RCA has also noted that small size, as well as other business risks such as its substantial transmission assets, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation, and economic conditions, increased the risk of ENSTAR Natural Gas Company ("ENSTAR").[60] 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.[61]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail'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.[62]

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[56] *In re the Revenue Requirement and Cost of Serv. Study Designated as TA381-1 Filed by Alaska Elec. Light and Power Co.*, Docket No. U-10-029, Order No. 15 at 37 (Sept. 2, 2011).
[57] RCA Order No. 15 at 37.
[58] RCA Order No. 15 at 37.
[59] *See* RCA Order No. 15 at 32.
[60] *In re the Tariff Revision Designated as TA285-4 Filed by ENSTAR Nat. Gas Co., A Division of SEMCO Energy, Inc.*, Docket No. U-16-066, Order No. 19 at 50-52 (Sept. 22, 2017).
[61] RCA Order No. 19 at 52.
[62] *In re the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order at 55 (May 1, 2017).

Finally, in Opinion Nos. 569 and 569-A, FERC adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[63]

Q. How have you considered the smaller size of Cascade in your recommendation of the Company's ROE in this proceeding?

A. While I have estimated the effect of Cascade's small size on the ROE, I am not proposing a specific adjustment for this risk factor. Rather, I consider the small size of Cascade's natural gas operations in Oregon, along with the other risk factors present for Cascade, in determining where, within the range of analytical results, my recommended ROE for the Company should fall. All else equal, the additional risk associated with Cascade's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. <u>Flotation Costs</u>

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

[63] *Ass'n. of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 75 (May 21, 2020). The U.S. Court of Appeals vacated FERC Opinion 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. *Miso Transmission Owners v. FERC*, 45 F 4th 248, 260 (2022).

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 cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny the Company the opportunity to earn its required rate of return in the future.

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

A. Yes. Suppose MDU Resources issues stock with a value of $100, and an equity investor invests $100 in MDU Resources in exchange for that stock. Further, suppose that after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU Resources ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU Resources then 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 the investor 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 need to consider flotation costs eliminated because Cascade is a wholly owned subsidiary of MDU Resources?

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

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

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

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[64]

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

Q. How did you calculate the flotation costs for Cascade?

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU Resources in its two most recent common equity issuances. That flotation cost percentage is then applied to the proxy group in the DCF analysis to estimate the impact on the cost of equity associated with flotation costs. As shown in Exhibit CNGC/512, based on the flotation costs previously incurred by MDU Resources, the impact on the proxy group's cost of equity amounts to 18 basis points (i.e., 0.18 percent) based on the median and 13 basis points (i.e., 0.13 percent) based on the mean.

Q. Does your final cost of equity results include an adjustment for flotation cost recovery?

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

C. <u>Capital Expenditures</u>

Q. What are Cascade's projected capital expenditure requirements over the next few years?

A. As of December 31, 2024, Cascade had net utility plant of approximately $217.6 million,[65] and the Company currently projects capital expenditures for 2026 through 2030 of approximately $145.42 million,[66] which represent approximately 66.84 percent of its current net utility plant.

[65] Data provided by Cascade.
[66] Data provided by Cascade.

Q. How do Cascade's capital expenditure requirements compare to those of the proxy group companies?

A. As shown Exhibit CNGC/513, I have calculated the ratio of expected capital expenditures to net utility plant for Cascade and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2026 through 2030 by its total net utility plant as of December 31, 2024. As shown, Cascade's ratio of capital expenditures as a percentage of net utility plant is slightly greater than the median for the proxy group companies of 65.16 percent.

Q. How is Cascade'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 significant capital expenditures?

A. Yes. 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 a significant amount of 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 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.[67]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured.[68]

Therefore, to the extent that Cascade's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does the Company currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. No. However, in the current proceeding, Cascade is requesting approval of a renewable natural gas ("RNG") recovery mechanism to recover its costs for future renewable natural gas infrastructure. Although, it is important to note that if approved the Company would only recover a limited portion of its capital costs through the RNG

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[67] S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments* at 7 (Aug. 10, 2016).

[68] S&P Global Ratings, *Industry Credit Outlook 2025, North American Regulated Utilities: Capex and climate change pressures credit quality* at 10 (Jan. 14, 2025).

recovery mechanism and thus would still rely on rate case filings for capital cost recovery.

Q. Are capital investment recovery mechanisms common amongst natural gas utilities?

A. Yes. Significant capital programs, like Cascade's, generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit CNGC/514, approximately 77.27 percent of the companies in the proxy group currently have mechanisms for some form of capital cost recovery in place. Therefore, if approved, the RNG recovery mechanism would not provide any incremental risk mitigation for the financial risks associated with capital expenditures relative to the proxy group. However, absent approval of the RNG recovery mechanism, Cascade would have greater risk from a capital expenditure standpoint than the proxy group companies.

Q. What are your conclusions regarding the effect of Cascade's capital spending requirements on its risk profile and cost of capital?

A. Cascade's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, if the RNG recovery mechanism is approved, similar to the vast majority the operating utilities of the proxy group, Cascade would have a capital tracking mechanism to recover a limited portion of the Company's projected capital expenditures, albeit more limited in scope than such clauses in other jurisdictions. Further, absent approval of the RNG recovery mechanism, the Company's risk regarding the timely recovery of capital expenditures would increase relative to the proxy group.

D. Climate Policy

Q. Please summarize the effect of climate policy in Oregon on natural gas distribution utilities.

A. In 2021, the Environmental Quality Commission ("EQC") of the Oregon Department of Environmental Quality ("DEQ") voted to adopt an initial version of the Climate Protection Program ("CPP") with implementation of the program beginning in 2022.[69] While the initial version of the program was invalidated by a court decision in 2023, a revised CPP was adopted by the EQC and went into effect in January 2025.[70] The revised CPP established a declining cap on greenhouse gas emissions from fossil fuels used in Oregon including diesel, gasoline, natural gas and propane. Specifically, the revised CPP requires reductions in emissions of 50 percent by 2035 and 90 percent by 2050 relative to 2017-2019 levels.[71]

Q. Have ratings agencies commented on risk associated with decarbonization policies?

A. Yes. Moody's has commented on the risk of decarbonization policies to natural gas utilities:

> Decarbonization policies pose biggest threat to LDC business model. Emissions reduction and electrification initiatives call into question the long-term ability of natural gas local distribution companies (LDCs) to maintain their position as natural gas monopoly service providers. Government policies requiring significantly lower emissions could eventually reduce the size of LDCs over time and make them less competitive by driving up their costs.[72]

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[69] Oregon Department of Environmental Quality, Climate Protection Plan: 2021 Resources, https://www.oregon.gov/deq/ghgp/cpp/Pages/modelingstudy.aspx.
[70] *Id.*
[71] Oregon Department of Environmental Quality, CPP Fact Sheet, https://www.oregon.gov/deq/ghgp/Documents/cppOverviewFS.pdf.
[72] Moody's Investors Service, *Emissions reduction, electrification threaten long-term competitiveness*, Sector in-Depth at 1 (Nov. 14, 2022).

Further, Moody's noted that policy and regulatory support to facilitate the energy transition, including clear and measured approaches that limit uncertainty, was important for LDCs to maintain their long-term credit quality.[73]

E. Regulatory Risk

Q. How does the regulatory environment affect 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 the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. Cascade is no exception. Therefore, 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, a utility's financial profile

[73] *Id.*

must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

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 (i.e., 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. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent, while diversification which considers diversity in terms of regulatory jurisdictions is afforded a rating factor of 10.00 percent. Therefore, Moody's assigns regulatory risk a 60.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[74]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[75] S&P identifies four specific factors that it uses to assess the

[74] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities* at 2 (Aug. 6, 2024).
[75] S&P Global Ratings, *Sector-Specific Corporate Methodology* at 147 (Apr. 4, 2024).

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.[76]

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, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[77] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[78]

Q. Have credit rating agencies recently identified any risk factors for utilities operating in Oregon?

A. Yes. Regulatory Research Associates ("RRA") views aspects of House Bill ("HB") 3179, which was recently passed by the Oregon Legislature, as "negative" from an investor perspective.[79] Specifically, RRA notes that HB 3179: (1) prohibits electric and natural gas rate increases within 18 months from the date of a utility's last authorized rate increase; (2) limits the number of natural gas and electric utilities that

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[76] *Id.*
[77] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities* at 8 (Aug. 6, 2024).
[78] *Id.*
[79] RRA Regulatory Focus, *New Ore. Legislation aims to constrain electric, gas ratemaking activity*, July 10, 2025; *see also* HB 3179, 83rd Or. Leg. Assemb., 2025 Reg. Sess. (Or. 2025).

can file for a rate increase in a given year; (3) prohibits residential rate increases between November 1st and March 31st; and (4) allows the Commission to adjust residential rates to mitigate rate increases.[80]

Q. Have you conducted an analysis to compare the cost recovery mechanisms of Cascade to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Oregon based on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e., forecast vs. historical); (2) use of rate design or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. Each are described below and are summarized in Exhibit CNGC/514.

Test Year Convention: Cascade is proposing a fully forecasted test year in Oregon. As shown in Exhibit CNGC/514, approximately 45.45 percent of the utility operating subsidiaries of the companies in the proxy group also have either partially or fully forecast test years. See the Direct Testimony of Travis Jacobson for discussion of the need for a fully forecasted test year in this case.[81]

Volumetric Risk: Cascade has partial protection against volumetric risk in Oregon through its Conservation Alliance Plan Adjustment which is a revenue decoupling mechanism applicable to the residential and general commercial rate classes. Similarly, approximately 95.45 percent of the operating companies held by the proxy group have some form of protection against volumetric risk through either revenue decoupling mechanisms, formula rate plans, or straight fixed-variable rate design.

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[80] *Id.*
[81] CNGC/600, Jacobson/8-15.

Capital Cost Recovery: While Cascade does not currently have a capital tracking mechanism to recover capital investment costs between rate cases, the Company is requesting approval of the RNG recovery mechanism which would allow Cascade to recover a limited portion of its projected capital investments between rate cases. As noted previously, approximately 77.27 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Q. What is the effect of Cascade having relatively fewer timely cost recovery mechanisms?

A. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q. Is there evidence that Cascade has been unable to earn its authorized return?

A. Yes. As discussed in the Direct Testimony of Stephanie Sievert, the Company has been significantly under-earning its authorized return in recent years.[82]

Q. Do you develop any additional analyses to evaluate the regulatory environment in Oregon as compared to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I conduct two additional analyses to compare the regulatory framework of Oregon to the jurisdictions in which the companies in the proxy group operate. Specifically, I

[82] CNGC/100, Sievert/12.

consider two different rankings: (1) RRA's ranking of regulatory jurisdictions; and (2) S&P's ranking of credit supportiveness of regulatory jurisdictions.

Q. Please explain how RRA evaluates regulatory environment in each jurisdiction.

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, company and government outreach.

Q. How do you use RRA ratings to compare the regulatory jurisdictions of the proxy companies with Cascade's regulatory jurisdiction?

A. RRA assigns a ranking for each regulatory jurisdiction as "Above Average," "Average," or "Below Average," and then within each of those categories, a numeric ranking from 1 to 3. Thus, there are a total of nine RRA rankings, with the rankings for each jurisdiction ranging from "Above Average/1," which is considered the most supportive, to "Below Average/3," which is the least supportive. I apply a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking (i.e., a "1") and "Below Average/3" assigned the lowest ranking (i.e., a "9"). As shown in Exhibit CNGC/515, Oregon's jurisdictional ranking is "Average/3" (i.e., a "6"), which is below the proxy group average ranking of between "Average/1" and "Average/2" (i.e., a "4.95"). In June 2025, RRA lowered its regulatory ranking of Oregon from "Average/2" to "Average/3".

Q. How did you conduct your analysis of the S&P credit supportiveness?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Most Credit Supportive" down to "Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate as compared to Cascade's regulatory jurisdiction was similar to the analysis of the RRA overall regulatory ranking discussed above. Specifically, I assigned a numerical ranking to each category, from Most Credit Supportive (i.e., a "1") to Credit Supportive (i.e., a "5"). As shown on Exhibit CNGC/516, Oregon's jurisdictional classification of "More Credit Supportive" (i.e., a "4") is below the proxy group average ranking of 2.40, which would be classified between "Highly Credit Supportive" and "Very Credit Supportive".

Q. What are your conclusions regarding the perceived risks related to the regulatory environment in Oregon?

A. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms of Cascade relative to the proxy group, many of the companies in the proxy group have more timely cost recovery between rate proceedings. In addition, the RRA jurisdictional ranking and the S&P credit supportiveness ranking for Oregon indicate greater than average risk relative to the proxy group. Finally, the Company has significantly under-earned its authorized return in recent years. For these reasons, I conclude that Cascade has greater than average regulatory risk relative to the proxy group.

IX. CAPITAL STRUCTURE

Q. Is the capital structure of Cascade an important consideration in the determination of the appropriate ROE?

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

Q. What is Cascade's proposed capital structure?

A. Cascade proposes to establish a capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt.

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

A. Yes. I compare Cascade's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to Cascade; however, those companies must be publicly traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to Cascade, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I calculate the average proportion of common equity, long-term debt, and preferred equity for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit CNGC/517, the common equity ratios for operating subsidiaries of the proxy group companies range from 46.51 percent to 65.95 percent, with an average of 55.36 percent. Therefore, Cascade's proposed equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies and, in fact, is well below the average.

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 Cascade's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, Moody's recently maintained its "stable" 2025 outlook for the regulated gas and electric utilities sector on the expectation of continued regulatory support, which includes supportive legislature, timely recovery of excess purchased power costs, and weather-related cost recovery. Moody's "stable" rating also considers its expectation for declining interest rates and inflation, as well as favorable natural gas prices. Moody's makes clear that constructive regulatory outcomes that promote timely cost recovery is the key factor in supporting utility credit quality.[83]

S&P continues to maintain a negative outlook for the utility industry, noting that downgrades have outpaced upgrades for the fifth consecutive year and the most common investor-owned utility credit rating is a "BBB+".[84] S&P expects the industry to have increased cash flow deficits as a result of significant capital spending.[85] Weak common equity issuance contributes pressure to the industry's financial health. The utility industry will need ongoing access to capital markets to fund the capital expenditures. Furthermore, S&P also notes that there is a significant increase physical risk due to climate change and elevated wildfire risk.

[83] Moody's Investors Service, Outlook, *Outlook Stable; regulatory support, economic factors offset financial pressure*, Nov. 7, 2024.
[84] S&P Global Ratings, Industry Credit Outlook 2025, *North American Regulated Utilities: Capex and climate change pressure credit quality*, Jan. 14, 2025.
[85] *Id*.

Fitch Ratings ("Fitch") has a "neutral" outlook for the utility industry noting that moderation in inflation and "subdued" commodity costs have eased pressures on customer bills. However, Fitch cautions that utility capital expenditures are expected to grow at a "double-digit rate" and thus, rate case outcomes will be key to watch as regulators balance rate requests and customer bill pressures.[86]

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

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

A. Yes. The level of earnings authorized by the Commission directly affects Cascade's ability to fund its operations with internally generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally generated funds.

It also is important to realize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Consequently, both the ROE and capital structure are very important to debt and equity investors. Furthermore, considering the capital market conditions discussed above in Section V, the authorized ROE and capital structure take on even greater significance.

[86] Fitch Ratings, *North American Utilities, Power & Gas Outlook 2025*, Dec. 5, 2024, at 1.

Q. What is your conclusion regarding an appropriate equity ratio for Cascade?

A. Considering the actual capital structures of the utility operating subsidiaries of the proxy group, I believe that Cascade's proposed common equity ratio of 50.00 percent is reasonable. The proposed equity ratio is well below the average equity ratio established by the capital structures of the utility operating subsidiaries of the proxy companies, which would suggest that Cascade has greater financial risk than the proxy group.

X. CONCLUSION AND RECOMMENDATIONS

Q. What is your conclusion regarding a fair ROE for Cascade?

A. Figure 13 summarizes the results of my cost of equity analyses. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of Cascade compared to the proxy group, and current and prospective conditions in capital markets, it is my view that a reasonable range for the Company's ROE is from 10.25 percent to 11.25 percent. Additionally, while I do not agree with the use of the multi-stage DCF model, I did place limited weight on the results of the multi-stage DCF model in recognition of the Commission's past preference for the results of the multi-stage DCF model. Considering each of these factors, within the range I recommend an ROE of 10.40 percent.

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Figure 13 – Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Average	10.37%	11.03%	11.83%
90-Day Average	10.47%	11.14%	11.93%
180-Day Average	10.53%	11.20%	11.99%
Average	10.45%	11.12%	11.92%
Median Results:			
30-Day Average	10.54%	10.92%	11.30%
90-Day Average	10.68%	11.07%	11.45%
180-Day Average	10.70%	11.09%	11.47%
Average	10.64%	11.02%	11.41%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Value Line Beta	11.29%	11.25%	11.20%
Long-Term Avg. Beta	11.38%	11.34%	11.29%
ECAPM:			
Value Line Beta	11.80%	11.77%	11.73%
Long-Term Avg. Beta	11.87%	11.84%	11.80%
Bond Yield Risk Premium	10.60%	10.51%	10.38%

Q. What is your conclusion regarding Cascade's proposed capital structure?

A. Cascade's proposed capital structure consisting of 50.00 percent common equity, and 50.00 percent long-term debt is reasonable when compared to the capital structures of the companies in the proxy group.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

WITNESS QUALIFICATIONS OF ANN E. BULKLEY

EXHIBIT 501

November 2025

Brattle

Ann E. Bulkley

PRINCIPAL

Boston | 508.981.0866 | Ann.Bulkley@brattle.com

With more than 30 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

Brattle

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.

EXPERT TESTIMONY

Ms. Bulkley has provided expert testimony before the following regulatory commissions, courts and boards:

- **Arizona Corporation Commission**
- **Arkansas Public Service Commission**
- **California Public Utilities Commission**
- **Colorado Public Utilities Commission**
- **Connecticut Public Utilities Regulatory Authority**
- **Federal Energy Regulatory Commission**
- **Idaho Public Utilities Commission**
- **Illinois Commerce Commission**
- **Indiana Utility Regulatory Commission**
- **Iowa Utilities Board**
- **Kansas Corporation Commission**
- **Kentucky Public Service Commission**
- **Maine Public Utilities Commission**
- **Maryland Public Service Commission**

- Massachusetts Appellate Tax Board
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Michigan Tax Tribunal
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Public Utilities Commission of Nevada
- New Hampshire - Board of Tax and Land Appeals
- New Hampshire Public Utilities Commission
- New Hampshire-Merrimack County Superior Court
- New Hampshire-Rockingham Superior Court
- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission
- New York State Department of Public Service
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Service Commission
- Oregon Public Service Commission
- Pennsylvania Public Utility Commission
- South Dakota Public Utilities Commission
- Tennessee Public Utility Commission
- Texas Public Utility Commission
- Texas Railroad Commission
- Utah Public Service Commission
- Virginia State Corporation Commission
- Washington Utilities Transportation Commission

- **West Virginia Public Service Commission**
- **Wisconsin Public Service Commission**
- **Wyoming Public Service Commission**

CERTIFICATIONS/ACCREDITATIONS

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

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

SUMMARY OF ROE ANALYSIS

EXHIBIT 502

November 2025

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS AS OF SEPTEMBER 30, 2025

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Average	10.37%	11.03%	11.83%
90-Day Average	10.47%	11.14%	11.93%
180-Day Average	10.53%	11.20%	11.99%
Average	10.45%	11.12%	11.92%
Median Results:			
30-Day Average	10.54%	10.92%	11.30%
90-Day Average	10.68%	11.07%	11.45%
180-Day Average	10.70%	11.09%	11.47%
Average	10.64%	11.02%	11.41%

Multi-Stage DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Average	9.52%	9.82%	10.20%
90-Day Average	9.65%	9.95%	10.34%
180-Day Average	9.72%	10.03%	10.43%
Average	9.63%	9.93%	10.32%
Median Results:			
30-Day Average	9.22%	9.51%	9.88%
90-Day Average	9.29%	9.58%	9.97%
180-Day Average	9.40%	9.70%	10.09%
Average	9.30%	9.60%	9.98%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Value Line Beta	11.29%	11.25%	11.20%
Long-Term Avg. Beta	11.38%	11.34%	11.29%
ECAPM:			
Value Line Beta	11.80%	11.77%	11.73%
Long-Term Avg. Beta	11.87%	11.84%	11.80%
Bond Yield Risk Premium	10.60%	10.51%	10.38%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

PROXY GROUP SELECTION

EXHIBIT 503

November 2025

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Regulated Operating Income / Total Opertating Income > 70%	% Regulated Natural Gas Operating Income / Regulated Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A-	Yes	100.00%	64.53%	No
NiSource Inc.	NI	Yes	BBB+	Yes	99.44%	66.50%	No
Northwest Natural Gas Company	NWN	Yes	A-	Yes	99.75%	91.14%	No
ONE Gas Inc.	OGS	Yes	A-	Yes	100.00%	100.00%	No
Southwest Gas Corporatior	SWX	Yes	BBB+	Yes	86.42%	90.89%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] Source: Form 10-K's for 2024, 2023, and 2022
[5] Source: Form 10-K's for 2024, 2023, and 2022
[6] Source: SNL Financial News Releases

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CONSTANT GROWTH DCF

EXHIBIT 504

November 2025

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$165.62	2.10%	2.18%	7.00%	7.30%	7.22%	7.17%	9.17%	9.35%	9.48%
NiSource Inc.	NI	$1.12	$41.53	2.70%	2.81%	9.50%	7.90%	8.44%	8.61%	10.70%	11.43%	12.33%
Northwest Natural Gas Company	NWN	$1.96	$42.14	4.65%	4.79%	6.50%	n/a	5.75%	6.13%	10.54%	10.92%	11.30%
ONE Gas Inc.	OGS	$2.68	$76.30	3.51%	3.61%	4.50%	5.60%	5.94%	5.35%	8.09%	8.95%	9.56%
Southwest Gas Corporation	SWX	$2.48	$78.30	3.17%	3.34%	10.00%	10.40%	13.11%	11.17%	13.33%	14.51%	16.49%
Mean				3.23%	3.35%	7.50%	7.80%	8.09%	7.69%	10.37%	11.03%	11.83%
Median				3.17%	3.34%	7.00%	7.60%	7.22%	7.17%	10.54%	10.92%	11.30%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$158.64	2.19%	2.27%	7.00%	7.30%	7.22%	7.17%	9.27%	9.45%	9.57%
NiSource Inc.	NI	$1.12	$40.71	2.75%	2.87%	9.50%	7.90%	8.44%	8.61%	10.76%	11.48%	12.38%
Northwest Natural Gas Company	NWN	$1.96	$40.87	4.80%	4.94%	6.50%	n/a	5.75%	6.13%	10.68%	11.07%	11.45%
ONE Gas Inc.	OGS	$2.68	$74.02	3.62%	3.72%	4.50%	5.60%	5.94%	5.35%	8.20%	9.06%	9.67%
Southwest Gas Corporation	SWX	$2.48	$76.00	3.26%	3.45%	10.00%	10.40%	13.11%	11.17%	13.43%	14.62%	16.59%
Mean				3.32%	3.45%	7.50%	7.80%	8.09%	7.69%	10.47%	11.14%	11.93%
Median				3.26%	3.45%	7.00%	7.60%	7.22%	7.17%	10.68%	11.07%	11.45%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 90-day average as of September 30, 2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$153.71	2.26%	2.35%	7.00%	7.30%	7.22%	7.17%	9.34%	9.52%	9.65%
NiSource Inc.	NI	$1.12	$39.53	2.83%	2.96%	9.50%	7.90%	8.44%	8.61%	10.84%	11.57%	12.47%
Northwest Natural Gas Company	NWN	$1.96	$40.72	4.81%	4.96%	6.50%	n/a	5.75%	6.13%	10.70%	11.09%	11.47%
ONE Gas Inc.	OGS	$2.68	$73.30	3.66%	3.75%	4.50%	5.60%	5.94%	5.35%	8.24%	9.10%	9.70%
Southwest Gas Corporation	SWX	$2.48	$74.00	3.35%	3.54%	10.00%	10.40%	13.11%	11.17%	13.52%	14.71%	16.68%
Mean				3.38%	3.51%	7.50%	7.80%	8.09%	7.69%	10.53%	11.20%	11.99%
Median				3.35%	3.54%	7.00%	7.60%	7.22%	7.17%	10.70%	11.09%	11.47%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 180-day average as of September 30, 2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

MULTI-STAGE DCF

EXHIBIT 505

November 2025

30-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$165.62	7.00%	6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	8.11%
NiSource Inc.	NI	$1.12	$41.53	7.90%	7.68%	7.46%	7.23%	7.01%	6.79%	6.57%	6.34%	6.12%	5.90%	5.68%	5.45%	9.22%
Northwest Natural Gas Company	NWN	$1.96	$42.14	5.75%	5.72%	5.70%	5.67%	5.64%	5.62%	5.59%	5.56%	5.54%	5.51%	5.48%	5.45%	10.62%
ONE Gas Inc.	OGS	$2.68	$76.30	4.50%	4.59%	4.67%	4.76%	4.85%	4.93%	5.02%	5.11%	5.19%	5.28%	5.37%	5.45%	8.83%
Southwest Gas Corporation	SWX	$2.48	$78.30	10.00%	9.59%	9.17%	8.76%	8.35%	7.93%	7.52%	7.11%	6.69%	6.28%	5.87%	5.45%	10.84%
Mean				7.03%	6.89%	6.74%	6.60%	6.46%	6.31%	6.17%	6.03%	5.88%	5.74%	5.60%	5.45%	9.52%
Median				7.00%	6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	9.22%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$158.64	7.00%	6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	8.23%
NiSource Inc.	NI	$1.12	$40.71	7.90%	7.68%	7.46%	7.23%	7.01%	6.79%	6.57%	6.34%	6.12%	5.90%	5.68%	5.45%	9.29%
Northwest Natural Gas Company	NWN	$1.96	$40.87	5.75%	5.72%	5.70%	5.67%	5.64%	5.62%	5.59%	5.56%	5.54%	5.51%	5.48%	5.45%	10.78%
ONE Gas Inc.	OGS	$2.68	$74.02	4.50%	4.59%	4.67%	4.76%	4.85%	4.93%	5.02%	5.11%	5.19%	5.28%	5.37%	5.45%	8.94%
Southwest Gas Corporation	SWX	$2.48	$76.00	10.00%	9.59%	9.17%	8.76%	8.35%	7.93%	7.52%	7.11%	6.69%	6.28%	5.87%	5.45%	10.98%
Mean				7.03%	6.89%	6.74%	6.60%	6.46%	6.31%	6.17%	6.03%	5.88%	5.74%	5.60%	5.45%	9.65%
Median				7.00%	6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	9.29%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 90-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$153.71	7.00%	6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	8.32%
NiSource Inc.	NI	$1.12	$39.53	7.90%	7.68%	7.46%	7.23%	7.01%	6.79%	6.57%	6.34%	6.12%	5.90%	5.68%	5.45%	9.40%
Northwest Natural Gas Company	NWN	$1.96	$40.72	5.75%	5.72%	5.70%	5.67%	5.64%	5.62%	5.59%	5.56%	5.54%	5.51%	5.48%	5.45%	10.80%
ONE Gas Inc.	OGS	$2.68	$73.30	4.50%	4.59%	4.67%	4.76%	4.85%	4.93%	5.02%	5.11%	5.19%	5.28%	5.37%	5.45%	8.98%
Southwest Gas Corporation	SWX	$2.48	$74.00	10.00%	9.59%	9.17%	8.76%	8.35%	7.93%	7.52%	7.11%	6.69%	6.28%	5.87%	5.45%	11.12%
Mean					6.89%	6.74%	6.60%	6.46%	6.31%	6.17%	6.03%	5.88%	5.74%	5.60%	5.45%	9.72%
Median					6.86%	6.72%	6.58%	6.44%	6.30%	6.16%	6.02%	5.88%	5.74%	5.60%	5.45%	9.40%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 180-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$165.62	7.17%	7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	8.17%
NiSource Inc.	NI	$1.12	$41.53	8.61%	8.33%	8.04%	7.75%	7.47%	7.18%	6.89%	6.60%	6.32%	6.03%	5.74%	5.45%	9.51%
Northwest Natural Gas Company	NWN	$1.96	$42.14	6.13%	6.06%	6.00%	5.94%	5.88%	5.82%	5.76%	5.70%	5.64%	5.58%	5.52%	5.45%	10.82%
ONE Gas Inc.	OGS	$2.68	$76.30	5.35%	5.36%	5.37%	5.38%	5.39%	5.40%	5.41%	5.42%	5.43%	5.43%	5.44%	5.45%	9.17%
Southwest Gas Corporation	SWX	$2.48	$78.30	11.17%	10.65%	10.13%	9.61%	9.09%	8.57%	8.05%	7.53%	7.01%	6.49%	5.97%	5.45%	11.43%
Mean				7.69%	7.48%	7.28%	7.08%	6.87%	6.67%	6.47%	6.27%	6.06%	5.86%	5.66%	5.45%	9.82%
Median				7.17%	7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	9.51%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$158.64	7.17%	7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	8.29%
NiSource Inc.	NI	$1.12	$40.71	8.61%	8.33%	8.04%	7.75%	7.47%	7.18%	6.89%	6.60%	6.32%	6.03%	5.74%	5.45%	9.58%
Northwest Natural Gas Company	NWN	$1.96	$40.87	6.13%	6.06%	6.00%	5.94%	5.88%	5.82%	5.76%	5.70%	5.64%	5.58%	5.52%	5.45%	10.98%
ONE Gas Inc.	OGS	$2.68	$74.02	5.35%	5.36%	5.37%	5.38%	5.39%	5.40%	5.41%	5.42%	5.43%	5.43%	5.44%	5.45%	9.29%
Southwest Gas Corporation	SWX	$2.48	$76.00	11.17%	10.65%	10.13%	9.61%	9.09%	8.57%	8.05%	7.53%	7.01%	6.49%	5.97%	5.45%	11.59%
Mean				7.69%	7.48%	7.28%	7.08%	6.87%	6.67%	6.47%	6.27%	6.06%	5.86%	5.66%	5.45%	9.95%
Median				7.17%	7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	9.58%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 90-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$153.71	7.17%	7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	8.38%
NiSource Inc.	NI	$1.12	$39.53	8.61%	8.33%	8.04%	7.75%	7.47%	7.18%	6.89%	6.60%	6.32%	6.03%	5.74%	5.45%	9.70%
Northwest Natural Gas Company	NWN	$1.96	$40.72	6.13%	6.06%	6.00%	5.94%	5.88%	5.82%	5.76%	5.70%	5.64%	5.58%	5.52%	5.45%	11.00%
ONE Gas Inc.	OGS	$2.68	$73.30	5.35%	5.36%	5.37%	5.38%	5.39%	5.40%	5.41%	5.42%	5.43%	5.43%	5.44%	5.45%	9.33%
Southwest Gas Corporation	SWX	$2.48	$74.00	11.17%	10.65%	10.13%	9.61%	9.09%	8.57%	8.05%	7.53%	7.01%	6.49%	5.97%	5.45%	11.74%
Mean					7.48%	7.28%	7.08%	6.87%	6.67%	6.47%	6.27%	6.06%	5.86%	5.66%	5.45%	10.03%
Median					7.02%	6.86%	6.71%	6.55%	6.39%	6.24%	6.08%	5.92%	5.77%	5.61%	5.45%	9.70%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 180-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$165.62	7.30%	7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	8.21%
NiSource Inc.	NI	$1.12	$41.53	9.50%	9.13%	8.76%	8.40%	8.03%	7.66%	7.29%	6.93%	6.56%	6.19%	5.82%	5.45%	9.88%
Northwest Natural Gas Company	NWN	$1.96	$42.14	6.50%	6.40%	6.31%	6.21%	6.12%	6.02%	5.93%	5.83%	5.74%	5.64%	5.55%	5.45%	11.02%
ONE Gas Inc.	OGS	$2.68	$76.30	5.94%	5.89%	5.85%	5.81%	5.76%	5.72%	5.67%	5.63%	5.59%	5.54%	5.50%	5.45%	9.42%
Southwest Gas Corporation	SWX	$2.48	$78.30	13.11%	12.42%	11.72%	11.02%	10.33%	9.63%	8.93%	8.24%	7.54%	6.85%	6.15%	5.45%	12.50%
Mean				8.47%	8.20%	7.92%	7.65%	7.37%	7.10%	6.83%	6.55%	6.28%	6.00%	5.73%	5.45%	10.20%
Median				7.30%	7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	9.88%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 2025
[2] Source: Bloomberg Professional, equals 30-day average as of September 30, 2025
[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$158.64	7.30%	7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	8.33%
NiSource Inc.	NI	$1.12	$40.71	9.50%	9.13%	8.76%	8.40%	8.03%	7.66%	7.29%	6.93%	6.56%	6.19%	5.82%	5.45%	9.97%
Northwest Natural Gas Company	NWN	$1.96	$40.87	6.50%	6.40%	6.31%	6.21%	6.12%	6.02%	5.93%	5.83%	5.74%	5.64%	5.55%	5.45%	11.19%
ONE Gas Inc.	OGS	$2.68	$74.02	5.94%	5.89%	5.85%	5.81%	5.76%	5.72%	5.67%	5.63%	5.59%	5.54%	5.50%	5.45%	9.54%
Southwest Gas Corporation	SWX	$2.48	$76.00	13.11%	12.42%	11.72%	11.02%	10.33%	9.63%	8.93%	8.24%	7.54%	6.85%	6.15%	5.45%	12.67%
Mean				8.47%	8.20%	7.92%	7.65%	7.37%	7.10%	6.83%	6.55%	6.28%	6.00%	5.73%	5.45%	10.34%
Median				7.30%	7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	9.97%

Notes:
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[3] Source: Exhibit CNGC/504
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
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[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
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180-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
					Second Stage Gwth Rate											
Company	Ticker	Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Atmos Energy Corporation	ATO	$3.48	$153.71	7.30%	7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	8.42%
NiSource Inc.	NI	$1.12	$39.53	9.50%	9.13%	8.76%	8.40%	8.03%	7.66%	7.29%	6.93%	6.56%	6.19%	5.82%	5.45%	10.09%
Northwest Natural Gas Company	NWN	$1.96	$40.72	6.50%	6.40%	6.31%	6.21%	6.12%	6.02%	5.93%	5.83%	5.74%	5.64%	5.55%	5.45%	11.21%
ONE Gas Inc.	OGS	$2.68	$73.30	5.94%	5.89%	5.85%	5.81%	5.76%	5.72%	5.67%	5.63%	5.59%	5.54%	5.50%	5.45%	9.58%
Southwest Gas Corporation	SWX	$2.48	$74.00	13.11%	12.42%	11.72%	11.02%	10.33%	9.63%	8.93%	8.24%	7.54%	6.85%	6.15%	5.45%	12.83%
Mean					8.20%	7.92%	7.65%	7.37%	7.10%	6.83%	6.55%	6.28%	6.00%	5.73%	5.45%	10.43%
Median					7.13%	6.96%	6.80%	6.63%	6.46%	6.29%	6.13%	5.96%	5.79%	5.62%	5.45%	10.09%

Notes:
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[4] Equals [3] + ([14] − [3]) / 11
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[7] Equals [6] + ([14] − [3]) / 11
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[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Source: Exhibit CNGC/306
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

LONG-TERM GDP GROWTH RATE

EXHIBIT 506

November 2025

CALCULATION OF LONG-TERM GROWTH RATE FOR MULTI-STAGE DCF

Description	Notes	Year	Amount
Historical GDP Growth			
Real GDP ($ Billions)	[1]	1929	$ 1,191.1
Real GDP ($ Billions)	[1]	2024	$ 23,358.4
Compound Annual Growth Rate			**3.18%**
Projected Inflation			
Consumer Price Index (YoY % Change)	[2]	2032-2036	2.20%
Consumer Price Index (All-Urban)	[3]	2035	3.86
Consumer Price Index (All-Urban)	[3]	2050	5.37
Compound Annual Growth Rate			2.23%
GDP Chain-type Price Index (2012=1.000)	[3]	2035	1.66
GDP Chain-type Price Index (2012=1.000)	[3]	2050	2.30
Compound Annual Growth Rate			2.18%
Average Inflation Forecast	[4]		**2.20%**
Long-Term GDP Growth Rate	[5]		**5.45%**

Notes:
[1] Bureau of Economic Analysis, September 25, 2025
[2] Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[3] Energy Information Administration, Annual Energy Outlook 2025 at Table 20, April 15, 2025
[4] Average of 3 inflation sources
[5] Equals (1+3.18%) x (1+2.20%)-1

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CAPM/ECAPM

EXHIBIT 507

November 2025

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
NiSource Inc.	NI	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
Northwest Natural Gas Company	NWN	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
ONE Gas Inc.	OGS	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Southwest Gas Corporation	SWX	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Mean						11.29%	11.80%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 202:
[2] Source: Value Line
[3] Source: Exhibit CNGC/509
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
NiSource Inc.	NI	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
Northwest Natural Gas Company	NWN	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
ONE Gas Inc.	OGS	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Southwest Gas Corporation	SWX	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Mean						11.25%	11.77%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Source: Value Line
[3] Source: Exhibit CNGC/509
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
NiSource Inc.	NI	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
Northwest Natural Gas Company	NWN	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
ONE Gas Inc.	OGS	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Southwest Gas Corporation	SWX	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Mean						11.20%	11.73%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[2] Source: Value Line
[3] Source: Exhibit CNGC/509
[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

		[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)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.79%	0.76	13.34%	8.55%	11.31%	11.82%
NiSource Inc.	NI	4.79%	0.78	13.34%	8.55%	11.42%	11.90%
Northwest Natural Gas Company	NWN	4.79%	0.73	13.34%	8.55%	10.99%	11.58%
ONE Gas Inc.	OGS	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Southwest Gas Corporation	SWX	4.79%	0.84	13.34%	8.55%	11.95%	12.30%
Mean						11.38%	11.87%

Notes:
[1] Source: Bloomberg Professional, as of September 30, 202
[2] Source: Exhibit CNGC/508
[3] Source: Exhibit CNGC/509
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.62%	0.76	13.34%	8.72%	11.27%	11.79%
NiSource Inc.	NI	4.62%	0.78	13.34%	8.72%	11.38%	11.87%
Northwest Natural Gas Company	NWN	4.62%	0.73	13.34%	8.72%	10.94%	11.54%
ONE Gas Inc.	OGS	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Southwest Gas Corporation	SWX	4.62%	0.84	13.34%	8.72%	11.92%	12.28%
Mean						11.34%	11.84%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Source: Exhibit CNGC/508
[3] Source: Exhibit CNGC/509
[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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.40%	0.76	13.34%	8.94%	11.22%	11.75%
NiSource Inc.	NI	4.40%	0.78	13.34%	8.94%	11.33%	11.83%
Northwest Natural Gas Company	NWN	4.40%	0.73	13.34%	8.94%	10.88%	11.50%
ONE Gas Inc.	OGS	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Southwest Gas Corporation	SWX	4.40%	0.84	13.34%	8.94%	11.89%	12.25%
Mean						11.29%	11.80%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[2] Source: Exhibit CNGC/508
[3] Source: Exhibit CNGC/509
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

LONG-TERM BETA ANALYSIS

EXHIBIT 508

November 2025

HISTORICAL BETA - 2013 - 2024

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] 12/31/2023	[12] 12/31/2024	[13] Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.90	0.76
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.95	0.78
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.90	0.73
ONE Gas, Inc.	OGS				0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.85	0.75
Southwest Gas Corporation	SWX	0.80	0.85	0.80	0.75	0.80	0.70	0.70	0.95	0.95	0.90	0.90	0.95	0.84
Mean		0.78	0.80	0.75	0.70	0.70	0.61	0.62	0.84	0.85	0.83	0.85	0.91	0.77

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

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

MARKET RETURN

EXHIBIT 509

November 2025

MARKET RETURN DERIVED FROM S&P 500 INDEX

[1] Estimated Weighted Average Dividend Yield	1.31%
[2] Estimated Weighted Average Long-Term Growth Rate	11.95%
[3] S&P 500 Estimated Required Market Return	13.34%

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 Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	321.65	49.04	15,773.64		11.17%		-9.85%	
American Express Co	AXP	695.88	332.16	231,144.24	0.56%	0.99%	0.01%	15.03%	0.08%
Verizon Communications Inc	VZ	4,216.32	43.95	185,307.48	0.45%	6.28%	0.03%	2.27%	0.01%
Texas Pacific Land Corp	TPL	22.98	933.64	21,454.50		0.69%			
Broadcom Inc	AVGO	4,722.37	329.91	1,557,955.44		0.72%		40.05%	
Boeing Co/The	BA	756.16	215.83	163,201.52				31.71%	
Solventum Corp	SOLV	173.39	73.00	12,657.31	0.03%			1.28%	0.00%
Caterpillar Inc	CAT	468.48	477.15	223,534.72	0.54%	1.27%	0.01%	6.56%	0.04%
JPMorgan Chase & Co	JPM	2,749.75	315.43	867,354.86	2.11%	1.90%	0.04%	8.55%	0.18%
Chevron Corp	CVX	2,047.39	155.29	317,939.80	0.77%	4.40%	0.03%	15.39%	0.12%
Coca-Cola Co/The	KO	4,303.67	66.32	285,419.21	0.69%	3.08%	0.02%	5.90%	0.04%
AbbVie Inc	ABBV	1,766.56	231.54	409,028.90	0.99%	2.83%	0.03%	13.98%	0.14%
Walt Disney Co/The	DIS	1,797.93	114.50	205,863.42	0.50%	0.87%	0.00%	13.12%	0.07%
Corpay Inc	CPAY	70.61	288.06	20,341.18	0.05%			12.12%	0.01%
Extra Space Storage Inc	EXR	212.25	140.94	29,915.02	0.07%	4.60%	0.00%	3.14%	0.00%
Exxon Mobil Corp	XOM	4,263.25	112.75	480,681.10	1.17%	3.51%	0.04%	11.40%	0.13%
Phillips 66	PSX	404.12	136.02	54,968.98		3.53%		22.37%	
General Electric Co	GE	1,060.44	300.82	319,001.38		0.48%		20.51%	
HP Inc	HPQ	934.70	27.23	25,451.93		4.25%		-0.60%	
Home Depot Inc/The	HD	995.39	405.19	403,320.72	0.98%	2.27%	0.02%	5.04%	0.05%
Monolithic Power Systems Inc	MPWR	47.89	920.64	44,091.29		0.68%			
International Business Machines Corp	IBM	931.52	282.16	262,837.47	0.64%	2.38%	0.02%	6.68%	0.04%
Johnson & Johnson	JNJ	2,408.34	185.42	446,554.19	1.09%	2.80%	0.03%	7.35%	0.08%
Lululemon Athletica Inc	LULU	113.47	177.93	20,189.38	0.05%			1.24%	0.00%
McDonald's Corp	MCD	713.60	303.89	216,857.25	0.53%	2.33%	0.01%	8.63%	0.05%
Merck & Co Inc	MRK	2,497.78	83.93	209,638.94	0.51%	3.86%	0.02%	15.57%	0.08%
3M Co	MMM	532.63	155.18	82,653.48	0.20%	1.88%	0.00%	6.99%	0.01%
American Water Works Co Inc	AWK	203.20	139.19	28,283.01	0.07%	2.38%	0.00%	6.60%	0.00%
Bank of America Corp	BAC	7,406.95	51.59	382,124.41		2.17%			
Pfizer Inc	PFE	5,685.55	25.48	144,867.83	0.35%	6.75%	0.02%	0.11%	0.00%
Procter & Gamble Co/The	PG	2,340.49	153.65	359,615.56	0.87%	2.75%	0.02%	4.08%	0.04%
AT&T Inc	T	7,150.39	28.24	201,926.89	0.49%	3.93%	0.02%	4.63%	0.02%
Travelers Cos Inc/The	TRV	225.13	279.22	62,861.87		1.58%		54.50%	
RTX Corp	RTX	1,338.54	167.33	223,978.20	0.54%	1.63%	0.01%	7.41%	0.04%
Analog Devices Inc	ADI	491.96	245.70	120,873.45	0.29%	1.61%	0.00%	17.18%	0.05%
Walmart Inc	WMT	7,972.85	103.06	821,682.04	2.00%	0.91%	0.02%	8.46%	0.17%
Cisco Systems Inc	CSCO	3,953.20	68.42	270,477.74	0.66%	2.40%	0.02%	8.32%	0.05%
Intel Corp	INTC	4,651.58	33.55	156,060.61	0.38%			9.28%	0.04%
General Motors Co	GM	952.08	60.97	58,048.18	0.14%	0.98%	0.00%	6.04%	0.01%
Microsoft Corp	MSFT	7,433.17	517.95	3,850,008.53	9.36%	0.70%	0.07%	14.84%	1.39%
Dollar General Corp	DG	220.11	103.35	22,747.96	0.06%	2.28%	0.00%	5.24%	0.00%
Cigna Group/The	CI	266.93	288.25	76,942.02	0.19%	2.10%	0.00%	10.86%	0.02%
Kinder Morgan Inc	KMI	2,222.08	28.31	62,907.02	0.15%	4.13%	0.01%	8.46%	0.01%
Citigroup Inc	C	1,840.90	101.50	186,851.14		2.36%		25.65%	
American International Group Inc	AIG	554.00	78.54	43,511.46	0.11%	2.29%	0.00%	19.99%	0.02%
Altria Group Inc	MO	1,679.89	66.06	110,973.60	0.27%	6.42%	0.02%	4.72%	0.01%
HCA Healthcare Inc	HCA	233.99	426.20	99,728.03	0.24%	0.68%	0.00%	10.76%	0.03%
International Paper Co	IP	527.98	46.40	24,498.37		3.99%		54.45%	
Hewlett Packard Enterprise Co	HPE	1,319.45	24.56	32,405.69	0.08%	2.12%	0.00%	7.61%	0.01%
Abbott Laboratories	ABT	1,740.46	133.94	233,117.08	0.57%	1.76%	0.01%	9.97%	0.06%
Aflac Inc	AFL	534.83	111.70	59,740.68		2.08%		25.77%	
Air Products and Chemicals Inc	APD	222.55	270.93	60,296.44	0.15%	2.64%	0.00%	3.42%	0.01%
Super Micro Computer Inc	SMCI	594.27	47.94	28,489.46	0.07%			19.06%	0.01%
Royal Caribbean Cruises Ltd	RCL	271.63	323.58	87,893.28		1.24%		22.77%	
Interactive Brokers Group Inc	IBKR	445.25	68.81	30,637.44	0.07%	0.47%	0.00%	12.54%	0.01%
Lennox International Inc	LII	35.12	529.36	18,593.39		0.98%			
Archer-Daniels-Midland Co	ADM	480.46	59.74	28,702.95	0.07%	3.41%	0.00%	4.70%	0.00%
EMCOR Group Inc	EME	44.76	649.54	29,076.17		0.15%			
Automatic Data Processing Inc	ADP	405.09	293.50	118,893.77		2.10%			
Verisk Analytics Inc	VRSK	139.71	251.51	35,139.71		0.72%			
AutoZone Inc	AZO	16.73	4,290.24	71,770.18	0.17%			13.66%	0.02%
Linde PLC	LIN	468.91	475.00	222,732.03	0.54%	1.26%	0.01%	8.66%	0.05%
Avery Dennison Corp	AVY	77.98	162.17	12,646.27	0.03%	2.32%	0.00%	6.84%	0.00%
MSCI Inc	MSCI	77.37	567.41	43,897.81		1.27%			
Ball Corp	BALL	272.15	50.42	13,721.75	0.03%	1.59%	0.00%	12.27%	0.00%
Axon Enterprise Inc	AXON	78.50	717.64	56,337.93				28.56%	
Dayforce Inc	DAY	158.01	68.89	10,885.07					
Carrier Global Corp	CARR	851.02	59.70	50,806.06	0.12%	1.51%	0.00%	11.41%	0.01%
Bank of New York Mellon Corp/The	BK	705.24	108.96	76,843.04	0.19%	1.95%	0.00%	14.85%	0.03%
Otis Worldwide Corp	OTIS	392.48	91.43	35,884.01		1.84%			
Baxter International Inc	BAX	513.62	22.77	11,695.15	0.03%	2.99%	0.00%	12.49%	0.00%
Becton Dickinson & Co	BDX	286.63	187.17	53,648.06	0.13%	2.22%	0.00%	7.29%	0.01%
Berkshire Hathaway Inc	BRK/B	1,378.55	502.74	693,050.04					
Best Buy Co Inc	BBY	210.10	75.62	15,887.86	0.04%	5.03%	0.00%	4.17%	0.00%
Boston Scientific Corp	BSX	1,481.75	97.63	144,663.41	0.35%			14.86%	0.05%
Bristol-Myers Squibb Co	BMY	2,035.44	45.10	91,798.16		5.50%		82.51%	
Brown-Forman Corp	BF/B	303.61	27.08	8,221.73	0.02%	3.35%	0.00%	2.43%	0.00%
Coterra Energy Inc	CTRA	763.14	23.65	18,048.26		3.72%		30.08%	
Hilton Worldwide Holdings Inc	HLT	235.19	259.44	61,018.67	0.15%	0.23%	0.00%	12.75%	0.02%
Carnival Corp	CCL	1,167.54	28.91	33,753.61				21.87%	
Builders FirstSource Inc	BLDR	110.55	121.25	13,403.82				-4.21%	
UDR Inc	UDR	331.35	37.26	12,346.00	0.03%	4.62%	0.00%	1.33%	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 Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Clorox Co/The	CLX	122.31	123.30	15,080.75	0.04%	4.02%	0.00%	0.34%	0.00%
Paycom Software Inc	PAYC	57.88	208.14	12,046.48	0.03%	0.72%	0.00%	9.16%	0.00%
CMS Energy Corp	CMS	299.34	73.26	21,929.32	0.05%	2.96%	0.00%	7.51%	0.00%
Colgate-Palmolive Co	CL	808.22	79.94	64,609.17	0.16%	2.60%	0.00%	4.85%	0.01%
EPAM Systems Inc	EPAM	55.70	150.79	8,398.54					
Conagra Brands Inc	CAG	479.05	18.31	8,771.40		7.65%		-7.51%	
Airbnb Inc	ABNB	429.08	121.42	52,098.84	0.13%			10.47%	0.01%
Consolidated Edison Inc	ED	360.65	100.52	36,252.71	0.09%	3.38%	0.00%	5.20%	0.00%
Corning Inc	GLW	856.62	82.03	70,268.43	0.17%	1.37%	0.00%	18.16%	0.03%
GoDaddy Inc	GDDY	138.45	136.83	18,943.98					
Cummins Inc	CMI	137.79	422.37	58,196.69	0.14%	1.89%	0.00%	10.71%	0.02%
Danaher Corp	DHR	716.05	198.26	141,964.39	0.35%	0.65%	0.00%	8.10%	0.03%
Target Corp	TGT	454.40	89.70	40,759.60		5.08%		-1.37%	
Williams-Sonoma Inc	WSM	121.79	195.45	23,803.92	0.06%	1.35%	0.00%	4.68%	0.00%
Deere & Co	DE	270.33	457.26	123,610.82		1.42%		-2.85%	
Dominion Energy Inc	D	853.43	61.17	52,204.54		4.36%		23.10%	
Trade Desk Inc/The	TTD	445.67	49.01	21,842.14	0.05%			15.53%	0.01%
Dover Corp	DOV	137.13	166.83	22,878.14	0.06%	1.25%	0.00%	11.53%	0.01%
Alliant Energy Corp	LNT	256.97	67.41	17,322.30	0.04%	3.01%	0.00%	6.09%	0.00%
Steel Dynamics Inc	STLD	147.20	139.43	20,524.74	0.05%	1.43%	0.00%	13.77%	0.01%
Duke Energy Corp	DUK	777.02	123.75	96,156.43	0.23%	3.44%	0.01%	7.44%	0.02%
Regency Centers Corp	REG	181.55	72.90	13,235.24	0.03%	3.87%	0.00%	5.02%	0.00%
Eaton Corp PLC	ETN	389.30	374.25	145,695.53	0.35%	1.11%	0.00%	13.81%	0.05%
Ecolab Inc	ECL	283.62	273.86	77,673.52	0.19%	0.95%	0.00%	13.00%	0.02%
Revvity Inc	RVTY	116.07	87.65	10,173.76	0.02%	0.32%	0.00%	6.16%	0.00%
Dell Technologies Inc	DELL	336.90	141.77	47,762.97	0.12%	1.48%	0.00%	16.92%	0.02%
Emerson Electric Co	EMR	562.80	131.18	73,828.10	0.18%	1.61%	0.00%	10.06%	0.02%
EOG Resources Inc	EOG	545.99	112.12	61,216.78		3.64%			
Aon PLC	AON	215.63	356.58	76,888.13	0.19%	0.84%	0.00%	10.12%	0.02%
Entergy Corp	ETR	446.41	93.19	41,600.86	0.10%	2.58%	0.00%	5.80%	0.01%
Equifax Inc	EFX	123.80	256.53	31,757.74	0.08%	0.78%	0.00%	10.18%	0.01%
EQT Corp	EQT	624.06	54.43	33,967.83		1.16%		41.56%	
IQVIA Holdings Inc	IQV	170.00	189.94	32,289.80	0.08%			8.97%	0.01%
Gartner Inc	IT	75.74	262.87	19,908.67					
FedEx Corp	FDX	235.96	235.81	55,640.66	0.14%	2.46%	0.00%	9.05%	0.01%
Brown & Brown Inc	BRO	329.84	93.79	30,935.96	0.08%	0.64%	0.00%	11.27%	0.01%
Ford Motor Co	F	3,909.01	11.96	46,751.74		5.02%		-1.10%	
NextEra Energy Inc	NEE	2,059.29	75.49	155,456.00	0.38%	3.00%	0.01%	7.39%	0.03%
Franklin Resources Inc	BEN	519.20	23.13	12,008.99		5.53%		-0.14%	
Garmin Ltd	GRMN	192.49	246.22	47,395.86	0.12%	1.46%	0.00%	11.16%	0.01%
Freeport-McMoRan Inc	FCX	1,435.77	39.22	56,311.06		1.53%		24.99%	
Expand Energy Corp	EXE	238.15	106.24	25,300.60		5.52%			
Dexcom Inc	DXCM	392.16	67.29	26,388.13				23.31%	
General Dynamics Corp	GD	268.99	341.00	91,726.73	0.22%	1.76%	0.00%	14.95%	0.03%
General Mills Inc	GIS	533.42	50.42	26,894.86		4.84%		-2.94%	
Genuine Parts Co	GPC	139.09	138.60	19,278.19		2.97%			
Atmos Energy Corp	ATO	160.52	170.75	27,409.40		2.04%			
WW Grainger Inc	GWW	47.83	952.96	45,582.21	0.11%	0.95%	0.00%	4.41%	0.00%
Halliburton Co	HAL	852.60	24.60	20,974.01		2.76%			
L3Harris Technologies Inc	LHX	187.09	305.41	57,140.62	0.14%	1.57%	0.00%	12.88%	0.02%
Healthpeak Properties Inc	DOC	694.92	19.15	13,307.78	0.03%	6.37%	0.00%	4.24%	0.00%
Insulet Corp	PODD	70.39	308.73	21,732.29				25.99%	
Fortive Corp	FTV	338.34	48.99	16,575.10		0.49%			
Hershey Co/The	HSY	148.11	187.05	27,704.11		2.93%		-8.41%	
Synchrony Financial	SYF	372.06	71.05	26,434.69	0.06%	1.69%	0.00%	16.89%	0.01%
Hormel Foods Corp	HRL	550.00	24.74	13,606.96		4.69%			
Arthur J Gallagher & Co	AJG	256.40	309.74	79,417.34		0.84%			
Mondelez International Inc	MDLZ	1,293.95	62.47	80,832.77	0.20%	3.20%	0.01%	1.85%	0.00%
CenterPoint Energy Inc	CNP	652.73	38.80	25,325.86	0.06%	2.27%	0.00%	8.98%	0.01%
Humana Inc	HUM	120.27	260.17	31,291.12	0.08%	1.36%	0.00%	14.02%	0.01%
Willis Towers Watson PLC	WTW	97.55	345.45	33,697.95	0.08%	1.07%	0.00%	7.47%	0.01%
Illinois Tool Works Inc	ITW	291.50	260.76	76,011.54	0.18%	2.47%	0.00%	1.93%	0.00%
CDW Corp/DE	CDW	131.06	159.28	20,875.36	0.05%	1.57%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	222.52	421.96	93,892.58	0.23%	0.89%	0.00%	11.32%	0.03%
Interpublic Group of Cos Inc/The	IPG	366.27	27.91	10,222.49	0.02%	4.73%	0.00%	9.40%	0.00%
International Flavors & Fragrances Inc	IFF	256.29	61.54	15,771.91	0.04%	2.60%	0.00%	2.12%	0.00%
Generac Holdings Inc	GNRC	58.68	167.40	9,822.35				20.91%	
NXP Semiconductors NV	NXPI	252.11	227.73	57,414.06	0.14%	1.78%	0.00%	5.71%	0.01%
Kellanova	K	347.67	82.02	28,515.83	0.07%	2.83%	0.00%	1.79%	0.00%
Broadridge Financial Solutions Inc	BR	117.13	238.17	27,896.69		1.64%			
Kimco Realty Corp	KIM	679.50	21.85	14,847.05	0.04%	4.58%	0.00%	3.88%	0.00%
Oracle Corp	ORCL	2,850.79	281.24	801,756.91	1.95%	0.71%	0.01%	18.09%	0.35%
Kroger Co/The	KR	662.68	67.41	44,671.14	0.11%	2.08%	0.00%	6.37%	0.01%
Lennar Corp	LEN	227.60	126.04	28,686.91		1.59%		-9.37%	
Eli Lilly & Co	LLY	946.46	763.00	722,146.51	1.76%	0.79%	0.01%	18.00%	0.32%
Charter Communications Inc	CHTR	136.59	275.11	37,576.86	0.09%			10.93%	0.01%
Loews Corp	L	207.43	100.39	20,823.54		0.25%			
Lowe's Cos Inc	LOW	560.82	251.31	140,940.91	0.34%	1.91%	0.01%	6.54%	0.02%
Hubbell Inc	HUBB	53.14	430.31	22,866.68		1.23%			
IDEX Corp	IEX	75.29	162.76	12,253.76		1.74%			
Marsh & McLennan Cos Inc	MMC	491.62	201.53	99,076.99	0.24%	1.79%	0.00%	8.31%	0.02%
Masco Corp	MAS	209.36	70.39	14,737.11	0.04%	1.76%	0.00%	6.47%	0.00%
S&P Global Inc	SPGI	312.50	486.71	152,096.88		0.79%			
Medtronic PLC	MDT	1,282.69	95.24	122,163.00	0.30%	2.98%	0.01%	5.90%	0.02%
Viatris Inc	VTRS	1,165.87	9.90	11,542.13		4.85%		-2.32%	
CVS Health Corp	CVS	1,268.33	75.39	95,619.13	0.23%	3.53%	0.01%	6.43%	0.01%
DuPont de Nemours Inc	DD	418.72	77.90	32,618.03	0.08%	2.11%	0.00%	6.31%	0.01%
Micron Technology Inc	MU	1,119.13	167.32	187,252.01		0.27%		28.55%	
Motorola Solutions Inc	MSI	166.60	457.29	76,186.29	0.19%	0.95%	0.00%	8.26%	0.02%
Cboe Global Markets Inc	CBOE	104.59	245.25	25,650.73	0.06%	1.17%	0.00%	13.77%	0.01%
Newmont Corp	NEM	1,098.45	84.31	92,610.30	0.23%	1.19%	0.00%	16.41%	0.04%
NIKE Inc	NKE	1,188.02	69.73	82,840.34	0.20%	2.29%	0.00%	19.22%	0.04%
NiSource Inc	NI	470.86	43.30	20,388.02		2.59%			

		[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 Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Norfolk Southern Corp	NSC	224.61	300.41	67,476.56		1.80%			
Principal Financial Group Inc	PFG	222.77	82.91	18,469.73	0.04%	3.76%	0.00%	12.73%	0.01%
Eversource Energy	ES	371.12	71.14	26,401.13	0.06%	4.23%	0.00%	4.40%	0.00%
Northrop Grumman Corp	NOC	143.18	609.32	87,244.25	0.21%	1.52%	0.00%	4.95%	0.01%
Wells Fargo & Co	WFC	3,203.44	83.82	268,512.44	0.65%	2.15%	0.01%	14.00%	0.09%
Nucor Corp	NUE	229.54	135.43	31,085.99	0.08%	1.62%	0.00%	18.58%	0.01%
Occidental Petroleum Corp	OXY	984.44	47.25	46,514.78		2.03%			
Omnicom Group Inc	OMC	193.72	81.53	15,794.23	0.04%	3.43%	0.00%	7.99%	0.00%
ONEOK Inc	OKE	629.76	72.97	45,953.29	0.11%	5.65%	0.01%	8.97%	0.01%
Raymond James Financial Inc	RJF	199.38	172.10	34,313.98	0.08%	1.16%	0.00%	11.82%	0.01%
PG&E Corp	PCG	2,197.84	15.08	33,143.39	0.08%	0.66%	0.00%	8.91%	0.01%
Parker-Hannifin Corp	PH	126.54	758.15	95,939.39	0.23%	0.95%	0.00%	7.61%	0.02%
Rollins Inc	ROL	484.64	58.74	28,467.75		1.12%			
PPL Corp	PPL	739.52	37.16	27,480.39	0.07%	2.93%	0.00%	7.34%	0.00%
Aptiv PLC	APTV	217.76	86.22	18,775.25	0.05%			16.62%	0.01%
ConocoPhillips	COP	1,248.94	94.59	118,137.45		3.30%			
PulteGroup Inc	PHM	197.30	132.13	26,068.93		0.67%		-2.19%	
Pinnacle West Capital Corp	PNW	119.43	89.66	10,707.85		3.99%			
PNC Financial Services Group Inc/The	PNC	393.81	200.93	79,127.72	0.19%	3.38%	0.01%	10.42%	0.02%
PPG Industries Inc	PPG	225.70	105.11	23,723.33	0.06%	2.70%	0.00%	6.81%	0.00%
DoorDash Inc	DASH	398.68	271.99	108,437.11					
Progressive Corp/The	PGR	586.21	246.95	144,764.19		0.16%		50.71%	
Veralto Corp	VLTO	248.16	106.61	26,456.43		0.41%			
Public Service Enterprise Group Inc	PEG	499.08	83.46	41,653.20	0.10%	3.02%	0.00%	8.76%	0.01%
Cooper Cos Inc/The	COO	198.81	68.56	13,630.34	0.03%			9.31%	0.00%
Edison International	EIX	384.83	55.28	21,273.62	0.05%	5.99%	0.00%	9.60%	0.00%
Schlumberger NV	SLB	1,493.88	34.37	51,344.62		3.32%		-4.18%	
Charles Schwab Corp/The	SCHW	1,815.22	95.47	173,298.99	0.42%	1.13%	0.00%	19.98%	0.08%
Sherwin-Williams Co/The	SHW	249.33	346.26	86,334.16	0.21%	0.91%	0.00%	6.92%	0.01%
West Pharmaceutical Services Inc	WST	71.91	262.33	18,863.45	0.05%	0.34%	0.00%	8.04%	0.00%
J M Smucker Co/The	SJM	106.69	108.60	11,586.01	0.03%	4.05%	0.00%	1.56%	0.00%
Snap-on Inc	SNA	52.16	346.53	18,076.17	0.04%	2.47%	0.00%	4.10%	0.00%
AMETEK Inc	AME	230.95	188.00	43,419.34	0.11%	0.66%	0.00%	9.13%	0.01%
Uber Technologies Inc	UBER	2,085.42	97.97	204,308.47				-3.85%	
Southern Co/The	SO	1,100.19	94.77	104,265.35	0.25%	3.12%	0.01%	6.75%	0.02%
Truist Financial Corp	TFC	1,289.44	45.72	58,952.98	0.14%	4.55%	0.01%	9.19%	0.01%
Southwest Airlines Co	LUV	525.19	31.91	16,758.74		2.26%		58.26%	
W R Berkley Corp	WRB	379.29	76.62	29,061.41	0.07%	0.47%	0.00%	6.85%	0.00%
Stanley Black & Decker Inc	SWK	154.79	74.33	11,505.71		4.47%			
Public Storage	PSA	175.45	288.85	50,679.56	0.12%	4.15%	0.01%	2.40%	0.00%
Arista Networks Inc	ANET	1,256.87	145.71	183,137.85	0.45%			18.74%	0.08%
Sysco Corp	SYY	478.21	82.34	39,376.01		2.62%			
Corteva Inc	CTVA	683.01	67.63	46,192.28	0.11%	1.06%	0.00%	16.37%	0.02%
Texas Instruments Inc	TXN	909.14	183.73	167,035.77	0.41%	3.09%	0.01%	11.04%	0.04%
Textron Inc	TXT	178.21	84.49	15,056.57	0.04%	0.09%	0.00%	10.03%	0.00%
Thermo Fisher Scientific Inc	TMO	377.61	485.02	183,149.43	0.45%	0.35%	0.00%	7.56%	0.03%
TJX Cos Inc/The	TJX	1,112.94	144.54	160,864.17	0.39%	1.18%	0.00%	8.43%	0.03%
Globe Life Inc	GL	81.00	142.97	11,581.08		0.76%			
Johnson Controls International plc	JCI	654.39	109.95	71,949.68	0.17%	1.46%	0.00%	15.92%	0.03%
Ulta Beauty Inc	ULTA	44.84	546.75	24,515.37	0.06%			4.39%	0.00%
Union Pacific Corp	UNP	593.04	236.37	140,177.73	0.34%	2.34%	0.01%	7.79%	0.03%
Keysight Technologies Inc	KEYS	171.86	174.92	30,061.10	0.07%			12.93%	0.01%
UnitedHealth Group Inc	UNH	905.67	345.30	312,729.10	0.76%	2.56%	0.02%	14.00%	0.11%
Blackstone Inc	BX	737.09	170.85	125,932.11		2.41%		24.34%	
Ventas Inc	VTR	454.47	69.99	31,808.44	0.08%	2.74%	0.00%	9.69%	0.01%
Labcorp Holdings Inc	LH	83.10	287.06	23,854.69	0.06%	1.00%	0.00%	8.77%	0.01%
Vulcan Materials Co	VMC	132.12	307.62	40,644.03	0.10%	0.64%	0.00%	14.51%	0.01%
Weyerhaeuser Co	WY	721.51	24.79	17,886.26		3.39%		-8.95%	
Williams Cos Inc/The	WMB	1,221.18	63.35	77,361.59		3.16%		22.27%	
Constellation Energy Corp	CEG	312.41	329.07	102,803.30	0.25%	0.47%	0.00%	16.22%	0.04%
AppLovin Corp	APP	307.64	718.54	221,049.04				80.10%	
WEC Energy Group Inc	WEC	321.87	114.59	36,882.67	0.09%	3.12%	0.00%	7.65%	0.01%
Adobe Inc	ADBE	418.60	352.75	147,661.15	0.36%			14.13%	0.05%
Vistra Corp	VST	338.82	195.92	66,381.68	0.16%	0.46%	0.00%	10.35%	0.02%
AES Corp/The	AES	712.05	13.16	9,370.57	0.02%	5.35%	0.00%	11.17%	0.00%
Expeditors International of Washington Inc	EXPD	135.72	122.59	16,637.73	0.04%	1.26%	0.00%	4.89%	0.00%
Amgen Inc	AMGN	538.36	282.20	151,925.71	0.37%	3.37%	0.01%	5.37%	0.02%
Apple Inc	AAPL	14,840.39	254.63	3,778,808.51	9.19%	0.41%	0.04%	14.26%	1.31%
Autodesk Inc	ADSK	213.00	317.67	67,663.71	0.16%			15.08%	0.02%
Cintas Corp	CTAS	404.39	205.26	83,005.39		0.88%			
Comcast Corp	CMCSA	3,682.76	31.09	114,497.07	0.28%	4.25%	0.01%	1.88%	0.01%
Molson Coors Beverage Co	TAP	185.39	45.25	8,388.79	0.02%	4.15%	0.00%	0.78%	0.00%
KLA Corp	KLAC	131.68	1,078.60	142,034.93	0.35%	0.70%	0.00%	10.30%	0.04%
Marriott International Inc/MD	MAR	271.46	260.44	70,698.48	0.17%	1.03%	0.00%	10.15%	0.02%
Fiserv Inc	FI	543.59	128.93	70,085.47					
McCormick & Co Inc/MD	MKC	253.04	66.91	16,930.99	0.04%	2.69%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	525.10	98.32	51,628.17		1.34%		-3.95%	
Costco Wholesale Corp	COST	443.48	925.63	410,495.70	1.00%	0.56%	0.01%	6.75%	0.07%
Stryker Corp	SYK	382.31	369.67	141,327.54	0.34%	0.91%	0.00%	10.57%	0.04%
Tyson Foods Inc	TSN	285.76	54.30	15,516.79	0.04%	3.68%	0.00%	18.82%	0.01%
Lamb Weston Holdings Inc	LW	139.35	58.08	8,093.59		2.55%		-2.55%	
Applied Materials Inc	AMAT	796.64	204.74	163,104.57	0.40%	0.90%	0.00%	7.67%	0.03%
Cardinal Health Inc	CAH	237.58	156.45	37,169.64	0.09%	1.31%	0.00%	13.03%	0.01%
Cincinnati Financial Corp	CINF	156.38	158.10	24,723.11	0.06%	2.20%	0.00%	3.48%	0.00%
DR Horton Inc	DHI	298.12	169.47	50,522.99	0.12%	0.94%	0.00%	0.38%	0.00%
Electronic Arts Inc	EA	250.21	201.70	50,466.81	0.12%	0.38%	0.00%	10.70%	0.01%
Erie Indemnity Co	ERIE	46.19	318.16	14,695.51		1.72%			
Fair Isaac Corp	FICO	24.00	1,496.53	35,922.20					
Fastenal Co	FAST	1,147.64	49.04	56,280.10	0.14%	1.79%	0.00%	11.06%	0.02%
M&T Bank Corp	MTB	156.27	197.62	30,881.94	0.08%	3.04%	0.00%	12.35%	0.01%
Xcel Energy Inc	XEL	591.43	80.65	47,698.52	0.12%	2.83%	0.00%	8.88%	0.01%
Fifth Third Bancorp	FITB	661.89	44.55	29,487.08		3.59%			
Gilead Sciences Inc	GILD	1,240.81	111.00	137,729.57		2.85%		29.15%	

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 Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Hasbro Inc	HAS	140.23	75.85	10,636.64	0.03%	3.69%	0.00%	15.87%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,458.80	17.27	25,193.48	0.06%	3.59%	0.00%	14.17%	0.01%
Welltower Inc	WELL	668.83	178.14	119,144.65	0.29%	1.66%	0.00%	17.51%	0.05%
Biogen Inc	BIIB	146.61	140.08	20,537.77	0.05%			0.90%	0.00%
Northern Trust Corp	NTRS	191.23	134.60	25,740.00	0.06%	2.38%	0.00%	9.85%	0.01%
Packaging Corp of America	PKG	89.98	217.93	19,609.08	0.05%	2.29%	0.00%	11.26%	0.01%
Paychex Inc	PAYX	359.89	126.76	45,620.18		3.41%			
QUALCOMM Inc	QCOM	1,079.00	166.36	179,502.44	0.44%	2.14%	0.01%	7.74%	0.03%
Ross Stores Inc	ROST	325.23	152.39	49,561.23	0.12%	1.06%	0.00%	5.82%	0.01%
IDEXX Laboratories Inc	IDXX	80.00	638.89	51,114.20	0.12%			13.50%	0.02%
Starbucks Corp	SBUX	1,136.70	84.60	96,164.82		2.88%		-0.30%	
KeyCorp	KEY	1,096.52	18.69	20,493.88	0.05%	4.39%	0.00%	19.79%	0.01%
Fox Corp	FOXA	210.52	63.06	13,275.36		0.89%		-1.49%	
Fox Corp	FOX	235.58	57.29	13,496.44		0.98%		-1.49%	
State Street Corp	STT	283.70	115.17	32,673.19	0.08%	2.92%	0.00%	12.69%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	455.25	24.63	11,212.83	0.03%			16.72%	0.00%
US Bancorp	USB	1,556.19	48.33	75,210.64	0.18%	4.30%	0.01%	9.63%	0.02%
A O Smith Corp	AOS	114.26	73.41	8,387.79		1.85%			
Gen Digital Inc	GEN	615.87	28.39	17,484.52	0.04%	1.76%	0.00%	13.08%	0.01%
T Rowe Price Group Inc	TROW	219.72	102.64	22,551.57		4.95%		-0.94%	
Waste Management Inc	WM	402.83	220.83	88,957.02	0.22%	1.49%	0.00%	11.23%	0.02%
Constellation Brands Inc	STZ	176.27	134.67	23,737.77		3.03%		-2.05%	
Invesco Ltd	IVZ	445.96	22.94	10,230.41	0.02%	3.66%	0.00%	14.17%	0.00%
Intuit Inc	INTU	278.81	682.91	190,398.72		0.70%			
Morgan Stanley	MS	1,596.34	158.96	253,753.53	0.62%	2.52%	0.02%	10.15%	0.06%
Microchip Technology Inc	MCHP	539.68	64.22	34,658.23		2.83%		29.58%	
Crowdstrike Holdings Inc	CRWD	250.96	490.38	123,063.38	0.30%			17.74%	0.05%
Chubb Ltd	CB	398.69	282.25	112,530.33	0.27%	1.37%	0.00%	4.11%	0.01%
Hologic Inc	HOLX	222.42	67.49	15,011.08	0.04%			7.67%	0.00%
Citizens Financial Group Inc	CFG	431.35	53.16	22,930.51		3.16%		24.02%	
Jabil Inc	JBL	107.32	217.17	23,306.43	0.06%	0.15%	0.00%	13.93%	0.01%
O'Reilly Automotive Inc	ORLY	848.50	107.81	91,476.43	0.22%			10.54%	0.02%
Allstate Corp/The	ALL	263.51	214.65	56,561.42		1.86%		20.50%	
Equity Residential	EQR	381.90	64.73	24,720.26	0.06%	4.28%	0.00%	3.64%	0.00%
Keurig Dr Pepper Inc	KDP	1,358.44	25.51	34,653.68	0.08%	3.61%	0.00%	6.51%	0.01%
Host Hotels & Resorts Inc	HST	687.54	17.02	11,701.98		4.70%		-0.96%	
Incyte Corp	INCY	195.28	84.81	16,561.37				25.00%	
Simon Property Group Inc	SPG	326.48	187.67	61,271.39	0.15%	4.58%	0.01%	1.32%	0.00%
Eastman Chemical Co	EMN	114.83	63.05	7,240.18		5.27%			
AvalonBay Communities Inc	AVB	142.38	193.17	27,504.13	0.07%	3.62%	0.00%	5.18%	0.00%
Prudential Financial Inc	PRU	352.00	103.74	36,516.48	0.09%	5.21%	0.00%	8.23%	0.01%
United Parcel Service Inc	UPS	736.04	83.53	61,481.66		7.85%		-0.74%	
STERIS PLC	STE	98.49	247.44	24,370.52		1.02%			
McKesson Corp	MCK	124.38	772.54	96,091.92	0.23%	0.42%	0.00%	13.50%	0.03%
Lockheed Martin Corp	LMT	233.47	499.21	116,548.09	0.28%	2.64%	0.01%	11.53%	0.03%
Cencora Inc	COR	193.88	312.53	60,592.65	0.15%	0.70%	0.00%	10.33%	0.02%
Capital One Financial Corp	COF	639.52	212.58	135,948.59		1.13%		22.86%	
Campbell's Company/The	CPB	297.99	31.58	9,410.60		4.94%		-2.52%	
Waters Corp	WAT	59.52	299.81	17,845.93	0.04%			9.42%	0.00%
Nordson Corp	NDSN	56.19	226.95	12,751.48		1.45%			
Dollar Tree Inc	DLTR	203.97	94.37	19,248.45	0.05%			9.96%	0.00%
Darden Restaurants Inc	DRI	116.31	190.36	22,141.49	0.05%	3.15%	0.00%	10.59%	0.01%
Evergy Inc	EVRG	229.75	76.02	17,465.29	0.04%	3.51%	0.00%	5.78%	0.00%
Match Group Inc	MTCH	240.62	35.32	8,498.77	0.02%	2.15%	0.00%	16.37%	0.00%
NVR Inc	NVR	2.87	8,034.66	23,057.87	0.06%			1.72%	0.00%
NetApp Inc	NTAP	199.62	118.46	23,646.79	0.06%	1.76%	0.00%	7.34%	0.00%
Old Dominion Freight Line Inc	ODFL	210.17	140.78	29,587.47	0.07%	0.80%	0.00%	5.03%	0.00%
DaVita Inc	DVA	71.50	132.87	9,500.21	0.02%			10.59%	0.00%
Hartford Insurance Group Inc/The	HIG	281.17	133.39	37,505.49	0.09%	1.56%	0.00%	8.89%	0.01%
Iron Mountain Inc	IRM	295.35	101.94	30,107.80		3.08%			
Estee Lauder Cos Inc/The	EL	234.82	88.12	20,691.90		1.59%			
Cadence Design Systems Inc	CDNS	272.49	351.26	95,714.84	0.23%			14.66%	0.03%
Tyler Technologies Inc	TYL	43.26	523.16	22,632.85					
Universal Health Services Inc	UHS	56.39	204.44	11,527.96	0.03%	0.39%	0.00%	10.17%	0.00%
Skyworks Solutions Inc	SWKS	148.43	76.98	11,425.95		3.69%		-9.02%	
Quest Diagnostics Inc	DGX	111.82	190.58	21,311.31	0.05%	1.68%	0.00%	1.06%	0.00%
Rockwell Automation Inc	ROK	112.43	349.53	39,299.20	0.10%	1.50%	0.00%	14.56%	0.01%
Kraft Heinz Co/The	KHC	1,183.60	26.04	30,820.92		6.14%		-4.68%	
American Tower Corp	AMT	468.25	192.32	90,054.08		3.54%		23.73%	
Regeneron Pharmaceuticals Inc	REGN	104.17	562.27	58,571.83	0.14%	0.63%	0.00%	8.03%	0.01%
Amazon.com Inc	AMZN	10,664.91	219.57	2,341,694.75	5.69%			16.62%	0.95%
Jack Henry & Associates Inc	JKHY	72.67	148.93	10,822.03		1.56%			
Ralph Lauren Corp	RL	38.69	313.56	12,132.58	0.03%	1.16%	0.00%	13.40%	0.00%
BXP Inc	BXP	158.38	74.34	11,773.64	0.03%	3.77%	0.00%	1.39%	0.00%
Amphenol Corp	APH	1,220.92	123.75	151,088.99		0.53%		26.21%	
Howmet Aerospace Inc	HWM	403.13	196.23	79,105.48	0.19%	0.24%	0.00%	17.38%	0.03%
Valero Energy Corp	VLO	310.65	170.26	52,891.57	0.13%	2.65%	0.00%	17.29%	0.02%
Synopsys Inc	SNPS	185.75	493.39	91,646.54	0.22%			9.76%	0.02%
CH Robinson Worldwide Inc	CHRW	118.09	132.40	15,635.27	0.04%	1.87%	0.00%	15.51%	0.01%
Accenture PLC	ACN	622.85	246.60	153,595.48		2.64%			
TransDigm Group Inc	TDG	56.35	1,318.02	74,270.81	0.18%			12.86%	0.02%
Yum! Brands Inc	YUM	277.54	152.00	42,185.43	0.10%	1.87%	0.00%	9.48%	0.01%
Prologis Inc	PLD	926.18	114.52	106,065.56	0.26%	3.53%	0.01%	5.72%	0.01%
FirstEnergy Corp	FE	577.13	45.82	26,443.92		3.88%		-4.30%	
VeriSign Inc	VRSN	93.40	279.57	26,111.84		1.10%			
Quanta Services Inc	PWR	149.01	414.32	61,736.16	0.15%	0.10%	0.00%	14.67%	0.02%
Henry Schein Inc	HSIC	121.27	66.37	8,048.58	0.02%			4.67%	0.00%
Ameren Corp	AEE	270.41	104.38	28,225.39	0.07%	2.72%	0.00%	8.89%	0.01%
FactSet Research Systems Inc	FDS	37.81	286.49	10,831.26		1.54%			
NVIDIA Corp	NVDA	24,300.00	186.58	4,533,894.00		0.02%		39.00%	
Cognizant Technology Solutions Corp	CTSH	488.40	67.07	32,756.72		1.85%			
Intuitive Surgical Inc	ISRG	358.48	447.23	160,321.45	0.39%			15.50%	0.06%
Take-Two Interactive Software Inc	TTWO	184.47	258.36	47,659.72				58.37%	

		[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 Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Republic Services Inc	RSG	312.22	229.48	71,647.29	0.17%	1.09%	0.00%	9.49%	0.02%
eBay Inc	EBAY	457.00	90.95	41,564.15	0.10%	1.28%	0.00%	10.81%	0.01%
Goldman Sachs Group Inc/The	GS	302.72	796.35	241,071.94	0.59%	2.01%	0.01%	13.64%	0.08%
SBA Communications Corp	SBAC	107.38	193.35	20,761.73	0.05%	2.30%	0.00%	8.73%	0.00%
Sempra	SRE	652.47	89.34	58,288.63		2.89%			
Moody's Corp	MCO	179.00	476.48	85,289.92		0.79%			
ON Semiconductor Corp	ON	408.97	49.31	20,166.51				-3.65%	
Booking Holdings Inc	BKNG	32.41	5,399.27	174,989.75	0.43%	0.71%	0.00%	16.74%	0.07%
F5 Inc	FFIV	57.45	323.19	18,566.35	0.05%			7.13%	0.00%
Akamai Technologies Inc	AKAM	143.39	75.76	10,862.89	0.03%			4.90%	0.00%
Charles River Laboratories International Inc	CRL	49.21	156.46	7,700.05	0.02%			3.67%	0.00%
Devon Energy Corp	DVN	634.80	35.06	22,256.09	0.05%	2.74%	0.00%	4.26%	0.00%
Bio-Techne Corp	TECH	155.69	55.63	8,661.09		0.58%			
Alphabet Inc	GOOGL	5,817.00	243.10	1,414,112.70	3.44%	0.35%	0.01%	12.93%	0.44%
Allegion plc	ALLE	85.85	177.35	15,224.88	0.04%	1.15%	0.00%	5.69%	0.00%
Netflix Inc	NFLX	424.93	1,198.92	509,452.70				26.62%	
Warner Bros Discovery Inc	WBD	2,475.77	19.53	48,351.83				40.59%	
Agilent Technologies Inc	A	283.50	128.35	36,387.28	0.09%	0.77%	0.00%	7.99%	0.01%
Trimble Inc	TRMB	237.97	81.65	19,430.18					
Elevance Health Inc	ELV	225.18	323.12	72,759.61		2.12%		-0.92%	
CME Group Inc	CME	360.38	270.19	97,370.27	0.24%	1.85%	0.00%	5.71%	0.01%
DTE Energy Co	DTE	207.52	141.43	29,349.24	0.07%	3.08%	0.00%	6.37%	0.00%
Nasdaq Inc	NDAQ	573.80	88.45	50,752.19	0.12%	1.22%	0.00%	15.63%	0.02%
Philip Morris International Inc	PM	1,556.59	162.20	252,478.79	0.61%	3.63%	0.02%	11.27%	0.07%
Salesforce Inc	CRM	952.00	237.00	225,624.00	0.55%	0.70%	0.00%	12.74%	0.07%
Ingersoll Rand Inc	IR	397.45	82.62	32,837.53		0.10%			
Huntington Ingalls Industries Inc	HII	39.24	287.91	11,297.77	0.03%	1.88%	0.00%	14.49%	0.00%
Roper Technologies Inc	ROP	107.61	498.69	53,665.94		0.66%			
MetLife Inc	MET	665.03	82.37	54,778.20	0.13%	2.76%	0.00%	12.81%	0.02%
Tapestry Inc	TPR	209.07	113.22	23,670.74	0.06%	1.41%	0.00%	7.22%	0.00%
CSX Corp	CSX	1,864.28	35.51	66,200.48	0.16%	1.46%	0.00%	6.33%	0.01%
Edwards Lifesciences Corp	EW	587.10	77.77	45,658.77	0.11%			8.64%	0.01%
Ameriprise Financial Inc	AMP	94.27	491.25	46,310.91	0.11%	1.30%	0.00%	10.55%	0.01%
Zebra Technologies Corp	ZBRA	50.85	297.16	15,109.14					
Zimmer Biomet Holdings Inc	ZBH	198.10	98.50	19,512.45	0.05%	0.97%	0.00%	4.65%	0.00%
CBRE Group Inc	CBRE	297.55	157.56	46,882.66					
Camden Property Trust	CPT	106.85	106.78	11,409.73	0.03%	3.93%	0.00%	1.63%	0.00%
Mastercard Inc	MA	897.27	568.81	510,378.52	1.24%	0.53%	0.01%	15.34%	0.19%
Datadog Inc	DDOG	323.27	142.40	46,033.75	0.11%			8.38%	0.01%
CarMax Inc	KMX	146.85	44.87	6,588.94	0.02%			15.69%	0.00%
Intercontinental Exchange Inc	ICE	572.42	168.48	96,441.84	0.23%	1.14%	0.00%	14.37%	0.03%
Smurfit WestRock PLC	SW	522.14	42.57	22,227.68		4.05%		72.38%	
Fidelity National Information Services Inc	FIS	522.38	65.94	34,445.64		2.43%			
Chipotle Mexican Grill Inc	CMG	1,340.89	39.19	52,549.28	0.13%			15.60%	0.02%
Wynn Resorts Ltd	WYNN	103.98	128.27	13,337.07	0.03%	0.78%	0.00%	4.22%	0.00%
Live Nation Entertainment Inc	LYV	234.47	163.40	38,312.84					
Assurant Inc	AIZ	50.46	216.60	10,929.46		1.48%			
NRG Energy Inc	NRG	193.43	161.95	31,326.12		1.09%			
Regions Financial Corp	RF	892.31	26.37	23,530.17	0.06%	4.02%	0.00%	7.96%	0.00%
Monster Beverage Corp	MNST	976.43	67.31	65,723.38	0.16%			14.71%	0.02%
Mosaic Co/The	MOS	317.38	34.68	11,006.68	0.03%	2.54%	0.00%	3.57%	0.00%
Baker Hughes Co	BKR	985.88	48.72	48,032.03	0.12%	1.89%	0.00%	9.16%	0.01%
Expedia Group Inc	EXPE	118.19	213.75	25,263.57	0.06%	0.75%	0.00%	18.12%	0.01%
Kimberly-Clark Corp	KMB	331.78	124.34	41,253.52	0.10%	4.05%	0.00%	1.97%	0.00%
CF Industries Holdings Inc	CF	161.97	89.70	14,528.97		2.23%		-4.53%	
Leidos Holdings Inc	LDOS	128.30	188.96	24,243.06	0.06%	0.85%	0.00%	9.35%	0.01%
APA Corp	APA	357.79	24.28	8,687.06		4.12%			
TKO Group Holdings Inc	TKO	82.14	201.96	16,588.37		1.51%		93.41%	
Alphabet Inc	GOOG	5,430.00	243.55	1,322,476.50	3.21%	0.34%	0.01%	12.93%	0.42%
First Solar Inc	FSLR	107.25	220.53	23,651.32				37.61%	
Visa Inc	V	1,698.68	341.38	579,896.24	1.41%	0.69%	0.01%	13.36%	0.19%
Mid-America Apartment Communities Inc	MAA	117.07	139.73	16,358.35	0.04%	4.34%	0.00%	1.55%	0.00%
Xylem Inc/NY	XYL	243.41	147.50	35,902.93		1.08%			
Marathon Petroleum Corp	MPC	304.02	192.74	58,596.87	0.14%	1.89%	0.00%	7.16%	0.01%
Advanced Micro Devices Inc	AMD	1,622.84	161.79	262,559.88				31.34%	
Tractor Supply Co	TSCO	529.95	56.87	30,138.35	0.07%	1.62%	0.00%	9.79%	0.01%
ResMed Inc	RMD	146.41	273.73	40,078.13	0.10%	0.88%	0.00%	9.57%	0.01%
Mettler-Toledo International Inc	MTD	20.60	1,227.61	25,287.59	0.06%			7.93%	0.00%
Jacobs Solutions Inc	J	119.54	149.86	17,913.74	0.04%	0.85%	0.00%	13.35%	0.01%
Copart Inc	CPRT	967.73	44.97	43,518.89					
VICI Properties Inc	VICI	1,066.37	32.61	34,774.32	0.08%	5.52%	0.00%	4.24%	0.00%
Fortinet Inc	FTNT	766.27	84.08	64,427.65	0.16%			10.99%	0.02%
Albemarle Corp	ALB	117.68	81.08	9,541.73		2.00%		83.68%	
Moderna Inc	MRNA	389.08	25.83	10,049.93	0.02%			18.60%	0.00%
Essex Property Trust Inc	ESS	64.40	267.66	17,238.38	0.04%	3.84%	0.00%	2.46%	0.00%
CoStar Group Inc	CSGP	423.65	84.37	35,743.38				40.81%	
Realty Income Corp	O	914.31	60.52	55,334.26	0.13%	5.34%	0.01%	3.14%	0.00%
Palantir Technologies Inc	PLTR	2,274.26	182.42	414,870.80				40.62%	
Westinghouse Air Brake Technologies Corp	WAB	170.95	200.47	34,270.98	0.08%	0.50%	0.00%	14.51%	0.01%
Pool Corp	POOL	37.32	310.07	11,571.20	0.03%	1.61%	0.00%	5.27%	0.00%
Western Digital Corp	WDC	346.92	120.06	41,651.47	0.10%	0.33%	0.00%	19.43%	0.02%
PepsiCo Inc	PEP	1,369.08	140.44	192,273.20	0.47%	4.05%	0.02%	3.51%	0.02%
TE Connectivity PLC	TEL	295.48	219.53	64,867.05	0.16%	1.29%	0.00%	10.89%	0.02%
Diamondback Energy Inc	FANG	289.49	143.10	41,425.46		2.80%			
Palo Alto Networks Inc	PANW	668.90	203.62	136,201.42	0.33%			11.82%	0.04%
ServiceNow Inc	NOW	208.00	920.28	191,418.24					
Church & Dwight Co Inc	CHD	243.61	87.63	21,347.43	0.05%	1.35%	0.00%	6.71%	0.00%
Federal Realty Investment Trust	FRT	86.27	100.18	8,642.14	0.02%	4.51%	0.00%	4.15%	0.00%
MGM Resorts International	MGM	272.19	34.66	9,434.14	0.02%			9.69%	0.00%
American Electric Power Co Inc	AEP	534.79	112.50	60,164.41	0.15%	3.31%	0.00%	5.30%	0.01%
Invitation Homes Inc	INVH	613.01	29.33	17,979.53	0.04%	3.95%	0.00%	3.59%	0.00%
PTC Inc	PTC	119.79	203.02	24,320.31				21.45%	
JB Hunt Transport Services Inc	JBHT	96.80	134.17	12,987.56	0.03%	1.31%	0.00%	13.09%	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 Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Lam Research Corp	LRCX	1,261.03	133.90	168,852.22	0.41%	0.78%	0.00%	14.44%	0.06%
Mohawk Industries Inc	MHK	62.13	128.92	8,010.05	0.02%			4.49%	0.00%
Pentair PLC	PNR	163.93	110.76	18,157.03	0.04%	0.90%	0.00%	9.47%	0.00%
GE HealthCare Technologies Inc	GEHC	456.56	75.10	34,287.81	0.08%	0.19%	0.00%	6.34%	0.01%
Vertex Pharmaceuticals Inc	VRTX	256.39	391.64	100,412.83					
Amcor PLC	AMCR	2,308.36	8.18	18,882.38	0.05%	6.23%	0.00%	8.74%	0.00%
Meta Platforms Inc	META	2,168.96	734.38	1,592,842.67	3.87%	0.29%	0.01%	16.81%	0.65%
T-Mobile US Inc	TMUS	1,125.42	239.38	269,402.81		1.70%			
United Rentals Inc	URI	64.34	954.66	61,423.99	0.15%	0.75%	0.00%	7.70%	0.01%
Honeywell International Inc	HON	634.90	210.50	133,645.73	0.32%	2.26%	0.01%	8.09%	0.03%
Alexandria Real Estate Equities Inc	ARE	172.96	83.34	14,414.40		6.34%		-1.68%	
Robinhood Markets Inc	HOOD	773.96	143.18	110,816.12	0.27%			14.47%	0.04%
Delta Air Lines Inc	DAL	652.95	56.75	37,054.82	0.09%	1.32%	0.00%	4.60%	0.00%
Seagate Technology Holdings PLC	STX	212.97	236.06	50,273.29		1.22%		23.91%	
United Airlines Holdings Inc	UAL	327.70	96.50	31,623.42	0.08%			7.43%	0.01%
News Corp	NWS	188.03	34.55	6,496.48		0.58%			
Centene Corp	CNC	491.13	35.68	17,523.63				-21.26%	
Block Inc	XYZ	549.57	72.27	39,717.71				34.36%	
Martin Marietta Materials Inc	MLM	60.31	630.28	38,009.67		0.53%		-9.33%	
Apollo Global Management Inc	APO	575.38	133.27	76,681.06	0.19%	1.53%	0.00%	12.27%	0.02%
Teradyne Inc	TER	159.07	137.64	21,894.88	0.05%	0.35%	0.00%	15.18%	0.01%
PayPal Holdings Inc	PYPL	955.38	67.06	64,067.68	0.16%			12.38%	0.02%
Tesla Inc	TSLA	3,325.15	444.72	1,478,761.10					
Blackrock Inc	BLK	154.85	1,165.87	180,538.86	0.44%	1.79%	0.01%	12.40%	0.05%
Arch Capital Group Ltd	ACGL	373.22	90.73	33,862.28	0.08%			2.01%	0.00%
KKR & Co Inc	KKR	890.95	129.95	115,778.79		0.57%			
Dow Inc	DOW	705.76	22.93	16,183.18	0.04%	6.11%	0.00%	3.37%	0.00%
Everest Group Ltd	EG	41.94	350.23	14,689.80		2.28%		29.71%	
Teledyne Technologies Inc	TDY	46.89	586.04	27,478.54	0.07%			10.05%	0.01%
GE Vernova Inc	GEV	272.22	614.90	167,390.50		0.16%			
Domino's Pizza Inc	DPZ	33.95	431.71	14,656.09	0.04%	1.61%	0.00%	9.94%	0.00%
News Corp	NWSA	376.78	30.71	11,570.80		0.65%			
Exelon Corp	EXC	1,009.54	45.01	45,439.20	0.11%	3.55%	0.00%	7.22%	0.01%
Global Payments Inc	GPN	242.61	83.08	20,155.80		1.20%			
Crown Castle Inc	CCI	435.47	96.49	42,018.51		4.40%		32.78%	
Align Technology Inc	ALGN	72.49	125.22	9,076.74	0.02%			10.93%	0.00%
Kenvue Inc	KVUE	1,919.07	16.23	31,146.50		5.11%		32.40%	
Targa Resources Corp	TRGP	215.19	167.54	36,053.24		2.39%		21.00%	
Bunge Global SA	BG	200.06	81.25	16,255.04	0.04%	3.45%	0.00%	2.09%	0.00%
Deckers Outdoor Corp	DECK	148.34	101.37	15,037.57	0.04%			4.14%	0.00%
LKQ Corp	LKQ	257.29	30.54	7,857.73		3.93%			
Workday Inc	WDAY	217.00	240.73	52,238.41					
Zoetis Inc	ZTS	443.18	146.32	64,846.61	0.16%	1.37%	0.00%	8.70%	0.01%
Paramount Skydance Corp	PSKY	1,064.65	18.92	20,143.24		1.06%			
Coinbase Global Inc	COIN	226.16	337.49	76,326.44				-3.18%	
Digital Realty Trust Inc	DLR	341.05	172.88	58,960.80	0.14%	2.82%	0.00%	6.48%	0.01%
Equinix Inc	EQIX	97.86	783.24	76,650.99		2.40%		32.66%	
Las Vegas Sands Corp	LVS	686.45	53.79	36,924.34	0.09%	1.86%	0.00%	8.34%	0.01%
Molina Healthcare Inc	MOH	54.20	191.36	10,371.71				-9.17%	

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 September 30, 2025
[5] Source: Bloomberg Professional as of September 30, 2025
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of September 30, 2025
[9] Equals [7] x [8]
[10] Source: Bloomberg Professional, as of September 30, 2025
[11] Equals [7] x [10]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

BOND YIELD PLUS RISK PREMIUM ANALYSIS

EXHIBIT 510

November 2025

BOND YIELD PLUS RISK PREMIUM

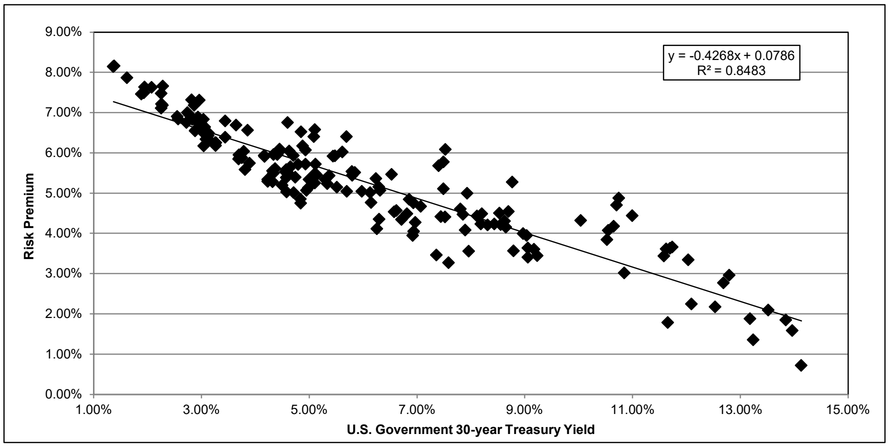
	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	9.97%	4.58%	5.40%
2024.3	9.58%	4.23%	5.35%
2024.4	9.70%	4.50%	5.21%
2025.1	9.73%	4.72%	5.02%
2025.2	9.69%	4.84%	4.86%
2025.3	9.60%	4.85%	4.75%
AVERAGE	11.31%	6.02%	5.29%
MEDIAN	10.67%	5.11%	5.45%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9210434
R Square	0.8483210
Adjusted R Square	0.8474641
Standard Error	0.0055326
Observations	179

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03030	0.03030	989.93815	0.00000
Residual	177	0.00542	0.00003		
Total	178	0.03572			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0786	0.00	85.83	0.0000	0.0768	0.0804	0.0768	0.0804
U.S. Govt. 30-year Treasury	(0.4268)	0.01	(31.46)	0.0000	(0.4536)	(0.4001)	(0.4536)	(0.4001)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.81%	10.60%
Blue Chip Near-Term Projected Forecast (Q1 2026 - Q1 2027) [5]	4.62%	5.89%	10.51%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.40%	5.98%	10.38%
AVERAGE			10.50%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 30, 2025
[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 September 30, 2025
[5] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.078577 + (-0.426828 x Column [7])
[9] Equals Column [7] + Column [8]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

SIZE PREMIUM

EXHIBIT 511

November 2025

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization

Company	Ticker	[1] Market Capitalization ($ billions)
Atmos Energy Corporation	ATO	26.60
NiSource Inc.	NI	19.55
Northwest Natural Gas Company	NWN	1.72
ONE Gas Inc.	OGS	4.58
Southwest Gas Corporation	SWX	5.64
Median		5.64

Cascade Natural Gas Corporation		
Test Year Rate Base ($millions)	[2]	$ 230.88
Proposed Common Equity Ratio	[3]	50.00%
Common Equity ($ millions)	[4]	$ 115.44
Market Capitalization of Proxy Group (median) ($millions)	[5]	$ 5,636.10

Kroll Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10		[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest		3,522,211.14	-0.01%
2		46,949.06	0.33%
3		20,178.36	0.49%
4		9,937.35	0.50%
5		6,181.27	0.74%
6		3,946.15	1.00%
7		2,464.50	1.19%
8		1,417.45	0.88%
9		729.92	1.73%
10-Smallest		304.48	4.47%
Cascade Natural Gas Corporation - Common Equity	[4]	115.44	4.47%
Proxy Group Market Capitalization (median)	[5]	5,636.10	0.74%
Size Premium	[8]		3.73%

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of September 30, 2025
[2] Data provided by the Company
[3] Data provided by the Company
[4] Equals [2] x [3]
[5] Equals median market capitalization of proxy group x 1000
[6]-[7] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2024
[8] Size Premium of the Company less Size Premium of Proxy Group

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

FLOTATION COST

EXHIBIT 512

November 2025

FLOTATION COST ADJUSTMENT

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	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
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	$ 0.7200	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

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

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, 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:

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

		[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$3.48	$165.62	2.10%	2.18%	2.26%	7.00%	7.30%	7.22%	7.17%	9.35%	9.43%
NiSource Inc.	NI	$1.12	$41.53	2.70%	2.81%	2.92%	9.50%	7.90%	8.44%	8.61%	11.43%	11.54%
Northwest Natural Gas Company	NWN	$1.96	$42.14	4.65%	4.79%	4.98%	6.50%	n/a	5.75%	6.13%	10.92%	11.10%
ONE Gas Inc.	OGS	$2.68	$76.30	3.51%	3.61%	3.74%	4.50%	5.60%	5.94%	5.35%	8.95%	9.09%
Southwest Gas Corporation	SWX	$2.48	$78.30	3.17%	3.34%	3.47%	10.00%	10.40%	13.11%	11.17%	14.51%	14.64%
Mean											11.03%	11.16%
Median											10.92%	11.10%
Flotation Cost Adjustment (Mean)										[21]		0.13%
Flotation Cost Adjustment (Median)										[22]		0.18%

Notes:
[1]-[4] Sources: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated November 19, 2002.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Source: Bloomberg Professional
[11] Source: Bloomberg Professional, equals 30-day average as of September 30, 2025.
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Source: Value Line
[16] Source: Zacks
[17] Source: S&P Capital IQ Pro
[18] Equals Average ([15], [16], [17])
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals Average ([20]) − Average ([19])
[22] Equals Median ([20]) − Median ([19])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CAPITAL EXPENDITURES

EXHIBIT 513

November 2025

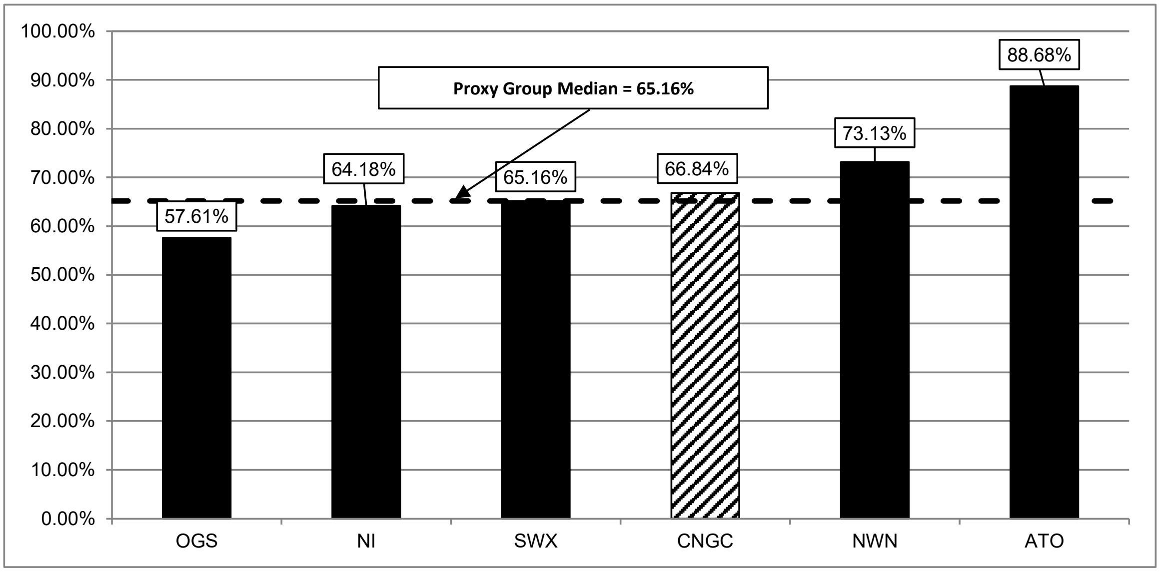
2026-2030 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[3]	[4]	[5]	[6]		[7]
		2024	2026	2027	2028	2029	2030	2026-30 Cap. Ex. / 2024 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$22.75	$22.18	$21.60	$21.60	$21.60	
Common Shares Outstanding			167.00	176.00	185.00	185.00	185.00	
Capital Expenditures			$3,799.3	$3,902.8	$3,996.0	$3,996.0	$3,996.0	88.68%
Net Plant		$22,204.0						
NiSource Inc.	NI							
Capital Spending per Share			$6.00	$6.50	$7.00	$7.00	$7.00	
Common Shares Outstanding			500.00	512.50	525.00	525.00	525.00	
Capital Expenditures			$3,000.0	$3,331.3	$3,675.0	$3,675.0	$3,675.0	64.18%
Net Plant		$27,044.0						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$10.00	$10.75	$11.50	$11.50	$11.50	
Common Shares Outstanding			45.00	47.50	50.00	50.00	50.00	
Capital Expenditures			$450.0	$510.6	$575.0	$575.0	$575.0	73.13%
Net Plant		$3,672.3						
ONE Gas Inc.	OGS							
Capital Spending per Share			$11.60	$11.38	$11.15	$11.15	$11.15	
Common Shares Outstanding			63.00	66.50	70.00	70.00	70.00	
Capital Expenditures			$730.8	$756.4	$780.5	$780.5	$780.5	57.61%
Net Plant		$6,645.9						
Southwest Gas Corporation	SWX							
Capital Spending per Share			$13.50	$14.00	$14.50	$14.50	$14.50	
Common Shares Outstanding			73.00	74.00	75.00	75.00	75.00	
Capital Expenditures			$985.5	$1,036.0	$1,087.5	$1,087.5	$1,087.5	65.16%
Net Plant		$8,109.1						
Cascade Natural Gas Corporation	CNGC							
Capital Expenditures [8]			44.79	33.30	24.91	21.43	20.98	66.84%
Net Plant [9]		$217.6						

CNGC CapEx Total (2026 - 2030)	$145.42
CNGC CapEx Annual Average	$29.1
Proxy Group Median	65.16%
Ratio of CNGC to the Proxy Group Median	1.03

Notes:
[1] - [6] Source: Value Line, dated August 22, 2025
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] - [9] Data provided by Cascade Natural Gas Corporation

2026-2030 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT



Projected CAPEX / 2024 Net Plant

	Company		2026-2030
1	ONE Gas Inc.	OGS	57.61%
2	NiSource Inc.	NI	64.18%
3	Southwest Gas Corporation	SWX	65.16%
4	Cascade Natural Gas Corporation	CNGC	66.84%
5	Northwest Natural Gas Company	NWN	73.13%
6	Atmos Energy Corporation	ATO	88.68%
	Proxy Group Median		65.16%
	Cascade Natural Gas Corporation/Proxy Group		1.03

Notes:
Source: Exhibit CNGC/513, page 1, col. [7]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

REGULATORY RISK ANALYSIS

EXHIBIT 514

November 2025

COMPARISON OF CASCADE NATURAL GAS CORPORATION AND PROXY GROUP COMPANIES
RISK ASSESSMENT

Company	Operating Subsidiary	Jurisdiction	Service	Test Year [1]	Non-Volumetric Rate Design: Revenue Decoupling [2]	Non-Volumetric Rate Design: Formula-based rates [3]	Non-Volumetric Rate Design: Straight Fixed-Variable Rate Design [4]	Overall Revenue Stabilization [5]	Capital Cost Recovery Mechanism [6]
Atmos Energy Corp.	Atmos Energy Corp.	Kansas	Gas	Historical	Yes	No	No	Yes	Yes
	Atmos Energy Corp.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Atmos Energy Corp.	Louisiana	Gas	Historical	Yes	Yes	No	Yes	No
	Atmos Energy Corp.	Mississippi	Gas	Historical	Yes	Yes	No	Yes	Yes
	Atmos Energy Corp.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No
	Atmos Energy Corp.	Texas RRC	Gas	Historical	Yes	Yes	No	Yes	Yes
	Atmos Energy Corp.	Virginia	Gas	Historical	Yes	No	No	Yes	Yes
NiSource Inc.	Northern Indiana Public Service Co	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Northern Indiana Public Service Co	Indiana	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Yes	No	No	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Fully Forecast	Yes	No	No	Yes	Yes
Northwest Natural Gas Company	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No
ONE Gas, Inc.	Kansas Gas Service Co.	Kansas	Gas	Historical	Yes	No	No	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Yes	No	No	Yes	No
	Texas Gas Service Co.	Texas RRC	Gas	Historical	Yes	No	No	Yes	Yes
Southwest Gas Corporation	Southwest Gas Corp.	Arizona	Gas	Historical	Yes	No	No	Yes	Yes
	Southwest Gas Corp.	California	Gas	Fully Forecast	Yes	No	No	Yes	No
	Southwest Gas Corp.	Nevada	Gas	Historical	Yes	No	No	Yes	Yes
Proxy Group Totals		Fully Forecast		8				Yes 21	Yes 17
		Partially Forecast		2				No 1	No 5
		Historical		12					
		Forecast		45.45%				% Yes 95.45%	% Yes 77.27%
Cascade Natural Gas Corporation [7]		Oregon		Fully Forecast	Yes	No	No	Yes	No

Notes
[1] Regulatory Research Associates, effective as of September 30, 2025.
[2] S&P Global Market Intelligence, Adjustment Clauses: a state-by-state overview, dated September 22, 2025. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Adjustment Clauses: a state-by-state overview, dated September 22, 2025.
[5] Equals IF(AND([2]=No, [3]=No, [4]=No), No, Yes)
[6] S&P Global Market Intelligence, Adjustment Clauses: a state-by-state overview, dated September 22, 2025. Yes, if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", "Environmental compliance" or "Transmission costs".
[7] Data provided by Company

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

RRA REGULATORY RANKINGS

EXHIBIT 515

November 2025

COMPARISON OF CNGC AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
		Rank	Numeric Rank
Atmos Energy Corporation	Kansas	Average/3	6
	Kentucky	Average/2	5
	Louisiana — PSC	Average/2	5
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Texas — RRC	Average/1	4
NiSource Inc.	Indiana	Average/1	4
	Kentucky	Average/2	5
	Maryland	Below Average/3	9
	Ohio	Average/1	4
	Pennsylvania	Above Average/2	2
	Virginia	Average/1	4
Northwest Natural Gas Company	Oregon	Average/3	6
	Washington	Average/3	6
ONE Gas, Inc.	Kansas	Average/3	6
	Oklahoma	Average/3	6
	Texas — RRC	Average/1	4
Southwest Gas Corporation	Arizona	Below Average/2	8
	California	Average/2	5
	Nevada	Average/1	4
Proxy Group Average		Average / 1 - Average / 2	4.95
Cascade Natural Gas Corporation	Oregon	Average/3	6.00

Notes
[1] Source: State Regulatory Evaluations, Regulatory Research Associates, as of June 20, 2025.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

S&P CREDIT SUPPORTIVENESS RANKINGS

EXHIBIT 516

November 2025

COMPARISON OF CNGC AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
Atmos Energy Corporation	Kansas	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Louisiana — PSC	Highly credit supportive	2
	Mississippi	Highly credit supportive	2
	Tennessee	Highly credit supportive	2
	Texas — RRC	Highly credit supportive	2
NiSource Inc.	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Maryland	Very credit supportive	3
	Ohio	Very credit supportive	3
	Pennsylvania	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Northwest Natural Gas Company	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
ONE Gas, Inc.	Kansas	Highly credit supportive	2
	Oklahoma	Very credit supportive	3
	Texas — RRC	Highly credit supportive	2
Southwest Gas Corporation	Arizona	Very credit supportive	3
	California	More credit supportive	4
	Nevada	Very credit supportive	3
Proxy Group Average		Very Credit Supportive / Highly Credit Supportive	2.40
Cascade Natural Gas Corporation	Oregon	More credit supportive	4

Notes
[1] Source: North American Utilities Regulatory Jurisdictions Update: Missouri and Arizona Assessments Revised; Other Notable Developments, Standard and Poor's Ratings Services, May 16, 2025.
[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CAPITAL STRUCTURE

EXHIBIT 517

November 2025

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	60.26%	60.20%	60.01%	60.16%
NiSource Inc.	NI	54.89%	55.44%	54.17%	54.83%
Northwest Natural Gas Company	NWN	49.60%	47.26%	51.21%	49.36%
ONE Gas, Inc.	OGS	68.93%	70.68%	58.24%	65.95%
Southwest Gas Corporation	SWX	48.13%	47.45%	43.96%	46.51%
Proxy Group					
MEAN		56.36%	56.21%	53.52%	55.36%
LOW		48.13%	47.26%	43.96%	46.51%
HIGH		68.93%	70.68%	60.01%	65.95%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	60.26%	60.20%	60.01%	60.16%
Northern Indiana Public Service Company LLC	NI	58.24%	59.26%	56.92%	58.14%
Columbia Gas of Kentucky, Inc.	NI	51.44%	53.66%	54.91%	53.34%
Columbia Gas of Maryland, Inc.	NI	52.00%	52.00%	51.96%	51.99%
Columbia Gas of Ohio, Inc.	NI	50.27%	50.50%	50.67%	50.48%
Columbia Gas of Pennsylvania, Inc.	NI	56.07%	55.88%	56.64%	56.20%
Columbia Gas of Virginia, Inc.	NI	44.58%	45.25%	44.25%	44.69%
Northwest Natural Gas Company	NWN	49.60%	47.26%	51.21%	49.36%
Kansas Gas Service Company, Inc.	OGS	59.53%	60.44%	58.37%	59.45%
Oklahoma Natural Gas Company	OGS	59.23%	60.46%	58.26%	59.32%
Texas Gas Service Company, Inc.	OGS	100.00%	100.00%	58.13%	86.04%
Southwest Gas Corporation	SWX	48.13%	47.45%	43.96%	46.51%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2024, 2023, and 2022 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	39.74%	39.80%	39.99%	39.84%
NiSource Inc.	NI	45.11%	44.56%	45.83%	45.17%
Northwest Natural Gas Company	NWN	50.40%	52.74%	48.79%	50.64%
ONE Gas, Inc.	OGS	31.07%	29.32%	41.76%	34.05%
Southwest Gas Corporation	SWX	51.87%	52.55%	56.04%	53.49%
Proxy Group					
MEAN		43.64%	43.79%	46.48%	44.64%
LOW		31.07%	29.32%	39.99%	34.05%
HIGH		51.87%	52.74%	56.04%	53.49%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	39.74%	39.80%	39.99%	39.84%
Northern Indiana Public Service Company LLC	NI	41.76%	40.74%	43.08%	41.86%
Columbia Gas of Kentucky, Inc.	NI	48.56%	46.34%	45.09%	46.66%
Columbia Gas of Maryland, Inc.	NI	48.00%	48.00%	48.04%	48.01%
Columbia Gas of Ohio, Inc.	NI	49.73%	49.50%	49.33%	49.52%
Columbia Gas of Pennsylvania, Inc.	NI	43.93%	44.12%	43.36%	43.80%
Columbia Gas of Virginia, Inc.	NI	55.42%	54.75%	55.75%	55.31%
Northwest Natural Gas Company	NWN	50.40%	52.74%	48.79%	50.64%
Kansas Gas Service Company, Inc.	OGS	40.47%	39.56%	41.63%	40.55%
Oklahoma Natural Gas Company	OGS	40.77%	39.54%	41.74%	40.68%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	41.87%	13.96%
Southwest Gas Corporation	SWX	51.87%	52.55%	56.04%	53.49%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2024, 2023, and 2022 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2024	2023	2022	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%	0.00%

Notes:
[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.
[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2024, 2023, and 2022 were removed from the analysis.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF TRAVIS R. JACOBSON

EXHIBIT 600

November 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Travis R. Jacobson, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed, for how long, and in what capacity?

A. I am employed by Montana-Dakota Utilities Company ("Montana-Dakota"). Montana-Dakota is part of the MDU Utilities Group which is comprised of Montana-Dakota, Cascade Natural Gas Company ("Cascade" or "Company") and Intermountain Gas Company (collectively the "MDU Utilities Group"), which are all wholly owned subsidiaries of MDU Resources Group, Inc. ("MDU Resources"). I am currently Vice President of Regulatory Affairs. In this capacity, I am primarily responsible for overall regulatory strategy and policy for the MDU Utilities Group.

Q. Please briefly describe your educational background and professional experience.

A. I graduated from Minot State University with a Bachelor of Science degree in Accounting and I am a Certified Public Accountant. In 2019, I completed the Energy Executive Course at the University of Idaho, Moscow. I began my career with the MDU Resources family in 1997 and have held various roles in Financial Reporting & Planning and Regulatory Affairs, including analyst, supervisor, manager, and director, before attaining my current position.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the customer affordability analysis required by recent Oregon legislation; summarize protections in place for Cascade's most vulnerable customers; provide an overview of the Company's approach to the test year and rate base in this case; discuss the rationale behind the

Company's line extension allowance ("LEA") proposal; and discuss the renewable natural gas ("RNG") recovery mechanism being proposed.

Q. Do you sponsor any exhibits in support of your testimony?

A. Yes, I sponsor the following exhibit in support of my testimony:

- Exhibit CNGC/601 – Docket UM 2405, Cascade's Response to Stakeholder Comments

III. CUSTOMER AFFORDABILITY

Q. What is House Bill 3179?

A. The Oregon Legislature passed House Bill ("HB") 3179 in the 2025 legislative session. The bill amends portions of ORS chapter 757 applying to public utilities and changes key aspects of the Public Utility Commission of Oregon's ("Commission") laws governing the filing of rate cases for energy utilities. Among other things, HB 3179 directs the utility to provide an economic impact analysis with its general rate case filing and allows the Commission to consider certain tools for rate mitigation.

Q. Please describe the economic impact analysis required by HB 3179.

A. Section 2 of HB 3179 requires electric and gas utilities, like Cascade, to include specific economic analysis in a rate filing if the utility's proposal would result in a rate increase for the utility's residential customers and the utility's return on equity is subject to review.[1] The analysis must include the cumulative economic impact of the proposed rate increase on residential ratepayers and is required to include six specific categories of analysis:

(1) Bill impacts for residential ratepayers;

(2) Average cost of living and of fuel and utilities in the region;

(3) Data on residential service disconnections;

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[1] HB 3179, 83rd Or. Leg. Assemb., 2025 Gen. Sess. at § 2 (Or. 2025) [hereinafter HB 3179].

(4) Data on overdue balances;

(5) Data on cost of energy for commercial and industrial customers as relative to peers in different states; and

(6) Any other relevant data as determined by the Commission.[2]

Q. Are there any Commission rules that implement those requirements?

A. No, not yet. HB 3179 directs the Commission to establish rules to impose the requirements of the law,[3] but the Commission has not yet finalized those rules. The Commission is currently engaged in the rulemaking process in docket AR 678, but that process will not be completed until after Cascade has filed this general rate case. Cascade has nevertheless conducted the economic impact analysis required by HB 3179 and has included the results of that analysis in this filing.

Q. How did Cascade develop the cumulative economic impact analysis that it conducted as a part of preparing this filing?

A. Cascade retained an outside consultant, Hassan Shaban with Empower Dataworks, to develop the framework for the economic impact analysis. At a workshop held by Commission Staff and attended by stakeholders on September 24, 2025, Cascade presented its proposed framework for the analysis. On October 6, 2025, stakeholders filed comments on Cascade's proposed analysis, including Northwest Natural Gas Company ("NW Natural"), the Alliance for Western Energy Consumers ("AWEC"), and a group of environmental justice advocate organizations consisting of Oregon Just Transition Alliance, Verde, and the Oregon Citizens' Utility Board (the "Energy Justice Advocates"). Cascade reviewed and considered the stakeholders' comments and, where feasible, incorporated them into the Company's planning process as it began to prepare this filing. The Company also responded publicly to all stakeholder comments

[2] HB 3179 at § 2.
[3] HB 3179 at § 2.

in a letter filed in docket UM 2405 on October 16, 2025, which is included as Exhibit CNGC/601.

Q. How did Cascade incorporate stakeholder recommendations into its analysis?

A. Cascade summarized and responded to each stakeholder's recommendations and concerns in its October 16 response letter. Although Cascade noted that many of the comments would be more appropriately addressed in the rulemaking proceeding, Cascade confirmed that the Company's proposal already addressed some stakeholder concerns and incorporated stakeholder feedback where feasible and appropriate.

In particular, Cascade made the following changes, which are reflected in the Company's HB 3179 Cumulative Economic Impact analysis filing:[4]

- Regarding the requirement in Section 2(3)(a) of HB 3179 to consider ratepayers' past utility bills, the Energy Justice Advocates requested that the analysis itemize and present each of the residential charges/fees when summarizing the bill impact for customers.[5] Cascade responded that, in addition to the breakdown of rate impact in the proposal, the Company would itemize taxes and the public purpose charge.[6]

- The Energy Justice Advocates approved of the Company's proposal to incorporate annualized data from February 2021 to September 2025 into the analysis, but were concerned at the proposal to use the date range of July 1, 2024 to June 30, 2025, not including the Company's most recent purchased gas adjustment ("PGA") update.[7] In response, Cascade clarified that the Company had included the latest information available at the time of the proposal, and that the Company would include the most up-to-date data possible in the final analysis.[8] The data presented in the economic impact analysis includes the Company's 2025 PGA, which went into effect October 31, 2025.[9]

- Regarding the requirement in Section 2(3)(c) of HB 3179 to provide analysis on residential service disconnections, the Energy Justice Advocates requested that Cascade include additional disconnection data points from reports in

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[4] Exhibit B to Executive Summary.
[5] CNGC/601, Jacobson/3.
[6] CNGC/601, Jacobson/3.
[7] CNGC/601, Jacobson/3.
[8] CNGC/601, Jacobson/3.
[9] *In re Cascade Nat. Gas Co., Advice No. O25-07-01, Reflects changes to the Purchased Gas Adjustment ("PGA") Tariff, Schedule 177 and Schedule 191 Temp. Gas Cost Rate Adjustment*, Docket No. UG 521, Order No. 25-428 at 1, App. A at 1 (Oct. 28, 2025).

dockets RO 12 and RO 16. In response, Cascade committed to adding data on (i) the number of active residential accounts; (ii) the percentage of disconnected households who are Energy Discount Plan ("EDP") or Oregon Low-Income Bill Assistance ("OLIBA") participants, and (iii) the number of medical certificate households who were disconnected for non-payment.[10]

- The Energy Justice Advocates also requested that Cascade analyze data based on the top twenty most disconnected zip codes.[11] Cascade responded that the Company would include in its analysis zip code-level data for the seven most disconnected zip codes, representing the top quartile of Cascade's service area zip codes.[12]

- Regarding the requirement in Section 2(3)(d) of HB 3179 to provide analysis on overdue balances or arrearages, the Energy Justice Advocates requested that the Company include data for the number of customers currently enrolled in OLIBA and in a time payment arrangement ("TPA").[13] In response, Cascade agreed to include the number of customers enrolled in a TPA under this section of the analysis and clarified that the number of customers enrolled in OLIBA would be included in the disconnection analysis under Section 2(3)(c).[14]

- The Energy Justice Advocates also recommended that Cascade should focus the arrearage analysis on 91+ day arrears.[15] The Company adopted that recommendation for the analysis.[16]

- Regarding the requirement in Section 2(3)(f) of HB 3179 to provide analysis on "any other relevant data," including "indicators of financial hardship, residential customer energy burden or affordability of utility bills," the Energy Justice Advocates requested that Cascade consistently "use the language of 'household'" to describe each affordability metric.[17] Cascade agreed to make that change.[18]

- In addition, the Energy Justice Advocates requested that Cascade analyze how households at 61 to 80 percent of state median income ("SMI") are being impacted by rates.[19] In response, Cascade included affordability metrics and impacts of the requested rate increase for 61 to 80 percent SMI households.[20]

[10] CNGC/601, Jacobson/4.
[11] CNGC/601, Jacobson/4.
[12] CNGC/601, Jacobson/4-5.
[13] CNGC/601, Jacobson/4.
[14] CNGC/601, Jacobson/4.
[15] CNGC/601, Jacobson/4.
[16] CNGC/601, Jacobson/4.
[17] CNGC/601, Jacobson/5.
[18] CNGC/601, Jacobson/5.
[19] CNGC/601, Jacobson/5.
[20] CNGC/601, Jacobson/5.

Q. Did the Company include the cumulative economic impact analysis with the filing of this rate case?

A. Yes. The cumulative economic impact analysis is presented as Exhibit B to the Executive Summary.

Q. What are some key takeaways from the economic impact analysis relative to customer affordability?

A. As detailed in Exhibit B to the Executive Summary, Cascade's proposed Schedule 101 will have a moderate impact on the energy burden of low-income customers. However, current programs and energy assistance spending are expected to be sufficient to mitigate the impacts of the rate case, since existing energy assistance spending exceeds the energy assistance need, and program spending "follows the need." That means that program costs are not limited to an annual budget but are deferred for later recovery, enabling Cascade to match assistance with need in real time. Accordingly, even with the proposed rate increase, the current discount levels are more than sufficient to meet the need.

Additionally, Cascade has maintained low disconnection rates, and less than two percent (96 participants) of Energy Discount Program ("EDP") accounts were disconnected for non-payment in a twelve-month period, which illustrates that the program is effectively keeping income qualified customers connected to their service.

Q. Are there any other provisions of HB 3179 that factor into the Commission's consideration of Cascade's proposed rate revision?

A. Yes. In addition to requiring utilities to conduct cumulative economic analysis under Section 2, Section 3(6) of HB 3179 allows the Commission to implement rate mitigation if the Commission determines that the increase would impact "the ability of residential customers to maintain adequate utility service."

Q. Is Cascade proposing rate mitigation in this case?

A. No, not in addition to existing programs that are offered for energy burdened and low-income customers, which per the analysis presented in Exhibit B to the Executive Summary, will provide adequate mitigation for the rate increase and help residential customers to maintain adequate utility service. As described in the Direct Testimony of Dan L. Tillis,[21] the Company offers its residential customers bill management options and multiple different financial assistance programs to help income-qualified customers stay connected to natural gas service, reduce their energy burden, and maintain a comfortable home environment.

Cascade's financial assistance programs assist customers both with ongoing affordability concerns and with unplanned crises. First, the Company's EDP offers household discounts based on household income level as compared to the federal poverty level or Oregon SMI. This very successful program has seen enrollment increase significantly very recently due to Cascade's efforts to auto-enroll customers, as described in the Direct Testimony of Dan L. Tillis. Second, OLIBA is a grant program that complements EDP by providing arrearage forgiveness to households experiencing a financial crisis. Third, the Company's Winter Help program, funded by customer donations and Company shareholders, provides grants to income constrained households at risk of disconnection for non-payment. Fourth, Cascade has partnered with Community Action Agencies ("CAAs") in its service territory to help eligible customers access federal grants through the Low-Income Home Energy Assistance Program ("LIHEAP") to pay past due bill balances. Fifth, Cascade partners with the Energy Trust of Oregon ("Energy Trust") to offer rebates to Oregon customers to install weatherization measures and high efficiency appliances in homes. And sixth,

[21] CNGC/300, Tillis.

with the help of CAAs, Cascade offers income-qualified households installation of efficiency measures at no direct cost through the Oregon Low-Income Energy Conservation Program ("OLIEC").

Cascade also offers three bill management options: budget payment plans which divide payments equally over twelve months; time payment arrangements for two to twenty-four months to extend due dates on unpaid prior balances; and auto-pay, which automatically withdraws funds on behalf of and with the authorization of the customer.

Cascade has worked on communicating the availability of these programs to customers across a variety of media channels and bridging language and literacy barriers. As a result, the Company has seen increased engagement and participation in these affordability programs.

Q. What is the intent of these programs you have described?

A. The goal of these programs and initiatives is to ensure that Cascade's most vulnerable customers maintain adequate utility service without facing financial burden. Collectively, these existing programs will mitigate the impacts of this rate revision for those most vulnerable customers.

IV. RATE BASE

Q. Please provide an overview of the Company's rate base proposal in this proceeding.

A. The Company proposes a fully forecasted test year in this case, using the twelve months ending October 31, 2027 ("Test Year"). The historical base year is the twelve months ending June 30, 2025 ("Base Year"). Rate base for the Test Year is comprised of utility plant in service; net of accumulated depreciation, with additions and subtractions for contributions in aid of construction; customer deposits; working capital; and accumulated deferred income taxes ("ADIT"). The Company proposes to reflect all anticipated Test Year changes, with the exception of two major projects,[22] in the rate base component, including the incorporation of forecasted plant in service additions and their associated depreciation and deferred tax impacts. Consistent with the matching principle, the Company proposes using a thirteen-month average of monthly averages ("AMA") for the Test Year.

Q. Please describe rate base.

A. Rate base reflects the net investment by a utility in its infrastructure and other assets used to provide service to customers. From a ratemaking perspective, rate base is the amount on which the rate of return is applied to derive the return component of the cost of service.

Q. How is the Company proposing to calculate rate base in the Test Year?

A. The Company is proposing a fully forecasted test year to encourage investment to meet customer needs and Oregon energy goals, while maintaining the financial health of the utility.

Q. Is this a different approach than previous Company filings?

A. Yes.

Q. Why is the Company requesting this treatment?

A. First, as a result of the passage of HB 3179, the Commission has new legislative authority to consider multi-year rate plans ("MYRP") but has not yet established the rules to implement that authority. MYRPs generally contemplate future capital additions and attrition in earnings. The Commission also has authority to consider scheduling which utilities can file rate cases in certain years. In the event that the Commission restricts the timing of the Company's future rate cases, but does not provide a means to address capital additions or attrition through an MYRP or other

[22] The Knott Landfill Project in Bend, Oregon and Pine Creek Project in Richland, Washington, both landfill gas projects.

trackers, Cascade needs a fully forecasted test year incorporating all forecasted capital to support the financial health of the utility. The Company's proposal in this case provides a smooth transition into the MYRP regulatory paradigm and scheduled rate cases, if the Commission determines that those are beneficial modifications to the current regulatory process. Second, it supports the Company's investments in needed infrastructure, while maintaining credit rating support by reducing regulatory lag.

Q. What is "regulatory lag"?

A. Regulatory lag refers to the timing difference between when rates need to change (either up or down) and when the change goes into effect. For example, Cascade experiences regulatory lag during the period between when plant goes into service and when it is reflected in revised rates. Critically, without supportive regulatory tools, regulatory lag can lead to persistent underearning by the utility and can threaten the financial integrity of the utility. In turn, persistent underearning can impede the utility's ability to invest in its system to provide safe and reliable service. This is particularly concerning when such underearning is exacerbated by structural issues in the ratemaking process, like those introduced by HB 3179, including limits on the months in which rate increases can take effect, limits on the number of rate cases that can be filed, and limits on how frequently utilities can file, or during transitions such as a change to MYRPs and scheduled rate case filings.

Q. Has Cascade experienced underearning as a result of regulatory lag in Oregon?

A. Yes. As described in Table 1 of the Direct Testimony of Stephanie Sievert, Cascade has consistently experienced underearning in Oregon as a result of regulatory lag.[23]

[23] CNGC/100, Sievert/13.

Q. Is there a relationship between Oregon's energy policy and ratemaking?

A. Oregon energy policy presently demands significant emissions reductions in the delivery of energy, on both the gas and electric systems, which in turn requires significant new investments. Additionally, Cascade must make investments in its system to continue to provide safe and reliable service to its customers, consistent with its duty to serve. To deliver on its objectives, it is essential that Oregon's energy policy be partnered with modernization of ratemaking to ensure lower cost financing and encourage investment. To support investments in RNG facilities like Cascade is making, the utility needs supportive regulatory mechanisms to make the required investments at the lowest possible cost. Unnecessary regulatory lag threatens the timeliness of recovery of investments, a key criterion in credit rating evaluations.[24] Moody's Ratings' Rating Methodology for Regulated Electric and Gas Utilities specifically identifies this issue:

> *Timeliness of Recovery of Operating and Capital Costs*
>
> In assessing this sub-factor, we consider provisions and cost recovery mechanisms for operating costs, mechanisms that allow operating and/or capital expenditures to be trued up periodically in rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress). We also consider the process and time frame of rate proceedings and the track record of recovery. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may diminish the benefit to the utility. In addition, we consider the lag between the time that a utility incurs a major construction expenditure and the time that the utility will start to recover and/or earn a return on that expenditure.[25]

Additionally, increasing capital expenditures for utilities are broadly beginning to raise concerns regarding regulatory lag given rising costs and the need for

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[24] *See*, *e.g.*, Moody's Ratings, Rating Methodology – Regulated Electric and Gas Utilities (Aug. 6, 2024) (available at https://ratings.moodys.com/api/rmc-documents/426183).
[25] *Id.* at 11.

investments to meet state energy goals.[26] Accordingly, mitigating against unnecessary regulatory lag as the Commission implements MYRP requirements will likely be viewed as credit supportive by ratings agencies.

Q. What sort of customer protection is the Company proposing to balance benefits under a fully forecasted Test Year?

A. First, the Company proposes to use the AMA method for both plant and accumulated depreciation to more accurately reflect the cost of service during the Test Year. Second, the Company will file an attestation confirming utility plant in service at the end of the Test Year matches what is in rates. Third, the Company is not seeking to include the Knott Landfill Project or Pine Creek Project in the fully forecasted Test Year capital expenses despite the potential for those projects to come online during the Test Year. Excluding these projects removes the risk of project delays violating the used and useful standard.

Q. How does the Company propose to address unknown future circumstances that could adversely impact timing for completing projects in the forecasted Test Year?

A. The Company proposes that, following the attestation at the end of the Test Year, parties conduct a portfolio review process. This allows the Company to address changed circumstances during the rate-effective period without creating the perverse incentive to invest based on budget rather than good utility practice and while providing an opportunity for parties to review the Company's costs. This ensures that the Company can respond to changing circumstances and emerging needs while keeping

[26] Ethan Howland, *North American utility credit metrics weaken on rising capex, regulatory lag: Morningstar*, Utility Dive (May 17, 2024) (available at https://www.utilitydive.com/news/electric-utility-credit-metrics-capex-morningstar-eei/716425/) (last accessed Nov. 22, 2025).

capital expenditures within Commission-approved amounts at the portfolio level and ensuring that customers only pay for plant that is used and useful.

Q. Will the Test Year capital additions be used and useful in serving the Company's customers?

A. Yes. The capital additions will be used and useful during the Test Year, thus "presently used for providing utility service to the customer" in accordance with ORS 757.355 for service when rates will be in effect. Further, use of AMA ensures that the fully forecasted Test Year costs accurately reflect the costs to serve customers during the Test Year.

Q. Can the Commission determine those costs were prudently incurred in this proceeding?

A. Yes. The Commission requires utilities to show that investments for which the utility requests recovery were prudently incurred and are used and useful for providing utility service, consistent with ORS 757.355. A determination of prudence is based on what was known or should have been known at the time the decision was made. That information is available and parties can review all forecast Test Year capital expenditures in this case. The forecast capital expenditures also act as a cap, with any overages requiring a subsequent prudence review in a future rate proceeding. The Commission will need to make these same decisions if it adopts MYRPs.

Q. Does the Company's proposal in this proceeding include appropriate customer protections against overfunding plant additions?

A. Yes. In this proceeding, the Company's fully forecasted Test Year proposal strikes an appropriate overall balance by accounting for both Test Year investments and depreciation across the same time period. It is the Company's responsibility to provide safe and reliable service to customers. Providing those services and meeting customer expectations requires Cascade to invest in the system to the benefit of customers who rely on those services. The regulatory compact allows the Company, as a regulated utility, a reasonable opportunity to recover its costs and achieve its allowed return on investments. Rate base proposals that provide the Company with a reasonable opportunity to recover its cost of providing service support customers taking that service and the Company's ability to invest to meet customer needs. An unbalanced approach comes at a cost and, assuming the Company continues to invest in its system consistent with its capital plan, would impede the Company's ability to earn a reasonable return, potentially impacting credit ratings and costs to customers in the long run.

Q. What happens if the Company underspends its capital plan?

A. First, for projects entering service prior to the rate effective date, Cascade will provide an attestation that projects forecasted to cost over $1 million were placed in service as planned. In addition, Cascade will submit a separate attestation for the amount of plant additions it has budgeted to be included in rates during the Test Year. After the Test Year has concluded, Cascade proposes to make a separate filing that compares the actual plant entering service to its budget. If the actual plant entering service is less than the Company's budget on a portfolio basis, then customers would receive a refund. However, any recovery of costs would be capped at Cascade's budget (i.e., the post-Test Year filing cannot increase rates). This is similar to MYRPs in other jurisdictions for subsequent year plant additions.

Q. In summary, if the Commission accepts the Company's approach and allows all Test Year plant additions in the Test Year, will that result in a balanced approach to addressing regulatory lag?

A. Yes. The Company's proposal provides a more reasonable opportunity to achieve its allowed return. Further, under this proposed approach, the Company will still need to manage its actual costs and invest in plant additions prudently and within budget to earn its allowed return. Increasing costs, customer expectations, and regulatory requirements can easily result in required investments that exceed forecasts. Absent a fully forecasted test year, the Company is at risk for persistent regulatory lag related to its costs during the transition to Commission scheduled rate cases because the utility's investment cannot be planned for that cycle. Until Cascade fully transitions to a regular cycle of MYRPs in Oregon, any subsequent year after the Test Year in which the rates established in this proceeding continue to be in effect will compound regulatory lag. The Company's approach adheres to regulatory and accounting principles, supports Test Year investments in the system to provide safe and reliable service, better reflects the cost of service, and strikes an appropriate balance between utility and customer interests.

V. CLIMATE PROTECTION PROGRAM ("CPP") REGULATORY CONTEXT

Q. Please provide a brief description of the CPP.

A. The CPP was adopted by the Oregon Department of Environmental Quality ("DEQ") in November 2024 to, among other things, reduce greenhouse gas ("GHG") emissions in Oregon by establishing a declining limit on the usage of fossil fuel by certain regulated entities, including natural gas utilities. The limit on emissions is reduced over time, with the goal of reaching a 50 percent reduction in emissions from 2017 to 2019 averages by 2035 and a 90 percent reduction in emissions by 2050. Each year, DEQ provides regulated companies with a set number of free compliance instruments, equal to the given year's emissions cap. For every metric ton of GHG emissions a regulated entity is responsible for, it must submit to DEQ either a compliance instrument or a community climate investment ("CCI") credit, which can be earned by contributing funds to emissions reduction projects. The first compliance period for regulated entities started January 1, 2025, and covers emissions through the end of

2027, with the first demonstration of compliance in December 2028. All subsequent compliance periods will be two years. The CPP is discussed in more detail in the Direct Testimony of Hart Gilchrist[27].

Q. Has Cascade presented an updated Integrated Resource Plan ("IRP") analysis detailing its plans for CPP compliance?

A. No, not yet. In docket LC 83, Cascade requested an extension of the deadline to file its next IRP, in part based on needing additional time to reassess compliance plans based on the new CPP rules, among other reasons. The Commission granted Cascade's request, and the deadline for filing the next IRP is May 2027.

Q. How does the CPP bear on the Company's requests in this case?

A. Although the Company is still evaluating its least-cost, least-risk compliance options, a compliance focus has helped to inform the development of the Company's LEA proposal and also informs the Company's investments in RNG facilities and the accompanying request for an RNG recovery mechanism, discussed below.

VI. LINE EXTENSION ALLOWANCE PROPOSAL

Q. Is Cascade proposing to update its LEA in this proceeding?

A. Yes. Cascade is proposing changes to its LEA tariff to reflect updates to the Company's LEA. The Direct Testimony of Zachary L. Harris describes the new LEA tariff and includes the new LEA tariff as Exhibit CNGC/1104.[28]

Q. Why is Cascade proposing an update to its LEA in this proceeding?

A. In Cascade's most recent IRP proceeding, the Commission directed that the Company's "line extension policies need to be revisited, but that it would be best to do so in a future general rate case."[29] In the same docket, in response to Cascade's

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[27] CNGC/1200, Gilchrist.
[28] CNGC/1100, Harris; CNGC/1104, Harris.
[29] *In re Cascade Nat. Gas Corp., 2023 Integrated Res. Plan*, Docket No. LC 83, Order No. 24-158 at 11 (May 31, 2024).

request for an extension of its next IRP filing to May 2027, the Commission adopted Staff's recommendation that the Company address LEA policies in a general rate case filed in 2025:

> Staff recommends review of LEA changes in the context of a general rate case proceeding. This provides an opportunity to make rate design choices with a holistic view of rate spread and rate design factors. If Cascade has not filed a general rate case with LEA changes by the end of 2025, Staff commits to returning to the Commission in the first quarter of 2026 with new recommendations for direction to the Company.[30]

In response to the Commission's direction to present an updated LEA policy in its next general rate case, Cascade has presented the requisite analysis and proposal—summarized here and described in further detail in the Direct Testimony of Zachary L. Harris—in this general rate case.[31]

Q. Are gas utilities required to adopt policies that balance costs of new connections between customer classes?

A. Yes. In accordance with the Commission's rules, Cascade is required to have an LEA policy that implements a balance of customer costs by making line extensions free to a new customer requesting connection and adjusting for expected revenue from the investment of connecting that new customer to the system.[32] LEAs are a widely used methodology to meet that regulatory requirement by preventing subsidies, between new and existing customers.

Oregon law also prohibits all utilities from discriminating when providing service.[33] LEAs allow the Company to avoid disparate treatment of new and existing

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[30] Docket No. LC 83, Order No. 25-370 at 1, App. A at 4 (Sep. 17, 2025).
[31] CNGC/1100, Harris.
[32] *See* OAR 860-021-0050(1) ("Each gas utility shall develop, with the Commission's approval, a uniform policy governing the amount of service extension that will be made free to connect a new customer. This policy should be related to the investment that can prudently be made for the probable revenue.").
[33] ORS 757.310(2); ORS 757.325.

customers by balancing the costs of connecting new customers with the benefits to existing customers of expanding the Company's customer base.

Q. Please provide general background on Cascade's current LEA and describe the reasons for the policy.

A. Cascade's current LEA policy comprises provisions in two of the Company's tariffs, Rule 9, Service Line Extensions, and Rule 10, Main Extensions. The details of those rules are described in the Direct Testimony of Zachary L. Harris.[34] Altogether, Cascade's current LEA policy reduces the cost barrier of entry for new customers seeking to establish a connection to natural gas service.

Cascade's current LEA provides for a footage allowance depending on the type of appliances that will be installed. This approach is premised on the idea that when a new customer is connected to gas service, there is a cost associated with constructing infrastructure necessary to extend service to that new customer, and the new connection will also contribute to covering system costs, providing benefits to Cascades existing customers. Adding more customers spreads those fixed costs amongst more individuals, decreasing the overall cost of service to an individual customer. Thus, Cascade's current LEA is intended to balance the cost expended to connect a new customer with the cost benefits for existing customers as a result of that new connection.

Q. Please provide an overview of the Commission's recent decisions regarding LEAs.

A. Electric utilities' LEA policies have recently received relatively uncontroversial approval. Portland General Electric ("PGE") filed for approval of an update to its LEA

[34] CNGC/1100, Harris.

policy for its residential customers in June 2024.[35] PGE proposed to set its residential LEA to four times the expected annual and basic distribution charge revenues: $3,520 for its Residential Service All Electric customers and $2,730 for its Residential Service Primary Other customers.[36] Staff recommended that the Commission approve the proposal, finding the proposed multiplier to be reasonable[37] but recommending that, in order to better monitor for over-subsidization, the Commission should direct PGE to involve interested parties in a review of the LEAs using updated energy use data by June 2029.[38] The Commission agreed, and adopted Staff's recommendation to approve PGE's proposal.[39]

In December 2024, Idaho Power also filed an update to its line extension tariff to reflect updated costs and to seek an increase in the amount of the customer allowance for a line extension from $3,681 to $3,987 for the residential or single phase allowance.[40] The Commission approved that filing, adopting Staff's recommendation that Idaho Power's proposed revisions were reasonable.[41]

PacifiCorp's current LEA policy has been in place since 2012 and provides a per-residence extension allowance of $1,100 for permanent residential applications and $500 for permanent residential applications in a planned development.[42]

However, for gas utilities, the Commission has taken a different approach in recent years. In NW Natural's 2022 rate case, the Commission directed NW Natural

[35] *In the Matter of Portland Gen. Elec. Co., Updates Schedule 300, Line Extension Allowance, Revising Residential Line Extension Allowance*, Docket No. UE 443, Advice No. 24-13 (Jun. 28, 2024) (cross referencing Docket No. ADV 1630).
[36] *Id*. at 1.
[37] Docket No. UE 443, Order No. 24-362, App. A at 4 (Oct. 29, 2024).
[38] *Id*. at 6.
[39] Order No. 24-362 at 1.
[40] *In the Matter of Idaho Power Co., Advice No. 24-11 Rule H*, Docket No. ADV 1693, Advice No. 24-11 at 2 (Dec. 20, 2024).
[41] Docket No. ADV 1693, Letter from ALJ Mapes at 1, Item No. CA1 at 3-4 (Feb. 4, 2025).
[42] PacifiCorp Tariff PUC OR No. 36, First Revision of Sheet No. R13-1; PacifiCorp Advice No. 12-001 (Jan. 30, 2012); Docket for Advice No. 12-001, Action Approving Utility Filing (Mar. 13, 2012).

to begin to reduce its LEA, starting with five times annual margin on November 1, 2022, four times annual margin on November 1, 2023, and three times margin on November 1, 2024.[43] The Commission also invited NW Natural to present an alternative LEA proposal accounting for CPP compliance costs in a future case.[44] In NW Natural's 2024 rate case, NW Natural presented an alternative LEA proposal, but the Commission did not adopt it and instead continued the trajectory of phasing out NW Natural's LEA by 2027.[45] NW Natural has appealed the Commission's decision phasing out its LEA to the Oregon Court of Appeals, and those issues are currently under review in that court.[46]

In its 2023 rate case, Avista resolved the disputed issues in that case through a stipulation that included a phase out and elimination of its LEA by 2027.[47] Avista clarified that its agreement to do so "is a compromise among interests and represents give and take."[48]

Q. Did Cascade consider eliminating its LEA entirely based on the phase out and elimination of the LEA for Avista and NW Natural?

A. No. Avista entered into a stipulation to phase out its LEA, which is not binding on any other party. And, while the Commission directed NW Natural to phase out its LEA, Cascade understands that decision is currently under review by the Court of Appeals. Cascade believes there are important legal and policy reasons to maintain an LEA—including compliance with the Commission's rule, OAR 860-021-0050, requiring a

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[43] *In re Nw. Nat. Gas Co. dba NW Natural, Request for a Gen. Rate Revision*, Docket No. UG 435, Order No. 22-388 at 51 (Oct. 24, 2022).
[44] *Id*.
[45] *In re Nw. Nat. Gas Co. dba NW Natural, Request for a Gen. Rate Revision*, Docket No. UG 490, Order No. 24-359 at 12 (Oct. 25, 2024).
[46] *Nw. Nat. Gas Co. dba NW Nat. v. Public Util. Comm'n of Oregon*, Docket No. UG 490, Petition for Judicial Review of Order No. 24-359 (Jan. 23, 2025) (A186401).
[47] *In re Avista Corp. dba Avista Util., Request for a Gen. Rate Revision*, Docket No. UG 461, Order No. 23-384 at 9 (Oct. 26, 2023).
[48] *Id*. at 12.

uniform policy governing the amount of main extension which will be made free to connect a new customer, and with the Company's legal obligation to avoid discrimination in its service to its customers. Offering an LEA ensures that all potential customers have an opportunity to choose gas service, including customers that may not otherwise be able to afford to do so absent the provision of the LEA.

Q. Please describe Cascade's updated LEA proposal.

A. Cascade proposes to consolidate the tariffs for Rules 9 (Services) and 10 (Mains) and, instead of using a combination of a footage-based and margin-based allowance, proposes to move toward one allowance based on 4 times the anticipated margin for the new customers in the residential, commercial and industrial classes and 4.5 times margin for large volume and transportation customers.

Q. How does Cascade's proposed update account for the Commission's directive in the context of emissions reduction regulations?

A. Cascade's updated LEA policy is responsive to the Commission's direction in NW Natural's 2022 general rate case, Order No. 22-388, to consider CPP compliance costs, in that the proposal will result in an overall reduction to the average LEA and will shorten the payback period for the LEA. In that way, the Company's updated LEA policy aligns with the traditional approach to balancing costs and benefits to new and existing customers, while also accounting for CPP compliance costs.

Q. Has Cascade convened a workshop to discuss revisions to its line extension policies?

A. Yes. Cascade held its initial meeting with a small stakeholder group on May 6, 2025. This small group meeting was followed up with a second meeting with interested stakeholders on November 3, 2025.

Q. What was the outcome of the November 3, 2025, meeting with stakeholders?

A. The conversation with parties demonstrated that stakeholders may hold differing views regarding the future of the role of natural gas distribution service in Oregon and, as a result, are not aligned regarding Cascade's LEA proposal. Given the timing of the meeting relative to the filing of this case, Cascade did not request that stakeholders formally provide feedback on the LEA proposal that was presented. However, based on the engagement with stakeholders, Cascade expects to receive additional feedback on its proposal over the course of this proceeding.

Q. Why is Cascade's proposed LEA update good policy?

A. First, Cascade believes natural gas is an excellent fuel of choice for many applications and that natural gas will play an increasingly important role in serving heating load during winter peaks in Oregon. In particular, recent studies have highlighted the constraints facing the electric grid, raising significant questions about resource adequacy in the region. The Northwest Power and Conservation Council ("NPCC") projects a significant increase in regional peak electricity demand[49] and notes that existing power supply and transmission infrastructure in the Pacific Northwest may limit near term growth, particularly for high-demand sectors like data centers.[50] This implies challenges for broader electrification efforts as well. Natural gas policies that work to remove or limit natural gas as a fuel option would have implications on the region.

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[49] Paul Ciampoli, *Council Releases Initial 20-Year Forecast for Pacific Northwest Electricity Demand*, American Public Power Association (May 2, 2025) (available at https://www.publicpower.org/periodical/article/council-releases-initial-20-year-forecast-pacific-northwest-electricity-demand) (last accessed Nov. 22, 2025).

[50] Ethan Howland, *Grid constraints limit near-term data center growth in Northwest: NPCC panelist*, Utility Dive (Dec. 12, 2024) (available at https://www.utilitydive.com/news/data-center-load-northwest-npcc-power-plan-microsoft/735346/) (last accessed Nov. 22, 2025).

Second, the cost to connect to the natural gas system is a barrier to becoming a natural gas customer. Cascade's proposal, included with this filing in Rule 9,[51] (CNGC/1104), diminishes the initial economic hurdle of becoming a natural gas customer without requiring a subsidy from other natural gas customers. While the stakeholders may not be fully aligned with Cascade's proposal, Cascade believes it is the best compromise to enable future customers to have access to energy options. A reasonable, balanced LEA policy, such as the one proposed by Cascade, allows for continued customer choice in its energy providers.

Finally, Cascade's LEA is intended to comply with Oregon statutes prohibiting discrimination and with Commission regulations requiring Cascade to develop and maintain a policy to balance the cost of connecting new customers against the revenue generated by that new customer. In this proceeding, the Company proposes to update its existing LEA policy to align with CPP compliance by lowering the amount of the LEA and shortening the payback period. The proposed update accounts for those costs and serves the purpose that the Company is still required to fulfill under Oregon law and Commission regulations.

VII. RENEWABLE NATURAL GAS RECOVERY MECHANISM

Q. Please describe briefly the cost recovery mechanism that Cascade is proposing in this proceeding.

A. Cascade is proposing an RNG recovery mechanism to recover its costs for future RNG projects including the Knott Landfill project and others that the Company may develop in the coming years. This mechanism is being proposed as a new tariff, Schedule 225, Renewable Natural Gas Cost Recovery Adjustment, and is also discussed in the Direct Testimony of Zachary L. Harris. The tariff is included in Exhibit CNGC/1104.

[51] CNGC/1104, Harris.

Q. What is the statutory authority for an RNG recovery mechanism?

A. Senate Bill ("SB") 98 (2019), codified as ORS 757.390 to 398, provides the statutory authority for an RNG automatic adjustment clause ("AAC"), which the Company refers to here as a recovery mechanism. The Company is proposing an RNG recovery mechanism as a part of its participation in the SB 98 voluntary RNG program and also as a means to provide timely cost recovery for its investments that will be used for purpose of compliance with the Oregon Climate Protection Program ("CPP").

Q. What is the SB 98 voluntary RNG program?

A. The Oregon Legislature has declared that "[r]enewable natural gas provides benefits to natural gas utility customers and to the public" and "[t]he development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Oregon."[52] To implement this policy, the SB 98 program allows natural gas utilities to invest in RNG and provides a way for those utilities to recover the costs associated with RNG procurement and RNG infrastructure. Small gas utilities like Cascade can petition the Commission for approval to participate in the SB 98 program.[53]

Q. Is Cascade approved to have an RNG program under SB 98?

A. Yes. Cascade was the first small gas utility to petition for participation, and the Commission granted the petition and established a rate cap for the Company of five percent, to the extent that the Company was using SB 98 as a cost recovery justification rather than the CPP.[54] Now that the Company is approved to participate

[52] ORS 757.390.
[53] ORS 757.398(1); OAR 860-150-0400(1).
[54] *In re Cascade Nat. Gas Corp., Renewable Nat. Gas Program Petition as Required per OAR 860-150-0400(1)*, Docket No. UM 2307, Order No. 24-445 at 1, App. A at 6 (Dec. 11, 2024).

in the SB 98 program, Cascade can request to establish an AAC to recover costs associated with qualifying investments under the program.[55]

Q. How has the Commission previously addressed the interplay between SB 98 and CPP compliance?

A. When the Commission approved Cascade's participation in the SB 98 program, it predicted that CPP compliance would interact with the Company's cost recovery requests for SB 98 RNG projects:

> In approving Cascade Natural Gas Corporation's petition for a SB 98 RNG program, we reiterate that SB 98 projects remain subject to our prudence review, which will consider the management decision to proceed with a resource decision and requested cost allocation in light of other programs, whether in Oregon or other states, in effect. We anticipate a need to take a proactive approach to evaluation of SB 98 justifications relative to CPP compliance strategies.[56]

The Commission made similar statements when it approved NW Natural's RNG AAC in docket UG 435. There, the Commission explained that establishing an RNG AAC under SB 98 was not precluded by the CPP, but evaluation of cost recovery requests in the AAC would include CPP compliance considerations in prudence determinations.[57]

Q. What are the main features of the RNG recovery mechanism that Cascade is proposing in this proceeding?

A. Cascade is proposing an RNG recovery mechanism with the following features. Under the RNG recovery mechanism tariff, all costs associated with qualified RNG investments would be tracked separately from base rates. The Company would file with the Commission requesting approval to include the revenue requirement for new RNG investments in rates. The Company would also annually update the cost of

[55] OAR 860-150-0400(7).
[56] Order No. 24-445 at 1.
[57] Order No. 22-388 at 81-82.

previously approved RNG investments to account for depreciation of those assets. And the Company would confirm that all RNG projects are used and useful, providing service to Oregon customers, prior to changing rates. The Company proposes that RNG project costs approved in the RNG recovery mechanism would be added to rates on October 31 of each year, to account for HB 3179 prohibiting rate changes between November 1 and March 31.[58]

Q. What benefits would Cascade's proposed RNG recovery mechanism have for the Company's customers?

A. The RNG recovery mechanism will allow the Company to recover costs of prudent investments close in time to when the Company's customers receive the benefits of those investments. The RNG recovery mechanism would also allow the Company to update costs outside of a rate case, which is particularly important given that HB 3179 contemplates that in the future, utilities will file multi-year rate cases and may not be able to perfectly time rate case filings to the future RNG investments. And the Company would use the RNG recovery mechanism to annually update the revenue requirements for RNG projects to account for depreciation and corresponding reductions in rate base.

Q. Is Cascade proposing a deferral in connection with the RNG recovery mechanism?

A. Yes. Cascade proposes to file deferrals to capture the costs and benefits of the RNG projects between the time they go into service and the time that cost recovery is approved.

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[58] *See* HB 3179 at § 3(7) (amending ORS 757.210 to prohibit residential rate increases between November 1 and March 31); *see also* HB 3179 at § 14(2) ("ORS 757.210 (7) applies to increases in residential rates that are approved on or after the effective date of this 2025 Act.").

Q. Does Cascade's request in this case address cost allocation amongst customer classes or between Oregon and Washington for the RNG recovery mechanism?

A. No. In this case, Cascade is simply requesting approval for the RNG recovery mechanism and is not proposing a specific cost allocation. Any proposed cost allocation will be linked to the benefits flowing from the particular RNG project, which may be project-specific and would be addressed in a subsequent filing.

Q. Please provide an example of a project for which the Company may seek cost recovery via the RNG recovery mechanism in the future.

A. Cascade is developing an RNG production project that will allow RNG produced from landfill gas collected from Deschutes County's Knott Landfill to flow directly onto Cascade's Bend-area distribution system ("Knott Landfill RNG Project"). This project will provide a new gas supply to Bend, an area of significant growth. Additionally, as discussed in the Direct Testimony of Hart Gilchrist, Cascade's investments in RNG facilities will help to meet the long-term requirements of the Oregon CPP and allow Cascade to make RNG available to its customers on a voluntary basis. Cascade expects that RNG from the project may benefit customers in both Oregon and Washington, similar to other RNG projects that may be located in either state.

Q. What is the status of the Knott Landfill RNG project?

A. In 2023, Cascade executed a contract with Deschutes County to purchase landfill gas from Deschutes County. Cascade will design, construct, and operate the RNG plant to produce RNG that meets pipeline quality specifications from the landfill gas. Currently, Cascade expects the Knott Landfill RNG project to go into service at some point in 2027.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DOCKET UM 2405, CASCADE'S RESPONSE TO STAKEHOLDER COMMENTS

EXHIBIT 601

November 2025

CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.

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October 16, 2025

Oregon Public Utility Commission
Attn: Filing Center
P.O. Box 1088
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RE: UM 2405, Cascade's Response to Stakeholder Comments

On September 29, 2025, the Public Utility Commission of Oregon (Commission) held its first workshop in Docket UM 2405, Investigation into House Bill (HB) 3179 Implementation. At the workshop, Empower Dataworks, on behalf of Cascade Natural Gas Corporation (Cascade or Company), presented a template for complying with the HB 3179 requirement that an energy utility include a cumulative economic impact analysis with any general rate case filing. Interested stakeholders filed comments in response to Empower Dataworks' template. Cascade now files the attached memo, wherein Empower Dataworks, on behalf of Cascade, provides an assessment of Cascade's ability to incorporate parties' requests or recommendations into the cumulative economic impact analysis it will include with its November 2025 general rate case filing.

Cascade appreciates the opportunity to discuss the cumulative economic impact analysis template and to consider parties' comments and perspectives on it. Cascade also looks forward to further defining this requirement in Docket AR 676.

If you have questions about this filing, please contact me at (701) 222-7855 or Mike Parvinen at (509) 528-9223.

Sincerely,

/s/ Travis Jacobson

Travis Jacobson
Vice President, Regulatory Affairs
Cascade Natural Gas Corporation
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Attachments

empower
dataworks

MEMO: Review of stakeholder feedback on proposed template for HB 3179 Economic Impact Analysis for Cascade Natural Gas

Date: 10/15/2025
From: Hassan Shaban, Empower Dataworks
To: Jennifer Gross and Travis Jacobson, Cascade Natural Gas

Context

Several stakeholders provided feedback on the proposed template for a HB 3179 cumulative impact analysis that was presented in a public meeting on 9/24/2025. This document presents my assessment of stakeholder recommendations and which elements can be included in the template given the short timeline and future rulemaking. I appreciate all stakeholders for taking the time and energy to provide their feedback.

– Hassan Shaban
Empower Dataworks
hassan@empowerdataworks.com

Northwest Natural Comments
We agree with Northwest Natural's comments - the proposed template for Cascade was meant as a near-term proposal to satisfy HB 3179 prior to rulemaking and should not be considered precedent-setting. Rulemaking should clarify the data sources, methodology and who is providing the analysis. And in general, duplicate or onerous requirements should be avoided in future economic analyses.

AWEC Comments
AWEC has recommended that Section E in the cumulative analysis (Commercial/Industrial Cost Analysis) include a historical rate impact calculation for each individual rate increase or reduction approved by the Commission, separately for each rate schedule, with detail on both the margin and non-margin (i.e., gas commodity) rate impacts.

We appreciate these suggestions that intend to provide a more detailed look at the rate impacts on commercial/industrial customers. Other stakeholders' feedback indicates that there are different interpretations for the goals of this section (e.g. equity between residential/ non-residential customers, comparison of residential/non-residential rates, impact of non-residential rates on economic development). There appears to be additional workshopping required to reach a consensus on the intent of this section, its content and who is providing the data. For the upcoming Cascade GRC, my recommendation is to stick with the proposed template which meets the requirement in HB 3179 ("Data on the cost of energy for commercial and industrial customers relative to the cost of energy for commercial and industrial customers in other states in the region together with historical trends") and defer this topic to rulemaking for future cumulative economic analyses.

EJ Advocates' Comments

EJ advocates (Oregon Just Transition Alliance, Verde, and Oregon Citizens' Utility Board) have provided detailed feedback on all sections of the proposed economic analysis. A summary of the feedback (in black font) with our actions/response (in blue font) is listed below:

Section A. Bill Impact Analysis

- Break down rate impact by rate structure, and itemizing taxes and public purpose charge: Proposed template includes a breakdown of rate impact - taxes and public purpose charge will also be itemized.
- Analysis should span at least 5 years, but advocates are satisfied with Cascade's look back to previous GRC (almost 5 years): We will proceed with the February 2021 - September 2025 analysis period.
- "*We would like to better understand why the date range of July 1, 2024 to June 30, 2025 was chosen. If Cascade believes this October's power cost adjustment should not be included, it should explain why not."* This was just the latest energy use data available at the time the template was prepared - the final analysis will include more up-to-date data.
- Break down bill impact by EDP tier - This will require a high level of effort and is not feasible before the GRC filing. We would defer to rulemaking for future economic analyses.
- All utilities should include a bill discount tier analysis - We will include the latest bill discount tier analysis in Section F.

Section B. Bill Impact Analysis

- Generally, we are interested in ensuring that any data and analysis (monthly, where available) that comes out from the State of Oregon related to changes in cost of living for Oregonians, should be included in these analyses. This is a valuable recommendation as it will add local context that is lacking in federal/regional data - we will defer to rulemaking as to which additional data sources can be taken into account for the economic analysis.
- Under the Bill Impact Analysis section in Cascade's proposal, there is a note that says, "[Add 2-3 sentences from GRC cover letter on why this rate increase is being requested]." This additional detail is critical to include in this section. We plan to do this.
- Cascade should also report on and analyze its expected return on equity from used and useful as well as planned capital projects, other expected shareholder profits, and expected load growth as utility cost drivers. A lot of this analysis may already be in the main GRC - we will defer to rulemaking as to which specific data/analyses are worthwhile to include in the cumulative economic analysis - either in whole or as a summary.

- Impact of changes in federal funding and Department of Energy grants. We can add this in the narrative, if applicable.

Section C. Disconnection Analysis

- We recommend that Cascade add additional disconnection data points that should be relatively easy to access from its reports in Dockets RO 12 and RO 16. We will add the following data to Section C:
    - Number of active residential accounts
    - Percent of customers who are disconnected for non-payment who are EDP/ Oregon Low-Income Bill Assistance (OLIBA) participants
    - Number of medical certificate households who were disconnected for non-payment
- Cascade should include disconnection data trends over the period of time since Cascade's last GRC. Creating time series data will be a heavy lift and not feasible before the GRC filing - we will defer to rulemaking on whether this is required in future analyses.
- This top 20 disconnected zip code level data should be considered across the various layers of this cumulative economic impact analysis. This includes, where possible, in the sections on Bill Impact, Seasonal Impact, Cost of Living Analysis, Arrearage Analysis and Affordability Analysis. This is a valuable recommendation but compiling geographically granular data will be a heavy lift (except for the affordability analysis) and not feasible before the GRC filing - we will defer to rulemaking on whether this is required in future analyses. There is some zip code-level data that is available through the latest energy burden assessment and it will be included in Section F (Affordability Analysis).

Section D. Arrearage Analysis

- Incorporating data for the number of customers who are currently enrolled in OLIBA (an arrearage support program) and the number of customers who are currently enrolled in a Time Payment Arrangement (TPA), which may have to utilize data from the month prior to the filing. OLIBA participants will be added in Section C. We will add the number of customers on payment arrangements in Section D.
- Focus here on 91+ day arrears at present and how they have changed over time–including how many customers are in this bucket, what the average arrears are, and the total dollars owed. We appreciate the concrete guidance - we will use 91+ days for arrearage reporting
- Cascade should also include EDP tier level data related to arrears–specifically the average, minimum and maximum arrearage balance for customers in each EDP tier. - This is a valuable recommendation but compiling the data will be a heavy lift and not feasible before the GRC filing - we will defer to rulemaking on whether this is required in future analyses.

Section E. Commercial/Industrial Cost Analysis

- For the commercial/industrial customer cost analysis, the utility should break down, by customer class, each of the dollar amounts costs/charges/etc, owed by the customer, by month for the 24 months prior to the date of filing, as well as any projections, estimated or otherwise, expected by the proposed rate effective date. The intent of this section is to provide a comparison to the costs borne by residential customers, necessitating as close to an apples to apples comparison as possible. Please refer to the AWEC comments and our response. This section generally needs some work to establish stakeholder consensus on its intent, what data is included and who will be providing it (utilities vs. Commission). For the upcoming GRC, we intend to submit the proposed analysis that satisfies the text of HB 3179 ("Data on the cost of energy for commercial and industrial customers relative to the cost of energy for commercial and industrial customers in other states in the region together with historical trends").

Section F. Commercial/Industrial Cost Analysis

- We ask Cascade to stick to the language of "household" instead of a mixture of "household" and "customer". Agreed - we will use "household" throughout.
- For example, related to the top 20 most disconnected zip codes in a utility's territory, we are also interested in understanding the EDP participation rate in these zip codes and how it changes over time. Alternatively, we would be interested in an analysis that shows changes from the geographic areas identified in utility EBAs under "Community Profiles" which are noted to have low participation rates for bill discount programs. We will include a snapshot of the participation rates for the 7 most disconnected zip codes (Cascade has about 28 zip codes in its service area, so 7 zip codes would represent the top quartile). Getting the same data over time is a heavy lift and is not feasible prior to this GRC filing.
- Lastly, and generally, we are interested in the inclusion of analysis that helps us better understand how customers at 61-80% state median income (SMI) are being impacted by rates over time. In Section F, we will include the same affordability metrics (energy burden, energy assistance need, and number of high burden households) and impacts of the rate increase for 61-80% SMI households.

Cascade Natural Gas Corporation

Cumulative Economic Impact Analysis [Sample]

Supporting General Rate Case Docket No. XXX

Background

HB 3179 requires that natural gas companies include with their rate case filings an analysis of cumulative economic impact of proposed rates or schedule of rates on the natural gas company's residential ratepayers if the natural gas company's proposed residential rate or schedule of rates will result in an increase of residential rates and the natural gas company's return on equity is subject to review and modification.

The analysis must include:

a. Bill impacts for residential customers
b. Average cost of living and utilities in the region
c. Data on residential service disconnection for nonpayment
d. Data on overdue balances
e. Data on the cost of energy for commercial and industrial customers
f. Any other relevant data, as determined by the commission, such as indicators of financial hardship, residential customer energy burden or affordability of utility bills

Note: Values highlighted in yellow are examples or rough estimates and do not reflect actual values. Unhighlighted values in this example report were current as of July 2025 and may not be the same as those submitted with future GRCs.

A. Bill Impact Analysis

Commented [HS1]: Cascade

Cascade does not have a separate multifamily schedule - all residential customers are under Schedule 101 - General Residential Service Rate. The following table shows the proposed rate structure for schedule 101.

Rate Schedule 101	As of Feb 2021	Current	Proposed
Basic Charge	$6 / month	$6 / month	$XX / month
Energy Discount Program	-	$0.81 / month	$XX / month
Delivery Charge	$0.39467 / therm	$0.39467 / therm	$XX / therm
Cost Of Gas	$0.35568 / therm	$0.51593 / therm	$XX / therm
Other charges (including intervenor funding, decoupling, Energy Discount Program costs, Climate Protection Plan, but not including Public Purpose Charge and municipal taxes)	0.01825 / therm	$0.06775 / therm	$XX / therm
Total Usage Charge	$0.7686 / therm	$0.97835 / therm	$XX / therm
Estimated tax	XX% ?	XX% ?	XX%
Public Purpose Charge	XX%	6.456%	XX%

Commented [HS2]: Add October gas cost adjustment if available

Annualized Impact

Data Source: CC&B, Calculated

Date Range	October 1, 2023 – September 30, 2025
Average Monthly Energy Use (therms)	59
Average Monthly Bill using rates effective as of Feb 2021	$56.81
Current Average Monthly Bill	$72.92
Effective Monthly Difference in Bill since February 2021 due to cost of gas and other adjustments (%)[1]	28.4%
Proposed Average Monthly Bill	$XX

[1] Between February 1, 2021 and May 1, 2025, the cost of gas in Schedule 101 increased from $0.35568 / therm to $0.51593 / therm. Total usage charge was $0.7686/therm in Feb 2021.

Monthly Difference in Bill ($)	$XX
Monthly Difference in Bill (%)	XX%

Seasonal Impact

Data Source: CC&B, Calculated

Date Range	November 1, 2023 - March 31, 2024 and November 1, 2024 - March 31, 2025
Average Monthly Energy Use (therms)	98
Current Average Monthly Bill	$116.03
Proposed Average Monthly Bill	$XX
Monthly Difference in Bill ($)	$XX
Monthly Difference in Bill (%)	XX%

Narrative/Analysis (example): Since the last rate case in February 2021, there has been an effective bill impact of +28.4% (approximately 5-6% annually) due to cost of gas and other adjustments, but the basic and delivery charges on CNGC bills have remained fixed. CNGC is requesting a new rate structure that will translate to an average bill impact for residential customers of +XX%, on an annualized basis and +XX% during winter months.

[Add 2-3 sentences form GRC cover letter on why this rate increase is being requested]

B. Cost of Living Analysis

Commented [HS3]: Empower will update to September or October 2025 if data is available. Otherwise, use as is.

Cascade's last rate increase took effect on February 1st, 2021. The following data outlines the economic situation since that period.

Data Source: Bureau of Labor Statistics: CPI, earnings and PPI. SSA for social security changes.

Date Range	February, 2021 - July, 2025

Cost of living increases [BLS]	
Consumer Price Index for All Urban Consumers, West Region - All Items	+23%
Consumer Price Index for All Urban Consumers, West Region - Electricity	+36%
Consumer Price Index for All Urban Consumers, West Region - Natural Gas	+45%

Household Income	
Household Earnings, CNGC Counties	+23.7%
Social Security Adjustments	+20.3%

Narrative/Analysis (example): Since the last rate case in February 2021, CNGC customers have experienced a +28% bill impact due to the rising cost of natural gas - which is passed through to them through the cost of gas and other adjustments. This is slightly higher than the overall increase in cost of living (+23%), but much lower than the average increase of cost of gas utilities (+45%) and electric utilities (+36%) over that time period in the West region[2]. These increases reflect the cost pressures that utilities in the region have been experiencing.

Household income has kept up with inflation, but fixed incomes have slightly lagged behind cost of living increases (+20.3% increase in social security vs. +23% cost of living increase). CNGC is actively addressing natural gas bill affordability through our assistance programs, including EDP and OLIBA.

[2] OR, WA, CA, ID, NV, AZ, HI, AK

Utility Cost Pressures - National data [BLS PPI]	
Natural Gas Costs	+45.1%
Utility staff wages	+17%
Pipeline transportation	+4.1%
Fluid meters	+36%
Industrial Building Construction	+39.5%

Narrative/Analysis (example): Since the last rate case in February 2021, natural gas costs have increased by +45.1% - this has already been reflected in the cost of gas adjustments passed on to customers (+45% over that time period).
Other utility cost increases shown in the table above (staff wages, construction and equipment) have not been reflected in rates or passed on to customers through the basic or delivery charges. The requested rate adjustment partially seeks to address these increasing cost pressures.

C. Disconnection Analysis

Commented [HS4]: Cascade

Data Source: CC&B report

Date Range	October 1, 2024 - September 30, 2025

# Active accounts	XX
# Customers disconnected due to nonpayment	700 (<1%)
# Customers enrolled in EDP	4,465
# Customers who received an OLIBA grant	XX
# EDP/OLIBA participants who have been disconnected due to nonpayment	XX (Y% of all participants)
# Customers with a medical certificate registered with CNGC	XX
# Customers with a medical certificate registered with CNGC who have been disconnected due to nonpayment	XX

D. Arrearage Analysis

Commented [HS5]: Cascade

Data Source: CC&B report

Date Range	As of September 30, 2025

# Customers with a 91+ day past due balance	XX
Average past due balance (91+ days)	$XX
Total outstanding past due balances (91+ days)	$XX
# Customers enrolled in a Payment Arrangement	XX

Narrative/Analysis (example): CNGC's Oregon customers benefit from a variety of disconnection protections - this is reflected in CNGC's low rate of service disconnection - less than 1% of customers have been disconnected from service in a 12-month period.

The number of customers with past due balances is also relatively low and their arrearage balances are moderate. Customers can set up payment plans or budget billing to help keep up with bills. In addition, low-income customers can take advantage of bill assistance options, including discounts (EDP), grants (LIHEAP, Winter Help), and arrearage assistance (OLIBA). CNGC is currently working on a language access plan to better inform limited-English and limited-literacy customers about these options.

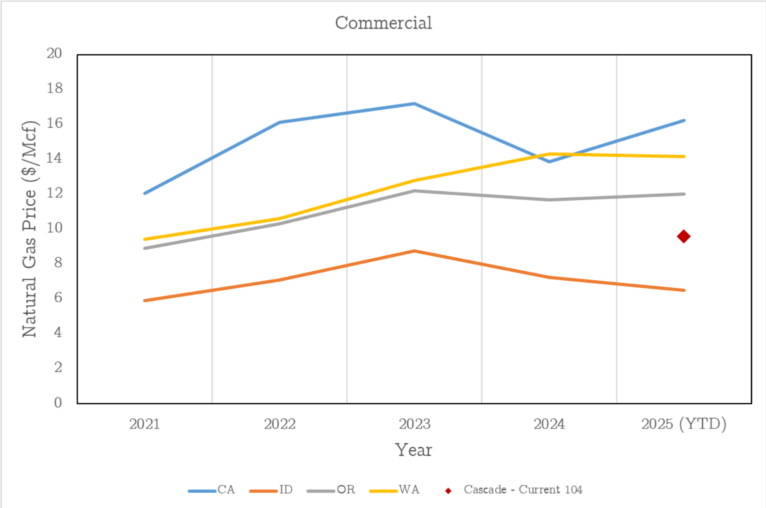
Disconnections due to non-payments and arrearages are actively monitored and reported to the OPUC through RO-16/OAR 860-021-0408(4)(q).

E. Commercial/Industrial Cost Analysis

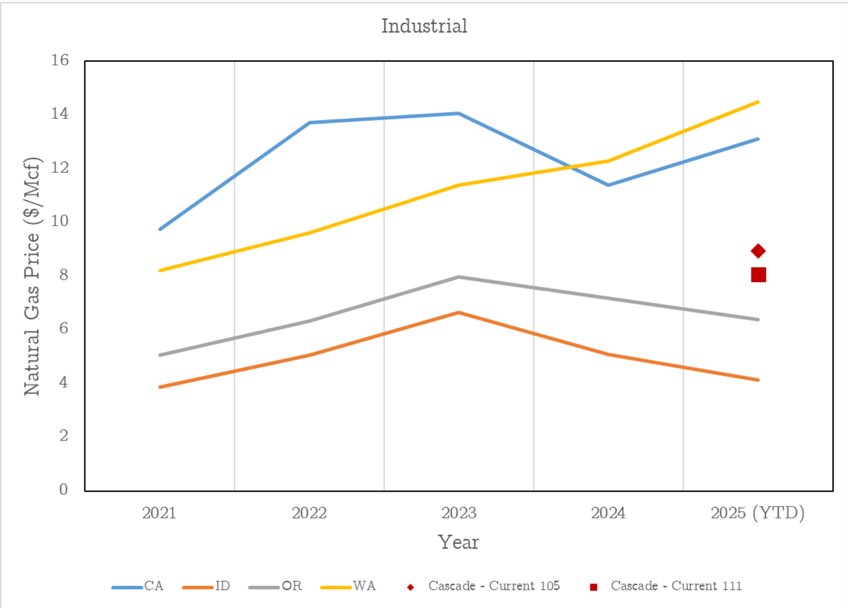
Commented [HS6]: Cascade – update proposed schedule 104

Data Source: EIA
The following data outlines the cost of energy for CNGC commercial and industrial customers compared to other states in the region, together with historical trends. Note that EIA gas prices are based on total sector gas costs divided by total sector consumption - this is a blended rate that includes the basic charge and all taxes. CNGC blended gas prices ($/Mcf) were calculated using rate schedule 104 for an average commercial customer using 3,627 therms/year (based on EIA data for Oregon in 2024). This is not an apples to apples comparison since it does not compare equivalent rate structures.

Rate Schedule 104 - General Commercial	**Current**	**Proposed**
Basic Charge	$12 / month	$XX / month
Delivery Charge	$0.27282 / therm	$XX / therm
Cost Of Gas	$0.51593 / therm	$XX / therm
Other charges (not including Public Purpose Charge and municipal taxes)	$0.05608 / therm	$XX / therm
Total Usage Charge	$0.84483 / therm	$XX / therm
Estimated average tax + PPC	13%	XX%



Narrative/Analysis (example): CNGC's commercial rates have historically been under the average rates for Oregon and regionally (WA, CA), but above the rates in Idaho. The proposed schedule 104 rates are projected to keep average commercial gas costs under those in Oregon, Washington and California.



Narrative/Analysis (example): A similar analysis was conducted using EIA data for the industrial sector, in conjunction with CNGC's schedule 105 - General Industrial Rate and 111-Large Volume General Service.

This is not a perfect apples to apples comparison since EIA's industrial rates include the costs paid by very large industrial customers under high-volume or negotiated rates (for example, Northwest Natural offers a $0.47-0.60/therm rate for large industrial customers).

CNGC's industrial rates have historically been above the average industrial rate in Oregon and Idaho, but below the industrial rates in Washington and California. The proposed industrial rates will have a minimal impact on this regional comparison, as shown in the figure above.

F. Affordability Analysis

Commented [HS7]: Empower

Data Source: 2025 EBA

Date Range	July 1, 2024 - June 30, 2025

Low Income Households	**Current Schedule 101**	**Proposed Schedule 101**
# High burden (>2.5% gas burden)	5,500	XX
Median gas burden	2.2%	XX%
Energy assistance need	$2.03M	$XX
Current program funding as percent of energy assistance need	129%	XX%

Households Earning between 61-80% State Median Income	**Current Schedule 101**	**Proposed Schedule 101**
# High burden (>2.5% gas burden)	5,500	XX
Median gas burden	2.2%	XX%
Energy assistance need	$2.03M	$XX

Zipcode (top 7 by disconnection rate)	**Approximate EDP Participation Rate**
97886	38%
97813	36%
97801	33%
97913	41%
97918	37%
97882	52%
97914	37%
Overall EDP participation rate	~36%

Discount Tier Analysis

Recommendation: Discount levels appear to be high relative to the customers' needs in each income tier - especially considering the absence of post-enrollment verification and 2 year recertification period. Consider revisiting discount design for long-term sustainability of the program.

Income tier	Discount Level	Average assistance need as a percent of bill (not including taxes/PPC)
Tier 1: 0-15% SMI	95%	81%
Tier 2: 16-30% SMI	70%	36%
Tier 3: 31-45% SMI	45%	12%
Tier 4: 46-60% SMI	15%	5%

Reduce Tiers 2 and 3 to 40% and 20% respectively.

Update to 10%

Reduce Tier 1 discount to 80%. Maintain a 95% discount for 0-5% SMI.

Can potentially help an additional 2,400 customers (+54% program growth) for the same budget.

Energy Discount Program discount tier analysis from Cascade Natural Gas Corporation's 2025 Energy Burden Analysis

Narrative/Analysis (example): CNGC's proposed schedule 101 will have a small impact on energy burden. Median energy burden among low-income customers is projected to increase from 2.2 to XX%. The number of high-burden, low-income households is expected to increase by XX% to XX. The energy assistance need is projected to increase to $XX/year (+XX%). Current programs and energy assistance spending are expected to be sufficient to mitigate these impacts, since existing energy assistance spending exceeds the energy assistance need. CNGC will continue its marketing and outreach efforts in order to enroll new customers into its Energy Discount Program.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

DIRECT TESTIMONY OF MATTHEW LARKIN

EXHIBIT 700

November 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Larkin. My business address is 520 Lake Cook Road, Suite 275, Deerfield, Illinois 60015.

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

A. I am employed by MCR Performance Solutions ("MCR") as a Director in the Regulatory Services practice.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration degree in Finance (magna cum laude) from the University of Oregon in 2007. In 2008, I received a Master of Business Administration degree from the University of Oregon. I have also attended multiple electric utility ratemaking courses, including the Electric Rates Advanced Course offered by Edison Electric Institute, and Estimation of Electricity Marginal Costs and Application to Pricing, presented by National Economic Research Associates, Inc.

Q. Please describe your work experience and background.

A. I began my role as a Director in the Regulatory Services practice at MCR in August 2025. Prior to my current role, I was employed for over 16 years at Idaho Power Company, a vertically integrated electric utility serving customers in southern Idaho and eastern Oregon. During my time at Idaho Power Company, I held various positions in the Regulatory Affairs and Finance departments, most recently serving as the Revenue Requirement Senior Manager from 2016 to 2025. I have in-depth experience in a broad array of regulatory areas, including revenue requirement development, class cost-of-service studies ("COSS"), and rate design. I have sponsored testimony before the Idaho Public Utilities Commission and the Public Utility Commission of Oregon ("Commission") and contributed to transmission formula rate filings before the Federal Energy Regulatory Commission ("FERC").

Q. Please describe your role and responsibilities as a Director at MCR.

A. In my role as a Director in the Regulatory Services practice at MCR, I am responsible for performing analyses and managing consulting agreements with utilities throughout the country. The Regulatory Services practice covers a broad array of regulatory matters, including all facets of rate case development, policy support, and strategy development.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Cascade Natural Gas Corporation ("Cascade" or "Company").

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

A. My testimony presents the development of the revenue requirement supporting Cascade's requested base rate increase of $16,167,908, or 15.60 percent. I also present the Company's class COSS that apportions the requested revenue increase to customer classes in accordance with the results of the Long-Run Incremental Cost ("LRIC") analysis.

Q. How is your testimony structured?

A. My testimony begins with a discussion of revenue requirement, detailing the historical base period and fully forecasted test year utilized to quantify the requested revenue increase in this case. In this section I describe in detail the adjustments made to rate base, operating revenues, and operating expenses to determine the level of revenue required from customers during the rate effective period to allow Cascade the opportunity to earn its requested rate of return.

Following the quantification of revenue requirement, my testimony discusses the method by which the requested revenue increase was apportioned to customer classes through the development of the LRIC study. This section discusses each component of the LRIC study in detail, then describes how the results of this study were used to allocate the functionalized test year revenue requirement to customer classes. My testimony concludes with a summary of the COSS results and the cost-based revenue targets for each customer class to be utilized in designing rates.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits in support of my testimony:

- Exhibit CNGC/701 – Witness Qualifications Statement
- Exhibit CNGC/702 – Revenue Requirement Summary
- Exhibit CNGC/703 – Revenue Requirement Calculation
- Exhibit CNGC/704 – Conversion Factor
- Exhibit CNGC/705 – Summary of Adjustments
- Exhibit CNGC/706 – COSS Summary of Results
- Exhibit CNGC/707 – Functionalization of Revenue Requirement
- Exhibit CNGC/708 – Plant Carrying Costs
- Exhibit CNGC/709 – Operations & Maintenance Expenses
- Exhibit CNGC/710 – Annual Carrying Charge Calculations

III. DEVELOPMENT OF REVENUE REQUIREMENT

Q. What does revenue requirement represent?

A. Revenue requirement represents the revenues a utility must collect from customers to cover the cost of providing safe, reliable service to customers while maintaining the opportunity to earn a fair rate of return for investors. This includes all facets of a utility's business, including operations and maintenance expense ("O&M"), the return of a utility's investment through depreciation expense, and the return on undepreciated investment.

Q. What test year was utilized to develop the revenue requirement in this case?

A. As discussed in the Direct Testimony of Travis Jacobson (CNGC/600), the Company is proposing to utilize a fully forecasted test year reflecting the twelve months ending October 31, 2027 ("Test Year"). The historical base year is the twelve months ended June 30, 2025 ("Base Year").

Q. Please generally describe how the revenue requirement was calculated.

A. The starting point for the Test Year revenue requirement was actual historical financial information from the twelve months ended June 30, 2025. Each component of revenue requirement was then analyzed and adjusted to reflect costs and revenues commensurate with the fully forecasted Test Year. I will discuss each of these adjustments in detail in the subsequent sections of my testimony.

A. Rate Base

Q. How was Test Year rate base calculated?

A. Test Year rate base was calculated by developing a monthly forecast of plant-in-service and accumulated depreciation through the final month of the Test Year, October 2027. The starting point for this forecast was actual plant-in-service and accumulated depreciation balances at month-end, June 2025, to which forecasted monthly additions and retirements were applied by FERC account. I then applied a 13-month average-of-monthly-averages ("AMA") approach to determine net plant amounts for the Test Year.

Q. Has Cascade recently received authorization to modify its depreciation rates in the state of Oregon?

A. Yes. On September 24, 2025, the Commission issued an order approving a settlement stipulation that provides for updated depreciation rates effective December 1, 2025.[1]

[1] *In re Cascade Nat. Gas Corp., Petition to File Depreciation Stud.,* Docket No. UM 2380, Order No. 25-377 at 1 (Sept. 24, 2025).

Q. Did you account for this change in depreciation rates in the development of Test Year rate base?

A. Yes. In accordance with the December 1, 2025, effective date, the monthly forecast of accumulated depreciation appropriately reflects the depreciation rates in effect during the corresponding month of the forecast period. In other words, months prior to December 2025 utilize rates in effect at that time, while December 2025 onward utilizes rates in effect stemming from the settlement stipulation approved in docket UM 2380.

Q. Were any adjustments to rate base required due to the Company's proposed modifications to its line extension allowance ("LEA") policy?

A. Yes. As discussed in the Direct Testimonies of Travis Jacobson[2] and Zachary L. Harris,[3] the Company is proposing to modify its LEA by combining the current allowances for service line and main line extensions into a single allowance based on a customer's estimated annual gross margin. This proposal would result in an overall reduction in allowances, meaning new customers will be required to provide upfront funding for a higher proportion of estimated line extension costs relative to the existing policy. Because amounts funded by customers are excluded from revenue requirement, and because the Company's forecast of plant additions is based on the existing policy, the proposed LEA changes necessitate a corresponding adjustment to the Test Year rate base forecast.

[2] CNGC/600, Jacobson.
[3] CNGC/1100, Harris.

Q. How was the Test Year rate base forecast modified to incorporate the proposed LEA modifications?

A. Generally speaking, forecasted capital additions that would be subject to the LEA are contained in growth-related blanket work orders[4] for Account 376: Mains and Account 380: Services. To determine the appropriate Test Year adjustment for the new LEA, a factor was developed representing the average expected reduction in allowances per customer due to the proposed changes. This factor was then applied to the forecast of customer growth beyond the requested rate effective date of October 31, 2026, to calculate an LEA-based reduction of $3,865,912.

Q. Did you calculate accumulated deferred income taxes for the Test Year in accordance with the Test Year forecast of net plant?

A. Yes. Accumulated deferred income taxes were determined based on net plant values for the Test Year.

Q. Is the Company proposing any adjustments to gas inventory, leasehold improvements, materials and supplies, or working cash allowance?

A. No. The Company evaluated Base Year amounts for each of these rate base components and determined that they represent appropriate levels to be included in the forecast Test Year.

<u>B. Operating Revenues</u>

Q. How did the Company calculate operating revenues for the Test Year?

A. For Schedules 101, 104, 105, 163, and 170, operating revenues were calculated for the Test Year by applying existing base rates to expected billing determinants for the twelve months ending October 31, 2027.[5] In addition to these schedules, two special

[4] The term "blanket" refers to work orders that cover broad categories of capital additions, such as service installations for new residential customers.
[5] See the Direct Testimony of Brian L. Robertson (CNGC/1400) for a detailed description of how Test Year billing determinants were developed.

contract customers currently take service under Commission-approved long-term contracts containing formulaic pricing that escalates annually based on changes in the consumer price index ("CPI"). Because the length of these contracts extends beyond October 2027, Test Year operating revenues for these customers were calculated to reflect expected sales volumes multiplied by the CPI-adjusted rates that will be in effect during the Test Year.

Q. Were any additional adjustments necessary to determine appropriate Test Year operating revenues?

A. Yes. Adjustments were necessary related to the Conservation Alliance Plan ("CAP") deferral and non-recurring revenues associated with restructuring at the MDU Resources Group, Inc. ("MDU Resources") level.

Q. Please describe the adjustment related to the CAP deferral.

A. The CAP is the Company's decoupling mechanism for customers on Schedules 101 and 104. Under the mechanics of the CAP, the deferral component captures variances in weather from average conditions. Because Test Year billing components utilized to determine operating revenues are already weather normalized based on Cascade's last general rate case, removal of the CAP deferral was necessary to avoid double-counting the impacts of weather normalization on Test Year sales, as discussed in the testimony of Brian L. Robertson.[6]

Q. Please describe the adjustment related to non-recurring revenues associated with restructuring at the MDU Resources level.

A. Base Year operating revenues include $347,922 in revenues reflecting amounts allocated to Cascade stemming from the spin-off of two business units from MDU

[6] CNGC/1400, Robertson.

Resources. Because these amounts will not recur in the future, they were removed from Base Year operating revenues.

C. Operations and Maintenance Expense

Q. Please generally describe how O&M expense was determined for the Test Year.

A. Similar to rate base and operating revenues, Base Year O&M expenses were analyzed by component and specific adjustments were applied to determine Test Year amounts. These adjustments can be divided into two categories: labor and non-labor.

Q. Please generally describe how the Test Year labor forecast was developed.

A. The starting point for the Test Year labor forecast was actual O&M labor expense for the Base Year. These historical amounts were then adjusted for allowed regulatory treatment of the Company's short-term incentive and Oregon Climate Protection Plan ("CPP") labor. This resulting adjusted base was then split between union and non-union wages, and expected wage increases were applied to each category to determine expected Test Year labor expense.

Q. How was Base Year labor expense adjusted for allowed regulatory treatment of the Company's short-term incentive?

A. First, actual data was adjusted to remove out-of-period accrual and reversal entries related to short-term incentive, isolating actual short-term incentive levels paid in the Base Year. Then, the executive portion of this payment was removed in its entirety in accordance with Commission precedent.[7] After these two adjustments, the remaining short-term incentive amount reflected actual non-executive payments made to employees in the Base Year. Because the short-term incentive during the Base Year was above target levels, a normalizing adjustment was applied to determine the non-executive payout amount that would have occurred at target. Lastly, this target level

[7] *See In re PacifiCorp dba Pacific Power, Request for a Gen. Rate Revision*, Docket No. UE 433, Order No. 24-447 at 56 (Dec. 19, 2024).

non-executive incentive amount was adjusted for prior Commission treatment of the individual components that comprise the short-term incentive.

Q. Please describe the components of Cascade's short-term incentive plan and the Commission precedent for recovery of these amounts.

A. As detailed in the Direct Testimony of Roxanne Roerick,[8] Cascade's short-term incentive is comprised of four components: 1) Financial Performance (70 percent); 2) Customer Satisfaction (10 percent); 3) Reliability (10 percent); and 4) Motor Vehicle Accidents / Safety (10 percent). In accordance with Commission precedent, the financial performance-based component was reduced by 75 percent, while the merit-based components (Customer Satisfaction, Reliability, and Safety) were reduced by 50 percent.[9]

Q. Were any additional adjustments made to Base Year labor?

A. Yes. The Direct Testimony of Hart Gilchrist (CNGC/1200) discusses labor associated with the CPP, and the Company's proposal to shift recovery of these costs into base rates from the current practice of capturing these labor costs under a CPP-specific deferral. In accordance with this proposal, Base Year labor expense was adjusted to include an annualized historic amount of $53,876.

Q. After adjusting Base Year labor costs for short-term incentive and CPP, how were these amounts escalated to determine final Test Year labor expense?

A. After adjusting for short-term incentive and CPP labor, non-incentive Base Year labor was divided between union and non-union wages by applying the average union / non-union split from the four years ending December 2024. These amounts were then escalated based on their respective expected wage increases between the Base Year and the end of the Test Year; non-union labor was escalated by budgeted wage

[8] CNGC/1300, Roerick.
[9] Order No. 24-447 at 56.

increases of 5 percent on January 1, 2026, and January 1, 2027, while union labor was escalated by contract wage adjustment amounts of 4 percent on April 1, 2026, and 3.5 percent on April 1, 2027.

Q. How did the Company develop non-labor O&M expense for the Test Year?

A. Test Year non-labor O&M expense was calculated based on a series of adjustments to different expense components reflecting Commission precedent and expected future conditions during the Test Year. These adjustments are summarized in Exhibit CNGC/705 and detailed in my workpapers. As shown in Exhibit CNGC/705, adjustments were made to the following components of operating expense: 1) uncollectible expense; 2) membership fees; 3) promotional advertising; 4) interest coordination; 5) Purchased Gas Adjustment ("PGA") commodity sharing; 6) depreciation expense; 7) administrative & general ("A&G") expenses; 9) rate case costs; and 10) director and officer ("D&O") insurance premiums.

Q. How were uncollectible expenses adjusted for the Test Year?

A. Uncollectible expenses were calculated by first developing a ratio reflecting the three-year average of net write-offs to total operating revenue for the three calendar years, 2022 through 2024. This amount was applied to total Test Year operating revenue to determine a Test Year amount of $273,446. This results in an adjustment of negative $19,376 from Base Year levels.

Q. How were membership and contribution expenses adjusted for the Test Year?

A. In accordance with Commission precedent,[10] membership and contribution expenses in the Base Year were adjusted to remove 25 percent of trade organizations and

[10] *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket No. UE 435, Order No. 24-454 at 62-63 (Dec. 20, 2024); *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket No. UE 197, Order No. 09-020 at 21 (Jan. 20, 2009).

100 percent of civic / chamber of commerce expenses, resulting in a reduction of $55,535.

Q. How were promotional advertising expenses adjusted for the Test Year?

A. Promotional advertising expenses were removed from the Test Year in their entirety, reflecting a downward adjustment of $20,759.

Q. Please describe the adjustment related to interest coordination.

A. Interest coordination is a necessary adjustment due to the effect of incremental debt financing on tax expense. The adjustment of negative $110,299 was determined by applying the Company's average cost of debt to Test Year rate base, then comparing this amount to interest expense embedded in the Base Year.

Q. Please describe the adjustment related to the commodity sharing component of the PGA.

A. The PGA commodity sharing adjustment of $306,848 is necessary to remove the effect of out-of-period gas costs accrued or booked during the Base Year related to the commodity sharing component of the PGA.

Q. How was depreciation expense determined for the Test Year?

A. Test Year depreciation expense reflects depreciation rates to be in effect during the Test Year applied to forecasted monthly plant-in-service for the Test Year. This results in an adjustment of $1,435,048 over Base Year depreciation expense.

Q. Please describe the adjustment made to A&G expenses.

A. A&G expenses in the Base Year were reviewed and adjusted for expenses not appropriate for recovery through customer rates, such as costs associated with certain employee appreciation events. A&G expenses were also adjusted for costs related to Gas Technology Institute ("GTI") funding.

Q. Please discuss the adjustment to A&G related to GTI funding.

A. There are two adjustments to A&G related to GTI funding. First, $87,605 was removed from Base Year A&G to correct for an inadvertent assignment of historical Washington-specific GTI funding dollars to the Company's Oregon jurisdiction. Second, $100,000 was added to A&G to reflect expected Test Year funding amounts specific to the Company's Oregon jurisdiction. The Company's proposal to include GTI funding in Oregon rates is discussed in the Direct Testimony of Hart Gilchrist (CNGC/1200).

Q. What was the total adjustment to A&G?

A. After incorporating the two GTI-related adjustments and the removal of certain categories of expenses, the resulting adjustment to A&G is $6,913.

Q. Please describe the adjustment related to rate case costs.

A. Cascade is proposing to include rate case-related costs associated with consulting and legal services utilizing a three-year amortization period. This results in a Test Year expense amount of $464,833.

Q. Please describe the adjustment related to D&O insurance premiums.

A. Cascade is proposing to remove 50 percent of premiums associated with D&O insurance in a manner consistent with treatment in prior rate cases.[11] This results in a downward adjustment of $34,018.

Q. Please describe the determination of Test Year property taxes.

A. Test Year property taxes were calculated by estimating the amount that will be paid based on the assessment of plant-in-service during the November 2026 through October 2027 time period. To determine this amount, actual property taxes paid in the Base Year were adjusted to reflect an expected change in assessment levels. This adjusted amount was then divided by Base Year plant-in-service to develop a rate of

[11] Order No. 09-020 at 20.

property tax as a percentage of plant-in-service. This rate was then applied to Test Year plant-in-service to determine expected Test Year property taxes, resulting in an upward adjustment of $794,171.

Q. Does the Company's determination of Test Year operating expense include any broad adjustments in addition to the specific items previously discussed in your testimony?

A. Yes. The Company's determination of Test Year operating expense includes a general inflation adjustment and a conversion factor adjustment.

Q. Please describe the general inflation adjustment.

A. The Company applied a weighted forecast of CPI to Base Year non-labor O&M levels, resulting in an adjustment of $564,744. This adjustment is intended to capture general cost increases expected to be incurred after the Base Year and through the Test Year.

Q. Please describe the conversion factor adjustment.

A. The conversion factor is used to adjust net operating income for revenue sensitive items and taxes. Items included in the conversion factor include uncollectible expense, franchise fees, Commission fees, Oregon state income tax, and federal income tax. The conversion factor is 0.70628 as detailed in Exhibit CNGC/704.

D. Summary of Revenue Requirement Results

Q. What is the Company's requested rate of return ("ROR") in this case?

A. As discussed in the Direct Testimony of Tammy Nygard, the Company is requesting an overall ROR of 7.866 percent.[12]

[12] CNGC/400, Nygard.

Q. Do the results of the revenue requirement determination indicate that current rates are sufficient to allow Cascade a reasonable opportunity to earn its requested ROR?

A. No. The results of the revenue requirement determination are presented in Exhibit CNGC/702. As shown on row 33, current rates are insufficient to allow the Company to earn a reasonable rate of return for the Test Year. Base Year actual results yielded a 3.77 percent overall ROR. After adjusting rate base, operating revenues, and operating expenses as discussed previously in my testimony, the Company expects its ROR to decline to 2.92 percent in the Test Year if rates are not adjusted.

Q. Have you quantified the necessary increase in revenue requirement to allow Cascade the opportunity to earn its requested ROR?

A. Yes. As detailed in Exhibit CNGC/703, the incremental base rate revenue requirement necessary for Cascade to earn its requested ROR is $16,167,908 million.

Q. Is the Company requesting recovery of any amounts in addition to the incremental $16,167,908 quantified in your testimony and exhibits?

A. Yes. As discussed in the Direct Testimony of Zachary L. Harris, the Company is requesting recovery of $228,803 in amortization expense associated with deferred environmental remediation costs.[13]

Q. What is the overall requested rate increase reflecting the calculated increase in base rate revenue requirement and incremental environmental remediation expense?

A. The total revenue increase requested in this filing is $16.4 million, or 15.82 percent.

[13] CNGC/1100, Harris.

IV. CLASS COST-OF-SERVICE ANALYSIS

Q. Did you perform the COSS to allocate the increase in base rate revenue requirement to customer classes?

A. Yes. Following the quantification of the revenue requirement discussed previously in my testimony, I developed the COSS utilized to allocate the proposed incremental revenue requirement to customer classes.

Q. What is the purpose of a COSS?

A. A COSS determines the cost to serve each rate class based on their unique usage characteristics and system requirements. The overall objective of a COSS is to reasonably functionalize, classify, and allocate the various components of revenue requirement to rate classes based on cost causation, resulting in a fair determination of each class's revenue requirement and to inform cost-based rate design.

Q. What method was utilized to develop the COSS presented in this case?

A. Consistent with the methodology utilized in Cascade's most recent general rate case, the COSS developed for this case utilizes an LRIC study to allocate the various components of revenue requirement to customer classes.

Q. Did the Company make any adjustments to the COSS methodology in the current proceeding relative to the methodology utilized in prior cases?

A. Yes. Two adjustments were made to the COSS methodology to address issues that did not exist in the Company's most recent general rate case: 1) an adjustment related to contract-based pricing for two special contract customers; and 2) an adjustment related to the allocation of renewable natural gas ("RNG") costs to customer classes.

Q. Please describe the COSS adjustment related to the Company's two special contract customers.

A. As discussed previously in my testimony, Cascade currently provides service to two special contract customers under long-term contracts approved by the Commission.

Because the pricing for these customers is subject to the specific escalation clauses for the duration of each contract, and because the length of these contracts extends beyond the Test Year, no incremental revenue requirement in this case should be assigned to these customers; therefore, they are excluded from the LRIC study. To ensure that revenues from these customers are appropriately captured in the incremental revenue requirement determination, the revenues received from these two special contracts are applied as an offset to the revenue requirement of all other customer classes. I will discuss this adjustment in further detail when I present the results of the COSS.

Q. Please describe the COSS adjustment related to RNG investments.

A. As discussed in the Direct Testimony of Zachary L. Harris, Cascade has invested in RNG projects to comply with climate goals set forth in the CPP.[14] However, six of the Company's 34 customers taking service under Schedule 163 are categorized as emissions-intensive and trade-exposed ("EITE"), meaning they are subject to their own compliance obligations under the CPP. Because these customers are subject to their own obligations, the investments Cascade has made and will continue to make in RNG facilities should not be allocated to these customers.

Q. How is the Company proposing to address the differentiation between EITE and non-EITE customers currently embedded in Schedule 163?

A. The Company is proposing to separate EITE customers into a new Schedule 164 for the purposes of eliminating the allocation of RNG-related costs to these customers. For the allocation of all other components of revenue requirement, however, these customers will remain combined. Therefore, the COSS exhibits include a single column for all current Schedule 163 customers, both EITE and non-EITE. The

[14] CNGC/1100, Harris.

determination of rates for Schedules 163 and 164 is discussed in detail in the Direct Testimony of Cynthia A. Menhorn.[15]

Q. Please generally describe the LRIC study and how it is utilized for cost allocation.

A. LRIC studies analyze the cost of providing service to a utility's customer classes by quantifying the incremental cost of investment and operating expenses necessary to provide continuing service to customers. These studies—also referred to as "marginal cost" studies—provide a more forward-looking approach to cost allocation than embedded cost studies, which generally allocate costs to customer classes based on historic information. The primary components of the LRIC study are the cost of incremental plant investments and incremental O&M expenses. These components are summed to determine total long-run incremental costs by rate class, which are then utilized to allocate the requested revenue requirement to customer classes.

Q. Has the Company utilized this methodology in previous general rate cases?

A. Yes. The Company utilized this methodology in its four most recent general rate cases before this Commission, dockets UG 287, UG 305, UG 347, and UG 390.

A. Incremental Plant Investment Costs

Q. What are the components that comprise the Company's incremental plant investment included in the LRIC study?

A. Incremental plant investment included in the LRIC study is comprised of three components: 1) the cost to install distribution mains; 2) the cost to provide a service line; and 3) the cost to provide a meter and regulator to serve new customers.

[15] CNGC/800, Menhorn.

1. Distribution Mains

Q. Please briefly describe the distribution main components of incremental plant investment.

A. The distribution main components include the Company's investments to 1) connect new customers to the system; and 2) invest in long-term system main replacement.

Q. What was the first step in determining the cost of distribution mains utilized in the LRIC study?

A. The first step in determining the cost of distribution mains was to utilize available accounting data to determine a cost-per-foot for each material type (plastic or steel) and pipe diameter. These values were calculated utilizing 10 years of accounting data (2015 through 2024) escalated to 2025 dollars utilizing the Handy Whitman Index of Public Utility Construction Costs ("Handy Whitman Index"). When feasible, only growth-related projects were utilized in the cost-per-foot determinations to emphasize the incremental nature of the LRIC study. However, for large diameter steel (greater than and equal to four inches), both growth and non-growth projects were utilized given a lack of sufficient growth projects to form a robust dataset.

Q. How did the Company utilize the cost-per-foot data to determine the incremental cost of mains for each customer class?

A. The determination of distribution main incremental costs by rate class was calculated utilizing two methods. For customer classes with a relatively large number of customers (Schedules 101, 104, and 105), the cost-per-foot was applied to the typical main extension per customer, taking into account the typical material, diameter, and length of extension required for each customer class to determine the class-specific average incremental cost of a distribution main extension. This cost-per-customer was then applied to customer counts to determine the total incremental distribution mains investment by rate class. This calculation is presented on rows 24 through 29 of Exhibit CNGC/708.

For customer classes with a relatively small number of customers (Schedules 111, 163, and 170) geographic information system ("GIS") data was utilized to identify material, size, and length for each individual customer. Cost-per-foot values were then applied to this data to determine the total incremental distribution mains investment by class as detailed on row 29 of Exhibit CNGC/708.

Q. How did the Company determine the incremental cost of distribution mains for long-term system replacement investments?

A. The Company estimated the long-term distribution main replacement costs utilizing the previously discussed cost-per-foot by material type and size. These per-foot costs were applied to current mileage of installed mains on Cascade's system to develop a total system incremental cost. The Company then subtracted from this total the class-specific customer mains investment detailed previously in my testimony to determine the remaining level of system replacement investment. This investment was then separated into capacity and commodity components using Cascade's Oregon load factor, and these components were then allocated to the appropriate rate classes using design day demand and annual throughput, respectively. These calculations are detailed on rows 31 through 44 of Exhibit CNGC/708.

Q. How were the class-specific distribution main investment amounts utilized to inform the results of the LRIC study?

A. After determining the distribution main investment amounts by class for each of these components, an annual carrying charge was applied to convert the investment amounts to commensurate annual revenue requirement amounts. The resulting annual carrying costs for the three components of distribution mains (customer-specific investment, capacity-related system investment, and commodity-related system investment) ultimately serve as the allocation basis for the corresponding components of revenue requirement as I will discuss later in my testimony.

Q. Are you presenting an exhibit that details the derivation of the annual carrying charges utilized in the LRIC study?

A. Yes. The derivation of the annual carrying charges is detailed in CNGC/710, with a separate carrying charge calculation for distribution mains, service lines, and meters.

2. Service Lines

Q. How did the Company determine the incremental cost of installing new services?

A. Similar to the quantification of distribution mains investment, different methodologies were utilized for rate classes with a relatively large number of customers (Schedules 101, 104, and 105) and classes with a relatively small number of customers (Schedules 111, 163, and 170).

For Schedules 101, 104, and 105, the Company examined ten years of accounting data to determine the cost-per-service installation based on material (plastic) and diameter (less than or equal to 1.25 inches and 2 inches). These costs were escalated to 2025 dollars utilizing the Handy Whitman Index and assigned to each schedule based on typical service installation characteristics. The cost-per-service installation was then multiplied by the number of customers in each class to determine a total incremental service installation cost by class. These calculations are detailed on rows 7 through 10 of Exhibit CNGC/708.

For Schedules 111, 163, and 170, GIS data was used to identify customer-specific service installation data. The Company then applied the cost-per-foot of pipe installation discussed previously in my testimony to the material, diameter, and length data determined through GIS to develop a class-specific total incremental investment amount for service installations. These values are contained on row 10 of Exhibit CNGC/708.

Q. How were the class-specific service installation investment amounts utilized to inform the results of the LRIC study?

A. After determining the service installation investment amounts by class, an annual carrying charge was applied to convert the investment amounts to commensurate annual revenue requirement amounts. In the same manner as distribution mains investment, the resulting annual carrying costs ultimately serve as the allocation basis for the corresponding components of revenue requirement as I will discuss later in my testimony.

3. Meters and Regulators

Q. How did the Company determine the incremental cost of meters and regulators?

A. For Schedules 101, 104, and 105, a weighted average meter cost was calculated for each class based on currently installed meter counts multiplied by the current cost of each meter type. Total meter costs are comprised of the cost of the meter, the Encoder Transmitter Receiver, the regulator, and capitalized installation costs. For Rate Schedules 111, 163, and 170, the Company surveyed the existing equipment installed for each customer and applied current costs to each component. The resulting meter costs by class are contained on row 17 of Exhibit CNGC/708.

Q. How were the class-specific meter investment amounts utilized to inform the results of the LRIC study?

A. After determining total incremental meter investment by class, an annual carrying charge was applied to convert the investment amounts to commensurate annual revenue requirement amounts. In the same manner as distribution mains and service installation investments, the resulting annual carrying costs ultimately serve as the allocation basis for the corresponding components of revenue requirement as I will discuss later in my testimony.

B. Incremental O&M Expenses

Q. Please identify the categories of gas supply-related O&M expenses utilized in the LRIC study.

A. The overall category of gas supply O&M expenses includes the salaries and benefits of personnel who contribute to three primary areas: 1) Resource Planning; 2) Gas Supply; and 3) Gas Control. These costs were further delineated between core and non-core expenses.

Q. Please describe each of the three primary functions contributing to overall gas supply-related O&M.

A. The Resource Planning function includes monthly, seasonal, and annual gas resource planning; supply resource modeling and optimization; market intelligence gathering, analysis, and internal reporting; Integrated Resource Plan development; and Canadian and U.S. pipeline and storage operational, tolls and tariffs, and shipper-related activities.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies that includes day-to-day storage activities; gas supply reporting such as commodity and closing price reporting; and processing supplier invoicing, as well as updating and maintaining North American Energy Standards Board contracts. Additionally, the Gas Supply function includes activities related to non-core customers, such as imbalance “packing” or “drafting” that affects the overall system balance position.

The Gas Control function provides 24-hour daily monitoring and management of the flow of gas on Cascade’s pipeline system in Oregon. This monitoring is accomplished by the electronic monitoring of various points on the system through supervisory control and data acquisition and Metretek measuring equipment.

Q. How did the Company separate total gas supply O&M into each of these categories?

A. The first step in assigning gas supply O&M to each of these categories was to develop a list of positions that comprises overall gas supply O&M labor. Allocation percentages were then developed for each position based on the corresponding business unit, taking into account hours allocated to Cascade, hours allocated to Oregon, and hours allocated to each of the three functions previously discussed. Percentages were also applied to further separate these positions into core and non-core functions. Lastly, the resulting allocation percentages for the three categories, separated between core and non-core, were applied to fully-loaded gas supply labor costs to develop incremental O&M costs for each of these six components (i.e., three categories separated between core and non-core).

Q. How were incremental O&M costs related to each of these components assigned to customer classes?

A. Expenses related to the Resource Planning function were allocated using a peak-and-average allocation factor. Expenses related to the Gas Supply function were allocated among the core and non-core classes using sales and transportation volumes. Expenses related to the Gas Control function were allocated using sales or transportation volumes as well. The results of the gas supply-related O&M expense determination are contained on rows 15 through 31 of Exhibit CNGC/709.

Q. What categories of customer-related expenses were considered in the LRIC study?

A. The LRIC study includes customer-related expenses stemming from three categories: 1) meter reading; 2) customer accounts records and collection; and 3) uncollectible expenses.

Q. How were class-specific meter reading costs developed for the LRIC?

A. Meter reading expenses were developed for each customer class by first compiling a list of positions that actively participate in meter reading activities. The annual cost of labor was calculated utilizing current wage rates and loading, then applying the percentage of time each position spends on meter reading activities. The resulting meter reading costs were assigned to each customer class based on customer counts.

Q. How were class-specific customer records, billing, and collections costs developed for the LRIC?

A. Total customer records, billing, and collections costs were assigned to customer classes based on customer counts.

Q. How were class-specific uncollectible expenses for each rate class developed for the LRIC?

A. Class-specific uncollectible expenses were developed by calculating a three-year average of net write-offs for residential, commercial, and industrial customers. These amounts were directly assigned to the respective customer classes.

C. LRIC Study Results

Q. How are the results of the LRIC Study utilized to apportion revenue requirement to customer classes?

A. The LRIC study calculates incremental costs by rate class for each of the components discussed previously in my testimony. These components correspond to the functionalized categories of revenue requirement presented in Exhibit CNGC/707.

Q. Please describe the functionalization process as presented in Exhibit CNGC/707.

A. Before assigning the revenue requirement to rate schedules, it must first be divided between functional categories that align with the allocation bases developed through the LRIC study. There are four primary functional categories listed on Exhibit CNGC/707: 1) Gas Scheduling & Planning; 2) Meter Reading & Billing; 3) Meters & Services; and 4) System Core Mains. Due to the separate treatment of RNG-related costs there are two additional columns, one for capital-related RNG costs and another for expense-related RNG costs. Each component of revenue requirement is directly assigned to a functional category when possible, and if direct assignment is not possible a reasonable allocation factor is utilized (e.g., general plant is functionalized based on the aggregate of all other plant functionalization).

Q. Are you sponsoring an exhibit that details the allocation of functionalized revenue requirement to customer classes utilizing the results of the LRIC study?

A. Yes. Exhibit CNGC/706 details the results of the class allocation process based on the results of the LRIC study.

Q. Please summarize the results of the cost allocation process detailed in Exhibit CNGC/706.

A. The LRIC study results are summarized on rows 32 through 38 of Exhibit CNGC/706, which indicate total incremental costs for each class by function. The results of the functionalized revenue requirement are contained in the “Total” column of rows 43 through 46. The functionalized revenue requirement on rows 43 through 46 is then allocated to rate classes in relative proportion to the incremental costs by class detailed on rows 33 through 37 to determine class-specific revenue requirement amounts.

Q. Are there any reductions to revenue requirement that were applied following the LRIC-based allocation you just described?

A. Yes. As previously mentioned, special contract revenues not subject to the rate increase requested in this case were applied to customer classes to serve as an offset to the requested revenue requirement. This revenue offset was apportioned to customer classes based on a peak-and-average allocation factor. Additionally, a revenue requirement offset is applied to customer classes related to “Other Operating Revenues” listed on row 47. This amount reflects revenues associated with late fees and disconnect / reconnect fees. These amounts were apportioned to customer classes in proportion to existing revenue collection.

Q. How were RNG-related costs incorporated into the class allocation process?

A. Given the special circumstances surrounding RNG investments as discussed previously in my testimony, revenue requirement related to these investments was separated from all other components of revenue requirement as detailed in Exhibit CNGC/707. These costs were then separately allocated to customer classes on the basis of throughput (excluding EITE customer sales) as detailed on rows 52 and 53 of Exhibit CNGC/706. In addition to RNG-related costs, CPP-related labor was also separately allocated to non-EITE customers utilizing non-EITE throughput.

Q. What were the ultimate results of the COSS utilizing the LRIC methodology detailed in your testimony?

A. The ultimate results of the COSS are summarized on rows 56 and 58 of Exhibit CNGC/706. Row 56 contains the final revenue requirement targets for each rate schedule based on the COSS methodology. Row 58 contains the relative revenue-to-cost ratio for each customer class, which indicates the adequacy of current rates in recovering the cost-of-service for each customer class. These results serve as key considerations in the development of rate design, which is discussed in complete detail in the Direct Testimony of Cynthia A. Menhorn.[16]

Q. In addition to the values discussed in the previous question, were the COSS results utilized to inform any additional components of the Company's proposed rate design?

A. Yes. As discussed in the Direct Testimony of Zachary L. Harris,[17] Cascade is proposing a firm transport service offering in addition to the existing interruptible transport service offered through Schedule 163. The results of the COSS were utilized to develop the Daily Contract Demand Charge included in these proposed schedules.

Q. How were the results of the COSS utilized to develop the Daily Contract Demand Charge included in the proposed firm transport schedules?

A. To determine cost-based rates for firm transport service, total revenue requirement for the "Mains" category of $35,312,116 was divided by peak-day therms for existing customers of 841,184, to determine a cost-per-peak day therm of $41.98. This value was then divided by 365 and rounded to the nearest cent to determine the proposed Daily Contract Demand Charge of 12 cents per therm.

V. CONCLUSION

Q. Please summarize your testimony.

A. The Company's revenue requirement in this case was developed using a historical Base Year of the twelve months ended June 2025 and a fully forecast Test Year for the twelve months ending October 2027. Rate base, operating revenues, and operating expenses were adjusted to reflect amounts commensurate with the rate effective period requested in this case. As a result of the revenue requirement

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[16] CNGC/800, Menhorn.
[17] CNGC/1100, Harris.

development discussed in my testimony, the Company is requesting an increase to base rate revenue of $16,167,908, or 15.60 percent over current rates.

Following the determination of Test Year revenue requirement, the Company developed a LRIC study to apportion the requested revenue increase to customer classes. Applying the results of the LRIC study to the Company's functionalized revenue requirement resulted in revenue targets by functional category for use in developing cost-based rates to meet the Company's rate design objectives.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

WITNESS QUALIFICATIONS OF MATTHEW LARKIN

EXHIBIT 701

November 2025

Matthew Larkin

Career Overview

Regulatory Affairs expert with nearly 17 years of experience working in the regulated utility industry. Prior to joining MCR, Matthew held various positions in the Regulatory Affairs and Finance departments at Idaho Power Company, a vertically integrated electric utility serving customers in southern Idaho and eastern Oregon, most recently serving as the Revenue Requirement Senior Manager from 2016 to 2025. In-depth experience in a broad array of regulatory areas, including revenue requirement development, class cost-of-service studies, and rate design. Served as testimony sponsor before the Idaho Public Utilities Commission and the Public Utility Commission of Oregon and contributed to transmission formula rate filings before the Federal Energy Regulatory Commission.

Career History

MCR Performance Solutions, LLC

MCR provides consulting services to the utility industry, namely natural gas, electric and water utilities. The firm has extensive experience working with investor owned utilities, G&T cooperatives and public power agencies. MCR combines its industry knowledge with its unique elements of economic analysis, regulatory process, strategic insight, organizational change and information management. Since 1999, MCR has assisted clients in navigating the challenges of a complex energy environment and working with them to create a new future.

Director, Regulatory Services

Responsible for performing analyses and managing consulting agreements with utilities throughout the country. The Regulatory Services practice covers a broad array of regulatory matters, including all facets of rate case development, policy support, and strategy development. Engagements include general rate case support, strategic advisement for green power initiatives, and shared services studies.

Idaho Power Company

Idaho Power Company is a vertically integrated electric utility serving approximately 650,000 customers throughout its 24,000-square-mile service area in southern Idaho and eastern Oregon. It is regulated by the Idaho Public Utilities Commission and the Public Utility Commission of Oregon, as well as the Federal Energy Regulatory Commission.

Revenue Requirement Senior Manager, Regulatory Affairs Department

Served in senior leadership role over all revenue requirement matters at Idaho Power. Filings included power cost adjustments, general rate cases, and annual transmission tariff rate filings, among others. Prepared and reviewed filings while coordinating with business units across the company. Represented Idaho Power as an expert witness sponsoring testimony both in writing and at live hearings before state regulatory agencies.

Budget and Revenue Manager, Finance Department

Led team responsible for financial support of regulatory filings as well as the enterprise-wide budgeting process. Supported integration of financial information into regulatory filings. Oversaw discovery and audit request response process, coordinating with respondents throughout multiple business units covering a broad array of subject matter.

Regulatory Analyst (I, II, Senior), Regulatory Affairs Department

Developed complex analyses in support of the company's regulatory efforts, including cost-of-service studies, jurisdictional separation studies, and the determination of Idaho Power's transmission tariff rates as part of its Open Access Transmission Tariff. Prepared analyses, drafted testimony, and ensured tariffs accurately complied with commission orders. Testified in writing and in person before state regulatory agencies.

Education

Master of Business Administration – University of Oregon

Bachelor of Business Administration (magna cum laude) with a concentration in Finance – University of Oregon

Selected Rates and Regulatory Experience at Idaho Power Company

State	Case Number	Date Filed	Issue / Description
ID	IPC-E-25-16	5/30/2025	General Rate Case - Revenue Requirement Testimony
ID	IPC-E-24-07	2/15/2024	General Rate Case – Revenue Requirement Testimony
OR	UE 426	12/15/2023	General Rate Case – Revenue Requirement Testimony
ID	IPC-E-23-11	3/31/2023	General Rate Case – Revenue Requirement Testimony
ID	IPC-E-21-17	6/3/2021	Power Plant Cost Recovery Mechanism
OR	UE 382	8/26/2020	Request for Amortization of Deferred Revenues
ID	IPC-E-19-14	4/4/2019	Approval of Power Purchase Agreement
ID	IPC-E-12-27	11/30/2012	Cost-of-Service / Rate Design Testimony for Distributed Generation
OR	UE 233	7/29/2011	General Rate Case – Cost-of-Service, Revenue Forecasting Testimony
ID	IPC-E-11-08	5/24/2011	General Rate Case – Cost-of-Service, Revenue Forecasting Testimony

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

REVENUE REQUIREMENT SUMMARY

EXHIBIT 702

November 2025

Cascade Natural Gas Corporation
TEST YEAR DEVELOPMENT SUMMARY SHEET
UG 525
Twelve Months Ending October 31, 2027

	SUMMARY SHEET	Base Period Jul-24 through Jun-25 (1)	Summary of Adjustments (2)	Test Year Adjusted Total (3)	Requested Revenue Increase (4)	Adjusted Results After Proposed Revenues (5)
	Operating Revenues					
1	Natural Gas Sales	96,334,386	1,881,118	98,215,504	15,377,719	113,593,224
2	Gas Transportation Revenue	5,269,618	171,715	5,441,332	790,189	6,231,521
3	Other Operating Revenues	665,209	(347,922)	317,287		317,287
4	SUBTOTAL	102,269,212	1,704,911	103,974,123	16,167,908	120,142,032
5	LESS: Nat. Gas/Production Costs	54,779,618	(306,848)	54,472,770		54,472,770
6	**OPERATING MARGIN**	47,489,594	2,011,759	49,501,353	16,167,908	65,669,262
7						
8	**Operating Expenses**					
9	Production	221,005	13,025	234,030		234,030
10	Transmission	20,700	1,220	21,920		21,920
11	Distribution	7,140,213	192,214	7,332,428		7,332,428
12	Customer Accounts	2,466,454	129,545	2,595,999	42,379	2,638,378
13	Customer Service	193,914	11,429	205,342		205,342
14	Sales	154,356	(11,662)	142,695		142,695
15	Administrative and General	10,069,077	417,691	10,486,768		10,486,768
16	Depreciation & Amortization	10,862,037	1,417,469	12,279,506		12,279,506
17	Regulatory Debits	(9,367)	0	(9,367)		(9,367)
18	Taxes Other Than Income	9,054,369	840,802	9,895,171	442,208	10,337,379
19	State & Federal Income Taxes	(48,473)	(376,882)	(425,355)	4,235,124	3,809,769
20	Reconciliation Adjustment					29,094
21	**Total Operating Expenses**	40,124,286	2,634,853	42,759,138	4,719,712	47,507,944
22	**Net Operating Revenues**	7,365,308	(623,093)	6,742,215	11,448,197	18,161,318
23						
24	**Rate Base**					
25	Total Plant in Service	369,605,988	58,565,017	428,171,005		428,171,005
26	Total Accumulated Depreciation	(149,059,378)	(21,819,937)	(170,879,315)		(170,879,315)
27	Contributions in Aid of Construction	0	0	0		0
28	Customer Adv. For Construction	(152,235)	0	(152,235)		(152,235)
29	Deferred Accumulated Income Taxes	(28,729,364)	(1,442,827)	(30,172,192)		(30,172,192)
30	Deferred Debits	0	0	0		0
31	Working Capital Allowance	3,916,503	0	3,916,503		3,916,503
32	**TOTAL RATE BASE**	195,581,514	35,302,252	230,883,766	0	230,883,766
33	**Rate of Return**	3.77%		2.92%		7.866%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

REVENUE REQUIREMENT CALCULATION

EXHIBIT 703

November 2025

Cascade Natural Gas Corporation
REVENUE REQUIREMENT CALCULATION
UG 525
Twelve Months Ending October 31, 2027

1	Adjusted Rate Base	$230,883,766
2	Rate of Return	7.866%
3		
4	Required Return (ln 1 x ln 2)	$18,161,317
5	Adjusted Net Income	$6,742,215
6		
7	Required Net Income Increase (ln 4 - ln 5)	$11,419,102
8		
9	Conversion Factor	0.70628
10		
11	Revenue Increase Required (ln 7 / ln 9)	**$16,167,908**
12		
13	Test Year Adjusted Revenue	$103,656,837
14		
15	Overall Revenue Increase	**15.598%**
16		
17	Environmental Remediation Revenue Increase	$228,803
18		
19	Total Revenue Increase	**$16,396,711**
20		
21	Total Increase	**15.818%**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

CONVERSION FACTOR

EXHIBIT 704

November 2025

Cascade Natural Gas Corporation
CONVERSION FACTOR CALCULATION
UG 525
Twelve Months Ended October 31, 2027

1	Revenues	1.00000
2	Operating Revenue Deductions	
3	Uncollectible Accounts	0.00262
4	Taxes Other - Franchise	0.02285
5	OPUC Fees	0.00450
6		
7	State Taxable Income	0.97003
8		
9	State Income Tax	0.07600
10		
11	Federal Taxable Income	0.89403
12		
13	Federal Income Tax @ 21%	0.18775
14		
15	Total Income Taxes	0.26375
16		
17	Total Revenue Sensitive Costs	0.29372
18		
19		
20	Net-to-Gross Factor	**0.70628**
21		
22		
23		
24	Combo-State & Federal Income Tax	
25	State	7.60%
26	Federal	21.00%
27		
28	State and Federal Effective Tax Rate	0.27004

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

SUMMARY OF ADJUSTMENTS

EXHIBIT 705

November 2025

Cascade Natural Gas Corporation
TEST YEAR EXPENSE AND REVENUE ADJUSTMENTS
UG 525
Twelve Months Ended October 31, 2027

			Uncollectible Expense (a)	Removal 50% Membership Fees (b)	Promotional Advertising Adjustment (c)	Interest Coordination Adjustment (d)	PGA Commodity Sharing Adj. (e)	CPP Labor Adjustment (f)	Revenue Adjustment (g)	Wage Adjustments (h)	Incentive Comp Adj (i)	Plant Additions (j)	Inflation Factor Adj (k)	A&G Adjustment (l)	Rate Case Costs (m)	D&O Insurance Premiums adj (n)	**Total Adjustments (Base Rates) (q)**
1	1	**Operating Revenues**															
2	2	Natural Gas Sales							$1,881,118				$0	$0			1,881,118
3	3	Gas Transportation Revenue							171,715				0	0			171,715
4	4	Other Operating Revenues							(347,922)				0	0			(347,922)
5	5	SUBTOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,704,911**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,704,911**
6	6	LESS: Nat. Gas/Production Costs					(306,848)										($306,848)
7	7	placeholder					0										$0
8	8	**OPERATING MARGIN**	**$0**	**$0**	**$0**	**$0**	**$306,848**	**$0**	**$1,704,911**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	$2,011,759
9	9																$0
10	10	**Operating Expenses**															$0
11	11	Production											13,025				$13,025
	12	Transmission											1,220				$1,220
12	13	Distribution											192,214				$192,214
13	14	Customer Accounts	($20,288)				$0		$4,469				145,364				$129,545
14	15	Customer Service											11,429				$11,429
15	16	Sales			(20,759)								9,097				($11,662)
16	17	Administrative and General		(49,046)				58,926		775,994	(1,060,828)		254,916	6,913	464,833	(34,018)	$417,691
17	18	Depreciation & Amortization										1,417,469					$1,417,469
18	19	Regulatory Debits															$0
19	20	Taxes Other Than Income							46,631			794,171					$840,802
20	21	State & Federal Income Taxes	5,478	13,244	5,606	(106,848)	82,861	(15,912)	446,595	(209,549)	286,466	(597,231)	(169,387)	(1,867)	(125,524)	9,186	($376,882)
21	22	**Total Operating Expenses**	(14,809)	(35,802)	(15,153)	(106,848)	82,861	43,014	497,695	566,445	(774,362)	1,614,409	457,879	5,046	339,310	(24,832)	$2,634,853
22	23	**Net Operating Revenues**	$14,809	$35,802	$15,153	$106,848	$223,987	($43,014)	$1,207,216	($566,445)	$774,362	($1,614,409)	($457,879)	($5,046)	($339,310)	$24,832	($623,093)
	24																

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

COSS SUMMARY OF RESULTS

EXHIBIT 706

November 2025

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
COSS Summary of Results

Line No.	Description	Total	101 Residential Service	104 Commercial Service	105 Industrial Service	111 Large Volume Service	163 General Distribution Interruptible	170 Interruptible
			core	core	core	core	non-core	core
1	**Billing Determinants**							
2	Peak Day Forecast	84,118	49,468	28,961	2,368	1,566	-	1,756
3	Customer Count	89,119	78,223	10,682	160	16	34	4
4	Throughput (All)	15,126,409	5,555,029	3,405,492	322,090	274,542	5,308,998	260,259
5	Throughput (Excl. EITE)	10,886,175	5,555,029	3,405,492	322,090	274,542	1,068,765	260,259
6								
7	**O&M Costs**							
8	*Gas Supply Related*							
9	Gas Planning	$ 132,429	$ 61,375	$ 36,583	$ 3,177	$ 2,362	$ 26,486	$ 2,447
10	Gas Supply	$ 194,919	$ 110,292	$ 67,614	$ 6,395	$ 5,451	$ -	$ 5,167
11	Gas Control	$ 158,915	$ 62,944	$ 38,587	$ 3,650	$ 3,111	$ 47,675	$ 2,949
12								
13	*Customer Related*							
14	Meter Reading	$ 501,480	$ 440,142	$ 60,104	$ 900	$ 99	$ 210	$ 25
15	Customer Account Records And Collection	$ 1,578,195	$ 1,385,241	$ 189,164	$ 2,832	$ 285	$ 602	$ 71
16	Uncollectible	$ 368,918	$ 281,055	$ 86,256	$ 1,607	$ -	$ -	$ -
17	Subtotal: O&M Costs	$ 2,934,857	$ 2,341,050	$ 478,309	$ 18,560	$ 11,308	$ 74,972	$ 10,658
18								
19	**Customer Investment Carrying Costs**							
20	Meter	$ 8,919,561	$ 5,879,597	$ 2,395,027	$ 162,825	$ 122,528	$ 301,719	$ 57,864
21	Service	$ 39,063,155	$ 33,832,037	$ 4,619,987	$ 166,775	$ 63,562	$ 311,778	$ 69,017
22	Mains	$ 17,509,896	$ 8,962,122	$ 1,223,837	$ 1,839,071	$ 767,987	$ 4,063,802	$ 653,077
23	Subtotal: Customer Investment Carrying Costs	$ 65,492,611	$ 48,673,756	$ 8,238,851	$ 2,168,671	$ 954,078	$ 4,677,299	$ 779,957
24								
25	**System Core Main Carrying Costs**							
26	Capacity	$ 101,979,810	$ 59,971,587	$ 35,109,980	$ 2,870,804	$ 1,898,514	$ -	$ 2,128,925
27	Commodity	$ 47,935,830	$ 17,603,974	$ 10,792,059	$ 1,020,707	$ 870,027	$ 16,824,300	$ 824,764
28	Subtotal: System Core Main Carrying Costs	$ 149,915,640	$ 77,575,561	$ 45,902,039	$ 3,891,510	$ 2,768,540	$ 16,824,300	$ 2,953,689
29								
30	**LRIC - Distribution**	$ 218,343,108	$ 128,590,367	$ 54,619,198	$ 6,078,742	$ 3,733,926	$ 21,576,571	$ 3,744,304
31								
32	**Functional Cost Assignment By LRIC**							
33	Scheduling & Planning	$ 486,264	$ 234,611	$ 142,785	$ 13,221	$ 10,924	$ 74,160	$ 10,563
34	Meter Reading, Billing, Etc.	$ 2,448,593	$ 2,106,439	$ 335,524	$ 5,339	$ 384	$ 812	$ 96
35	Meters & Services	$ 47,982,716	$ 39,711,634	$ 7,015,014	$ 329,600	$ 186,091	$ 613,497	$ 126,880
36	Mains Extensions	$ 17,509,896	$ 8,962,122	$ 1,223,837	$ 1,839,071	$ 767,987	$ 4,063,802	$ 653,077
37	System Core Mains	$ 149,915,640	$ 77,575,561	$ 45,902,039	$ 3,891,510	$ 2,768,540	$ 16,824,300	$ 2,953,689
38	**Total**	$ 218,343,108	$ 128,590,367	$ 54,619,198	$ 6,078,742	$ 3,733,926	$ 21,576,571	$ 3,744,304

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
COSS Summary of Results

Line No.	Description	Total	101 Residential Service	104 Commercial Service	105 Industrial Service	111 Large Volume Service	163 General Distribution Interruptible	170 Interruptible
			core	core	core	core	non-core	core
39								
40	**Non-Gas Revenue At Current Rates**	$ 43,152,930	$ 27,556,082	$ 10,829,051	$ 847,462	$ 470,192	$ 3,113,648	$ 336,496
41								
42	**Non-Gas Revenue Requirement Excl. RNG**							
43	Scheduling And Planning	$ 554,084	$ 267,333	$ 162,699	$ 15,065	$ 12,447	$ 84,504	$ 12,036
44	Meter Reading & Billing	$ 6,324,891	$ 5,441,081	$ 866,682	$ 13,791	$ 993	$ 2,097	$ 247
45	Meters & Services	$ 18,442,252	$ 15,263,245	$ 2,696,235	$ 126,682	$ 71,524	$ 235,799	$ 48,767
46	Mains	$ 35,312,116	$ 18,251,868	$ 9,939,430	$ 1,208,651	$ 745,897	$ 4,405,559	$ 760,711
47	Other Operating Revenues	$ (317,287)	$ (202,609)	$ (79,622)	$ (6,231)	$ (3,457)	$ (22,893)	$ (2,474)
48	Schedule 906 Revenue Offset	$ (1,129,596)	$ (539,559)	$ (321,607)	$ (27,926)	$ (20,766)	$ (198,230)	$ (21,508)
49	**Total LRIC Based Non-Gas Rev Req Excl. RNG**	$ 59,186,461	$ 38,481,358	$ 13,263,817	$ 1,330,032	$ 806,639	$ 4,506,835	$ 797,778
50								
51	**RNG Revenue Requirement**							
52	RNG Capital	$ 175,730	$ 89,672	$ 54,973	$ 5,199	$ 4,432	$ 17,252	$ 4,201
53	RNG Expense	$ 111,382	$ 56,837	$ 34,843	$ 3,295	$ 2,809	$ 10,935	$ 2,663
54	**Total RNG Revenue Requirement**	$ 287,112	$ 146,508	$ 89,816	$ 8,495	$ 7,241	$ 28,188	$ 6,864
55								
56	**Total LRIC Based Non-Gas Rev Req Incl. RNG**	$ 59,473,573	$ 38,627,867	$ 13,353,634	$ 1,338,527	$ 813,880	$ 4,535,023	$ 804,642
57								
58	**Revenue To Cost Ratio**	0.73	0.72	0.82	0.64	0.58	0.69	0.42
59								
60	**Incremental Revenue Requirement from COSS Results**	$ 16,320,643						
61	**Incremental Revenue Requirement from Larkin CNGC/703**	$ 16,167,908						
62	**Revenue Requirement Adjustment to COSS Results**	$ (152,735)						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

FUNCTIONALIZATION OF REVENUE REQUIREMENT

EXHIBIT 707

November 2025

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Functionalization of Revenue Requirement

No.	FERC	Description	Test Year Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains	RNG Capital	RNG Expense
1		**Plant In Service**								
2		Intangible Plant	$18,973,307	Plant	$0	$0	$6,993,429	$11,979,879		
3		Production Plant	$0	DA				$0		
4		Storage Plant	$0	DA				$0		
5		Transmission Plant	$5,908,136	DA				$5,908,136		
6		Distribution Plant		DA				$0		
7	374	Land And Land Rights	$542,893	DA				$542,893		
8	374	Land And Land Rights - RNG	$25,268	RNGPlt					$25,268	
9	375	Structures And Improvements	$520,274	DA				$520,274		
10	375	Structures And Improvements - RNG	$97,927	RNGPlt					$97,927	
11	376	Mains	$221,043,894	DA				$221,043,894		
12	376	Mains - RNG	$758,185	RNGPlt					$758,185	
13	377	Compressor Station	$0	DA				$0		
14	378	M & R Station Equipment	$14,230,789	DA				$14,230,789		
15	378	M & R Station - RNG	$1,075,846	RNGPlt					$1,075,846	
16	380	Services	$99,868,573	DA			$99,868,573			
17	381	Meters	$34,329,726	DA			$34,329,726			
18	382	Meter Install - Rolled into Account 381	$0	DA			$0			
19	383	House Regulator & Install.	$4,266,298	DA			$4,266,298			
20	385	Industrial M & R Station Equipment	$2,950,022	DA			$2,950,022			
21	385	Industrial M & R - RNG	$392,246	RNGPlt					$392,246	
22		General Plant	$23,187,622	Plant	$0	$0	$8,546,796	$14,640,827		
23		Subtotal Plant In Service	$ 428,171,005		$0	$0	$156,954,843	$268,866,691	$2,349,472	
24										
25		**Accumulated Depreciation**								
26		Intangible Plant	($13,594,920)	Plant	$0	$0	($5,010,993)	($8,583,928)		
27		Production Plant	$0	DA				-		
28		Storage Plant	$0	DA				-		
29		Transmission Plant	($3,999,502)	DA				(3,999,502)		
30		Distribution Plant	($141,526,888)	DistPlant	-	-	($52,981,708)	($88,545,180)		
31		Distribution Plant - RNG	($115,432)	RNGPlt					($115,432)	
32		General Plant	($11,642,573)	Plant	-	-	($4,291,371)	($7,351,202)		
33		Subtotal Accumulated Depreciation	($170,879,315)		$ -	$ -	$ (62,284,071)	$ (108,479,812)	$ (115,432)	$ -
34										

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Functionalization of Revenue Requirement

No.	FERC	Description	Test Year Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains	RNG Capital	RNG Expense
35		**Other Ratebase Items**								
36		Contributions In Aid Of Construction	$ -				-			
37		Customer Adv. For Construction	(152,235)	DA			(152,235)			
38		Accumulated Deferred Income Taxes	(30,172,192)	Plant	$0	$0	($11,121,259)	($19,050,933)		
39		Deferred Debits	-	DA			-			
40		Working Capital Allowance	3,916,503	Plant	-	-	$1,443,596	$2,472,907		
41		Subtotal Other Ratebase	$ (26,407,924)		$ -	$ -	$ (9,829,899)	$ (16,578,025)	$ -	$ -
42										
43		**Total Ratebase**	$ 230,883,766		$ -	$ -	$ 84,840,873	$ 143,808,853	$ 2,234,040	
44										
45										
46		**Rate Of Return**	7.8660%							
47										
48		**Return On Ratebase**	$ 18,161,317		$ -	$ -	$ 6,673,583	$ 11,312,004	$ 175,730	
49										

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Functionalization of Revenue Requirement

No.	FERC	Description	Test Year Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains	RNG Capital	RNG Expense
50		**Operating Expenses**								
51		Production	$ 234,030	DA	$ 234,030					
52		Transmission	$ 21,920	DA	$ 21,920					
53		Distribution								
54	870	Operation Supervision & Engineering	958,710	OpEx	31,726	-	93,331	833,652		
55	871	Distribution Load Dispatching	81,977	OpEx	81,977					
56	872	Compressor Station	-	OpEx				-		
57	874	Mains And Services Expenses	1,690,403	OpEx				1,690,403		
58	875	Meas. & Reg. Station Expenses	202,855	OpEx				202,855		
59	876	Meas. & Reg. Station Expenses - Ind	210,197	OpEx				210,197		
60	877	Maintenance of Mains	50,603	DA				50,603		
61	878	Meter & House Regulator Expenses	15,716	OpEx			15,716			
62	879	Customer Installations Expenses	225,441	OpEx			225,441			
63	880	Other Expenses	1,211,749	OpEx	40,100	-	117,965	1,053,684		
64	881	Rents	45,015	Plant	$0	$0	$16,592	$28,423		
65	885	Maint. Supervision & Engineering	359,669	MaintExp	-	-	194,606	165,063		
66	886	Maint. Of Structures & Improvements	202	MaintExp				202		
67	887	Maint. Of Mains	307,710	MaintExp				307,710		
68	888	Maint. Of Compressor Station Equip.	-	MaintExp				-		
69	889	Maint. Of Meas. & Reg. Station Expenses-General	141,463	MaintExp				141,463		
70	890	Maint. Of Meas. & Reg. Station Expenses-Indust.	265,054	MaintExp				265,054		
71	891	Maint. Of Meas. & Reg. Station Expenses-CityGate	156,052	MaintExp				156,052		
72	892	Maint. Of Services	336,040	MaintExp			336,040			
73	893	Maint. Of Meters & House Regulators	690,238	MaintExp			690,238			
74	894	Maint. Of Other Equipment	191,121	MaintExp	-	-	103,410	87,711		
75	N/A	Distribution Adjustments	192,214	DistExp	4,140	-	48,277	139,797		
76		Customer Accounts	2,595,999	DA		2,595,999				
77		Customer Service	205,342	DA		205,342				
78		Sales	142,695	DA		142,695				
79		Administrative And General	10,427,842	O&M	140,190	3,380,855	1,933,192	4,973,605		
80		CPP Labor	58,926	RNGExp						58,926
81		Depreciation & Amortization	12,227,050	Plant	$0	$0	$4,506,805	$7,720,245		
82		Depreciation & Amortization - RNG	52,456	RNGExp						52,456
83		Regulatory Debits	(9,367)	Plant	$0	$0	($3,452)	($5,914)		
84		Taxes Other Than Income	9,895,171	Plant	$0	$0	$3,647,291	$6,247,880		
85		State & Federal Income Taxes	(425,355)	Plant	$0	$0	($156,783)	($268,572)		
86		**Total Operating Expense**	$ 42,759,138		$ 554,084	$ 6,324,891	$ 11,768,669	$ 24,000,112	$ -	$ 111,382
87										
88										
89		**Functionalized Revenue Requirement**	$ 60,920,455		$ 554,084	$ 6,324,891	$ 18,442,252	$ 35,312,116	$ 175,730	$ 111,382

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

PLANT CARRYING COSTS

EXHIBIT 708

November 2025

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line No.	Description	Unit	Total	101 Residential Service	104 Commercial Service	105 Industrial Service	111 Large Volume Service	163 General Distribution Interruptible	170 Interruptible
				core	core	core	core	non-core	core
1	**Billing Determinants**								
2	Peak Day Forecast	Dth-Day	84,118	49,468	28,961	2,368	1,566	-	1,756
3	Customer Count	#	89,119	78,223	10,682	160	16	34	4
4	Throughput	Dth	15,126,409	5,555,029	3,405,492	322,090	274,542	5,308,998	260,259
5									
6	**Service Installation**								
7	Typical Size	in.		<1.25 Inches	<1.25 Inches	2 Inches			
8	Material			Plastic	Plastic	Plastic			
9	Average Cost	$		$ 2,535	$ 2,535	$ 6,112			
10	Total Investment	$	$ 228,953,524	$ 198,293,353	$ 27,078,261	$ 977,485	$372,545	$1,827,367	$404,514
11	Economic Carrying Charge Rate	%		17.06%	17.06%	17.06%	17.06%	17.06%	17.06%
12	Annual Carrying Charge Per Customer	$		$ 432.51	$ 432.51	$ 1,042.85			
13	Class Annual Carrying Charge	$	$ 39,063,155	$ 33,832,037	$ 4,619,987	$ 166,775	$ 63,562	$ 311,778	$ 69,017
14									
15	**Meters & Regulators**								
16	Average Cost	$		$ 411	$ 1,226	$ 5,566			
17	Total Investment	$	$ 48,760,875	$ 32,142,200	$ 13,092,977	$ 890,123	$ 669,830	$ 1,649,419	$ 316,325
18	Economic Carrying Charge Rate	%		18.29%	18.29%	18.29%	18.29%	18.29%	18.29%
19	Annual Carrying Charge Per Customer	$		$ 75.16	$ 224.21	$ 1,018.15			
20	Class Annual Carrying Charge	$	$ 8,919,561	$ 5,879,597	$ 2,395,027	$ 162,825	$ 122,528	$ 301,719	$ 57,864
21									
22	**Mains Investment**								
23	*Customer Mains Investment*								
24	Typical Size	in.		2	2	2			
25	Material			Plastic	Plastic	Steel			
26	Avg. Mains Extension Per Cust	ft		44.00	44.00	844.75			
27	Average Cost Per Ft	$/ft		$16.01	$16.01	$83.68			
28	Customer Mains Investment Per Customer	$		$ 704	$ 704	$ 70,691			
29	Customer Mains Investment By Class	$	$ 107,637,053	$ 55,092,073	$ 7,523,185	$ 11,305,161	$4,720,979	$24,981,053	$ 4,014,602
30									
31	*Long-Run System Replacement Investment*								
32	Mains System Replacement Cost	$	$ 1,029,200,387						
33	Less: Customer Mains Investment	$	$ (107,637,053)						
34	Long-Run System Replacement Investment	$	$ 921,563,334						
35									
36	*Capacity*	%	68%						
37	Investment Per Peak Day Capacity	$/Dth-Day	$ 7,452						
38	Investment By Class	$	$ 626,891,587	$ 368,658,103	$ 215,828,519	$ 17,647,441	$ 11,670,567	$ -	$ 13,086,956
39	Investment Per Customer	$		$ 4,713	$ 20,205	$ 110,350	$ 724,824	$ -	$ 3,271,739
40									
41	*Commodity*	%	32%						
42	System Replacement Investment Per Dth	$/Dth	$ 19.48						
43	Investment By Class	$	$ 294,671,747	$ 108,215,375	$ 66,341,081	$ 6,274,502	$ 5,348,239	$ 103,422,552	$ 5,069,998
44	Investment Per Customer	$		$ 1,383	$ 6,211	$ 39,235	$ 332,163	$ 3,041,840	$ 1,267,499
45									
46	Total Mains Investment By Class	$	$ 1,029,200,387	$ 531,965,551	$ 289,692,786	$ 35,227,104	$ 21,739,786	$ 128,403,605	$ 22,171,556
47	Economic Carrying Charge Rate			16.27%	16.27%	16.27%	16.27%	16.27%	16.27%
48	Class Annual Carrying Charge	$	$ 167,425,535	$ 86,537,683	$ 47,125,876	$ 5,730,582	$ 3,536,527	$ 20,888,102	$ 3,606,766
49									
50	**Total Carrying Costs**	**$**	**$ 215,408,251**	**$ 126,249,317**	**$ 54,140,890**	**$ 6,060,182**	**$ 3,722,618**	**$ 21,501,599**	**$ 3,733,646**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

OPERATIONS & MAINTENANCE EXPENSES

EXHIBIT 709

November 2025

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Operations and Maintenance Expenses

Line No.	Description	Total	101 Residential Service	104 Commercial Service	105 Industrial Service	111 Large Volume Service	163 General Distribution Interruptible	170 Interruptible
			core	core	core	core	non-core	core
1	**Billing Determinants**							
2	Peak Day Forecast	84,118	49,468	28,961	2,368	1,566	-	1,756
3	Customer Count	89,119	78,223	10,682	160	16	34	4
4	Throughput	15,126,409	5,555,029	3,405,492	322,090	274,542	5,308,998	260,259
5	Sales	9,817,410	5,555,029	3,405,492	322,090	274,542		260,259
6								
7	Peak & Average	100%	47.8%	28.5%	2.5%	1.8%	17.5%	1.9%
8								
9	Customer Count (Small Customers)	89,065	78,223	10,682	160			
10	Customer Count (Large Customers)	54				16	34	4
11								
12	Volumes (Core)		5,555,029	3,405,492	322,090	274,542		260,259
13	Volumes (Non-Core)						5,308,998	
14								
15	**Gas Planning**							
16	Core	$ 105,943	$ 61,375	$ 36,583	$ 3,177	$ 2,362		$ 2,447
17	Non-Core	$ 26,486					$ 26,486	
18	Total Core + Non-Core	$ 132,429	$ 61,375	$ 36,583	$ 3,177	$ 2,362	$ 26,486	$ 2,447
19	Cost Per Customer		$ 0.78	$ 3.42	$ 19.86	$ 146.70	$ 779.00	$ 611.65
20								
21	**Gas Supply**							
22	Core	$ 194,919	$ 110,292	$ 67,614	$ 6,395	$ 5,451		$ 5,167
23	Non-Core	$ -					$ -	
24	Total Core + Non-Core	$ 194,919	$ 110,292	$ 67,614	$ 6,395	$ 5,451	$ -	$ 5,167
25	Cost Per Cust		$ 1.41	$ 6.33	$ 39.99	$ 338.54	$ -	$ 1,291.82
26								
27	**Gas Control**							
28	Core	$ 111,241	$ 62,944	$ 38,587	$ 3,650	$ 3,111		$ 2,949
29	Non-Core	$ 47,675					$ 47,675	
30	Total Core + Non-Core	$ 158,915	$ 62,944	$ 38,587	$ 3,650	$ 3,111	$ 47,675	$ 2,949
31	Cost Per Cust		$ 0.80	$ 3.61	$ 22.82	$ 193.20	$ 1,402.19	$ 737.24
32								
33	**Total Gas Supply O&M**	**$ 486,264**	**$ 234,611**	**$ 142,785**	**$ 13,221**	**$ 10,924**	**$ 74,160**	**$ 10,563**

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Operations and Maintenance Expenses

Line No.	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution Interruptible non-core	170 Interruptible core
34								
35	**Meter Reading**							
36	Meter Reading Expense (Res, Small Comm.)	$ 501,146	$ 440,142	$ 60,104	$ 900	$ -	$ -	$ -
37	Meter Reading Expense (Industrial)	$ 334	$ -	$ -	$ -	$ 99	$ 210	$ 25
38	Meter Reading Expense	$ 501,480	$ 440,142	$ 60,104	$ 900	$ 99	$ 210	$ 25
39	Cost Per Customer		$ 5.63	$ 5.63	$ 5.63	$ 6.18	$ 6.18	$ 6.18
40								
41	**Customer Account Records Billing And Collection**							
42	Expense	$ 1,577,522	$ 1,385,241	$ 189,164	$ 2,832	$ 285	$ 602	$ 71
43	Cost Per Customer		$ 17.71	$ 17.71	$ 17.71	$ 17.70	$ 17.70	$ 17.70
44								
45	**Uncollectible**							
46	Commercial	$ 86,256		$ 86,256				
47	Industrial	$ 1,607			$ 1,607			
48	Residential	$ 281,055	$ 281,055					
49	Total Or	$ 368,918	$ 281,055	$ 86,256	$ 1,607	$ -	$ -	$ -
50	Cost Per Customer		$ 3.59	$ 8.07	$ 10.05	$ -	$ -	$ -
51								
52	**Total Customer O&M**	**$ 2,447,921**	**$ 2,106,439**	**$ 335,524**	**$ 5,339**	**$ 384**	**$ 812**	**$ 96**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 525

Cascade Natural Gas Corporation

ANNUAL CARRYING CHARGE CALCULATIONS

EXHIBIT 710

November 2025

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Economic Carrying Charge - Mains

Line No.	Description			
1	**Annual Carrying Charge Model**			
2				
3				
4	Asset Name:	Mains		
5				
6	Capitalized Cost	$100		
7	Book Life	70 Years		
8	Salvage Value	-53%		
9	MACRS Life	20 Years		
10				
11		Proportion	Rate	Weighted
12	Debt	50.00%	5.33%	2.67%
13	Preferred Equity	0.00%	0.00%	0.00%
14	Common Equity	50.00%	10.40%	5.20%
15	Weighted Avg. Cost of Capital	100.00%		7.87%
16	After Tax Cost of Capital			7.15%
17				
18	Fed Tax Rate	21.00%		
19	State Tax Rate	7.60%		
20	Total Income Tax Rate	27.00%		
21				
22	O&M Rate	0.67%		
23	A&G Rate	2.44%		
24	Revenue Tax Rate	3.00%		
25	Property Tax Rate	2.31%		
26	Property Insurance Rate	0.00%		
27	Property Tax Basis (1=Original Cost, 2= Depr. Balance)	1		
28				
29	Inflation Rate	2.48%		
30	Pro Tax Esc Rate	2.48%		
31	Return Basis (1=Beginning of Year, 2=Avg., 3= EOY)	2		
32				
33	**Levelized Annual Carrying Charge**			**16.27%**
34				
35				
36				
37	**Year**	**Total**	**NPV**	**Levelized Payment**
38				
39	Book Value			
40	Book Depreciation	$109.29	$29.62	$2.13
41	Accumulated Depreciation			
42				
43	Rate Base			
44				
45	MACRS (%)			
46	Tax Depreciation	$100.00	$53.83	$3.88
47	Deferred Tax			
48				
49	Interest Expense	$51.09	$23.42	$1.69
50	Return on Preferred Equity	$0.00	$0.00	$0.00
51	Return on Common Equity	$99.66	$45.68	$3.29
52				
53	O&M	$64.52	$12.73	$0.92
54	A&G Expense	$235.96	$46.55	$3.35
55	Property Tax	$223.90	$44.17	$3.18
56	Insurance	$0.00	$0.00	$0.00
57				
58	Taxable Income			
59	Income Tax Payable	$36.87	$16.90	$1.22
60				
61	Revenue Requirement Before Revenue Tax	$821.29	$219.06	$15.78
62	Revenue Tax	$25.38	$6.77	$0.49
63	Annual Revenue Requirement	$846.66	$225.83	$16.27

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Sch 5c, Economic Carrying Charge - Meters

Line No.	Description			
1	**Annual Carrying Charge Model**			
2				
3				
4	Asset Name:	Meters		
5				
6	Capitalized Cost	$100		
7	Book Life	40	Years	
8	Salvage Value	-5%		
9	MACRS Life	20	Years	
10				
11		Proportion	Rate	Weighted
12	Debt	50.00%	5.33%	2.67%
13	Preferred Equity	0.00%	0.00%	0.00%
14	Common Equity	50.00%	10.40%	5.20%
15	Weighted Avg. Cost of Capital	100.00%		7.87%
16	After Tax Cost of Capital			7.15%
17				
18	Fed Tax Rate	21.00%		
19	State Tax Rate	7.60%		
20	Total Income Tax Rate	27.00%		
21				
22	O&M Rate	1.83%		
23	A&G Rate	2.44%		
24	Revenue Tax Rate	3.00%		
25	Property Tax Rate	2.31%		
26	Property Insurance Rate	0.00%		
27	Property Tax Basis (1=Original Cost, 2= Depr. Balance)	1		
28				
29	Inflation Rate	2.48%		
30	Pro Tax Esc Rate	2.48%		
31	Return Basis (1=Beginning of Year, 2=Avg., 3= EOY)	2		
32				
33	**Levelized Annual Carrying Charge**			**18.29%**
34				
35				
36				
37	Year	Total	NPV	Levelized Payment
38				
39	Book Value			
40	Book Depreciation	$105.00	$34.41	$2.63
41	Accumulated Depreciation			
42				
43	Rate Base			
44				
45	MACRS (%)			
46	Tax Depreciation	$100.00	$53.83	$4.11
47	Deferred Tax			
48				
49	Interest Expense	$43.89	$22.07	$1.68
50	Return on Preferred Equity	$0.00	$0.00	$0.00
51	Return on Common Equity	$85.60	$43.04	$3.28
52				
53	O&M	$122.70	$32.59	$2.49
54	A&G Expense	$163.38	$43.39	$3.31
55	Property Tax	$155.03	$41.18	$3.14
56	Insurance	$0.00	$0.00	$0.00
57				
58	Taxable Income			
59	Income Tax Payable	$31.67	$15.92	$1.21
60				
61	Revenue Requirement Before Revenue Tax	$707.26	$232.61	$17.74
62	Revenue Tax	$21.85	$7.19	$0.55
63	Annual Revenue Requirement	$729.12	$239.79	$18.29

Cascade Natural Gas Corporation
Long Run Incremental Cost (LRIC) Study
Sch 5b, Economic Carrying Charge - Services

Line No.	Description			
1	**Annual Carrying Charge Model**			
2				
3				
4	Asset Name:	Service		
5				
6	Capitalized Cost	$100		
7	Book Life	48	Years	
8	Salvage Value	-71%		
9	MACRS Life	20	Years	
10				
11		Proportion	Rate	Weighted
12	Debt	50.00%	5.33%	2.67%
13	Preferred Equity	0.00%	0.00%	0.00%
14	Common Equity	50.00%	10.40%	5.20%
15	Weighted Avg. Cost of Capital	100.00%		7.87%
16	After Tax Cost of Capital			7.15%
17				
18	Fed Tax Rate	21.00%		
19	State Tax Rate	7.60%		
20	Total Income Tax Rate	27.00%		
21				
22	O&M Rate	0.86%		
23	A&G Rate	2.44%		
24	Revenue Tax Rate	3.00%		
25	Property Tax Rate	2.31%		
26	Property Insurance Rate	0.00%		
27	Property Tax Basis (1=Original Cost, 2= Depr. Balance	1		
28				
29	Inflation Rate	2.48%		
30	Pro Tax Esc Rate	2.48%		
31	Return Basis (1=Beginning of Year, 2=Avg., 3= EOY)	2		
32				
33	**Levelized Annual Carrying Charge**			**17.06%**
34				
35				
36				
37	**Year**	**Total**	**NPV**	**Levelized Payment**
38				
39	Book Value			
40	Book Depreciation	$171.00	$48.04	$3.56
41	Accumulated Depreciation			
42				
43	Rate Base			
44				
45	MACRS (%)			
46	Tax Depreciation	$100.00	$53.83	$3.99
47	Deferred Tax			
48				
49	Interest Expense	$19.81	$18.82	$1.40
50	Return on Preferred Equity	$0.00	$0.00	$0.00
51	Return on Common Equity	$38.65	$36.71	$2.72
52				
53	O&M	$77.97	$16.31	$1.21
54	A&G Expense	$219.99	$46.03	$3.41
55	Property Tax	$208.75	$43.68	$3.24
56	Insurance	$0.00	$0.00	$0.00
57				
58	Taxable Income			
59	Income Tax Payable	$14.30	$13.58	$1.01
60				
61	Revenue Requirement Before Revenue Tax	$750.46	$223.17	$16.55
62	Revenue Tax	$23.19	$6.90	$0.51
63	Annual Revenue Requirement	$773.65	$230.06	$17.06