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August 22, 2024

BY E-FILING

Mr. Adam Teitzman, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20240099-EI - Petition for rate increase by Florida Public Utilities Company

Dear Mr. Teitzman:

Attached, for electronic filing, on behalf of Florida Public Utilities Company, please find the Testimony and Exhibits of Nick Crowley.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

(Document 6 of 18)

Sincerely,

A handwritten signature in black ink, appearing to read 'Beth Keating', written over a horizontal line.

Beth Keating
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1 BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

2 Docket No. 20240099-EI: Petition for rate increase by Florida Public Utilities Company-
3 Electric Division

4
5 PREFILED DIRECT TESTIMONY OF
6 Nicholas A. Crowley

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11 Date of Filing: August 22, 2024

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15 Focus of Testimony: Cost of Capital Study

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18 Exhibits: Exhibit NAC-1 Resume
19 Exhibits NAC-2-36 Cost of Capital Results

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1 Pre-filed Direct Testimony
2 Of
3 Nicholas A. Crowley

4 **1. Introduction**

5 **Q. Please state your name, affiliation, and business address.**

6 A. My name is Nicholas Allen Crowley. I am a Vice President at Christensen Associates
7 Energy Consulting, LLC (“CA Energy Consulting”). My business address is 800
8 University Bay Drive, Madison, Wisconsin, 53705.

9 **Q. On whose behalf are you submitting this testimony?**

10 A. I am submitting this pre-filed direct testimony before the Florida Public Service
11 Commission on behalf of Florida Public Utilities Company.

12 **Q. Please describe your education and experience.**

13 A. I have a Bachelor of Science in economics and a Master of Science in economics from
14 the University of Wisconsin-Madison. I began working at Christensen Associates
15 Energy Consulting in 2016. Prior to joining this consulting group, I was an Economist
16 in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission
17 (“FERC”), where I assisted with energy industry benchmarking, the incentive regulation
18 of oil pipelines,¹ and the review and evaluation of natural gas pipeline rate cases. In
19 these regulatory roles, I worked extensively with utility energy data and financial
accounting data used for the development of cost of capital studies, among other

¹ Five-Year Review of the Oil Pipeline Index. Issued: December 17, 2015. 153 FERC ¶ 61,312.

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1 analytics related to utility rate filings. My curriculum vitae is contained within
2 Appendix I as Exhibit NAC-1.

3 **Q. Have you previously testified before the Florida Public Service Commission or**
4 **other state regulatory commission?**

5 A. I have not testified before the Florida Public Service Commission (“Florida PSC”) prior
6 to this engagement. However, I have testified on behalf of utilities in both the United
7 States and Canada. Most recently, I testified regarding cost of capital on behalf of
8 Alpena Power Company in Michigan.² I have also testified in Massachusetts and
9 Alberta, Canada.^{3,4,5} I have authored reports on electric and gas utility cost of capital that
10 were filed in the Caribbean and in the state of Wisconsin.⁶ In addition to cost of capital
11 testimony, my work includes incentive regulation framework evaluations, cost-of-
12 service analysis, marginal costs studies, and rate design. My reports have been filed
13 before regulatory authorities in the United States and Canada.⁷

² Direct Testimony of Nicholas A. Crowley, Case No. U-21488, December 11, 2023.

³ Direct Testimony of Nicholas A. Crowley, D.P.U. 23-80 and D.P.U. 23-81, August 17, 2023.

⁴ Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

⁵ Determination of the Third-Generation X Factor for the AUC Price Cap Plan, Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, January 20, 2023.

⁶ For Grand Bahama Power Company, in 2018 and again in 2021. Also, for St. Croix Gas Company, located in western Wisconsin, in 2019.

⁷ For example, *Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029*, Prepared for Newfoundland and Labrador Hydro, November 15, 2018.

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1 **Q. How will you refer to the Company?**

2 A. When referring to the Florida Public Utilities Company Electric Division, I will refer to
3 it as “FPUC” or “the Company.” When referring to Chesapeake Utilities Corporation,
4 the parent company, I will refer to it as “CUC” or the “Corporation.”

5 **Q. Please provide an outline for this testimony.**

6 A. Following this introduction, my testimony is organized in sections, as follows:

2. Purpose and Overview of Testimony
3. Fundamentals of Cost of Capital
4. Monetary Policy, Interest Rates, and Macroeconomic Performance
5. Cost of Debt Analysis
6. Cost of Equity Estimation Methods
7. Cost of Equity Results
8. Capital Structure Analysis
9. The Weighted Average Cost of Capital
10. Summary and Conclusions

7 **2. Purpose and Overview of Testimony**

8 **Q. What is the purpose of your pre-filed direct testimony?**

9 A. The purpose of my direct testimony is to present evidence and provide a
10 recommendation regarding the cost of capital faced by Florida Public Utilities Company
11 (“FPUC,” or “the Company”). The cost of capital study described in this testimony
12 consists of an assessment of the Company’s projected capital structure and carrying cost
13 on outstanding long- and short-term debt, as well as my recommendations with respect
14 to the required return on equity. I discuss the Company’s recent financial history and
15 financial projections through test year 2025 including, in particular, the weighted
16 average cost rate of long-term debt which, reflects Chesapeake Utilities Corporation’s

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1 recent acquisition of Florida City Gas and ongoing need for incremental debt issues in
2 order to underwrite FPUC's rate base.

3 **Q. Have you prepared exhibits which support your testimony?**

4 A. Yes. I am sponsoring Exhibits NAC-1 through NAC-36, which are appended to this
5 testimony and can be found in Appendix II.

6 **Q. Please describe the Florida Public Utility Company's operations.**

7 A. FPUC, a wholly-owned subsidiary of Chesapeake, operates 3,154 miles of natural gas
8 distribution mains across 25 counties in Florida, serving approximately 96,000
9 customers. Additionally, FPUC owns and operates electric utility assets in five counties
10 in northeast and northwest Florida, distributing electricity to approximately 33,000
11 customers.

12 **Q. Briefly, what are the analyses you have conducted and what factors have you**
13 **considered that support your recommended ROE for FPUC in this proceeding?**

14 A. This testimony reports the results of an evaluation of FPUC's cost of debt, as well as a
15 recommendation for the company's allowed rate of return on equity (or "recommended
16 ROE"). The cost of debt analysis consists of a review of FPUC's short-term and long-
17 term debt issuances and cost rates. The recommended ROE is obtained by applying cost
18 of capital methods to Moderate-Sized Electric Utilities and Natural Gas Distribution
19 Utilities. These results were compared with small Non-Utility Companies with moderate
20 risk profiles. The sample entities provide a broad base of equity market experience of
21 utilities and comparable low-risk non-utilities operating on the North American
22 continent. This overall cost of equity estimate is obtained by applying four cost of equity

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1 methods including capital asset pricing model (“CAPM”), discounted cash flow
2 (“DCF”), risk premia, and an assessment of realized market returns.

3 **Q. Please summarize your recommendation with respect to the overall rate of return**
4 **for the Company.**

5 A. I recommend that the Florida Public Service Commission authorize the Company the
6 opportunity to earn a rate of return on equity with a mid-point of 11.30 percent. The
7 Company’s projected 13-month average capital structure for 2025 consists of 37.91
8 percent long-term debt at an attenuated embedded debt cost rate of 4.51 percent.
9 Chesapeake’s actual embedded cost of long-term debt is 5.21 percent, but the Company
10 has requested recovery of a reduced cost rate to lessen the requested overall rate of
11 return. The Company’s capital structure also consists of 4.83 percent short term debt at a
12 cost rate of 5.81 percent, and 42.82 percent common equity at my recommended ROE of
13 11.30 percent. The regulatory capital structure also contains customer deposits at a cost
14 rate of 2.2 percent, as well as deferred taxes and regulatory tax liabilities at zero cost.
15 The weighted average cost of capital (“WACC”) using these values is 6.89 percent. A
16 summary table is shown below.

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Table 1: Weighted Average Cost of Capital Results for FPUC (2025)

<u>EXHIBIT NAC-1</u>				
FLORIDA PUBLIC UTILITIES COMPANY				
OVERALL RATE OF RETURN REQUIREMENTS				
<u>WEIGHTED AVERAGE COST OF CAPITAL: REGULATORY CAPITAL STRUCTURE</u>				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long-Term Debt	\$56,888,413	37.91%	4.51%	1.71%
Short-Term Debt	\$7,255,028	4.83%	5.81%	0.28%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$64,253,557	42.82%	11.30%	4.84%
Customer Deposits	\$4,001,097	2.67%	2.20%	0.06%
Deferred Taxes	\$13,206,708	8.80%	0.00%	0.00%
Regulatory Tax Liability	\$4,448,275	2.96%	0.00%	0.00%
ITC at WACC	\$0	0.00%	7.98%	0.00%
Total	\$150,053,078	100.00%		6.89%
<u>WEIGHTED AVERAGE COST OF CAPITAL: CONVENTIONAL CAPITAL STRUCTURE</u>				
STATED ON A CONSOLIDATED BASIS				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long Term Debt	\$1,331,883,955	44.31%	4.51%	2.00%
Short-Term Debt	\$169,856,296	5.65%	5.81%	0.33%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$1,504,318,384	50.04%	11.30%	5.65%
Total	\$3,006,058,635	100.00%		7.98%

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1 **Q. Please provide a summary of the results of your cost of equity analysis.**

2 A. Table 2, below, provides a summary of the results of the cost of equity analysis.

3 **Table 2: Summary of Recommended Return on Equity (2025)**

COST OF EQUITY ESTIMATES, U.S. EQUITY MARKET-LISTED ENTITIES			
METHODOLOGY	Estimates		
	Low	High	Average
Discounted Cash Flow			
Mid-Sized Electric Utilities	9.37%	9.77%	9.57%
Gas Distribution Utilities	9.55%	12.08%	10.81%
Capital Asset Pricing Model			
Mid-Sized Electric Utilities	10.39%	11.61%	11.18%
Gas Distribution Utilities	10.14%	11.31%	10.72%
Low Risk Non-Utility Companies	10.10%	11.63%	11.29%
Risk Premia Model			
Mid-Sized Electric Utilities			10.52%
Gas Distribution Utilities			9.90%
Low Risk Non-Utility Companies			11.39%
Realized Market Returns, Rolling 10-Yrs			
<u>For 2013-2023</u>			
Mid-Sized Electric Utilities			11.52%
Gas Distribution Utilities			13.21%
Low Risk Non-Utility Companies			9.89%
Recommended Return on Equity	10.43%	12.21%	11.30%

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1 **3. Fundamentals of Cost of Capital**

2 **3.1 Definitions**

3 **Q. Please define what is meant by “cost of capital.”**

4 A. The cost of capital is the underlying rate used by investors to discount and value the
5 expected benefit flows obtained from holdings of financial assets and is also referred to
6 as the discount rate. The cost of capital is the compensation required by investors for
7 postponing consumption, for expected inflation, and for exposure to capital risks of
8 various dimensions, where such risks are, on the one hand, general to macroeconomies
9 and financial markets but also specific to the underlying investment vehicles used to
10 underwrite capital.

11 **Q. What are the elements of a firm’s capital structure?**

12 A. A firm’s capitalization consists of a mix of debt and equity. Corporate debt can take the
13 form of lines of credit and notes with banks and commercial lenders, mortgages, and
14 debenture bonds. Equity (or, common equity) of private entities, such as electric utilities
15 like FPUC, refers to the net accumulated value of contributed capital by equity investors.
16 At a general level, equity is in the form of common and preferred stock, and includes the
17 accrual of retained earnings, where investors, through the purchase of stock, assumes a
18 share in the ownership of a corporate entity. In some cases, debt instruments can
19 participate in equity returns and may also have rights of conversion to common stock.

20 **Q. What is a firm’s weighted average cost of capital (“WACC”)?**

21 A. The overall cost of capital, often referred to as the WACC and expressed in percentage
22 terms, incorporates the pool of financing vehicles used by the utility to underwrite and

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1 fund the capital that it employs in the provision of services to the public. The WACC is
2 the composite weighted cost of the financing vehicles including short-term debt, long-
3 term debt such as mortgage bonds, preferred stock, and common stock. These financing
4 vehicles constitute the financial contracts between lender and equity investors, and the
5 firm including government entities and private companies.

6 **Q. What does the term “long-term debt” mean in the context of utility capital?**

7 A. Long-term debt includes mortgage bonds, debentures, and long-term notes. The interest
8 on the principal amount of a bond, or the coupon rate on the share of preferred stock,
9 defines the level of compensation. Often, the interest rate is a predefined annual rate that
10 remains fixed over the term of the debt instrument. However, long-term debt instruments
11 may incorporate other provisions that provide for more complete contracting by
12 managing uncertainty through risk sharing between the debt holders (lenders) and issuers
13 (borrowers). These provisions can include adjustments to the rate of interest to reflect
14 contemporary market conditions and rates of inflation, call provisions, participation in
15 the earnings of the firm, conversion rights, and voting rights in the management of the
16 firm.

17 **Q. What is meant by “short-term debt”?**

18 A. Short-term debt includes credit lines or promissory notes with commercial banks.
19 Commercial terms may clarify that interest is to be paid monthly on the outstanding
20 daily balance in the case of lines of credit, or quarterly in the case of a promissory note.
21 The rate of interest applied to the outstanding balance can be tied to the interest rate on
22 obligations of some widely known financial market vehicle—say, the Secured Overnight

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1 Funding Rate (“SOFR”), or the Federal Funds rate, or the prime rate of commercial
2 banks—which also varies daily or monthly.

3 **Q. What is common equity, and how does it differ from debt instruments?**

4 A. Common stock property rights are somewhat different from other financial obligations
5 because, as owners of the firm, the returns to shareholders are residual, following the
6 compensation to other resources employed by the firm including debt obligations and
7 preferred stock. Common equity is essentially compensated last, and bears the burden of
8 much of the business, regulatory, and financial risks of investor-held entities. For this
9 reason, common equity is typically more costly than other forms of financial
10 instruments.

11 **Q. How are debt and equity securities exchanged between investors?**

12 A. As with many other markets, capital markets have primary and secondary dimensions.
13 Primary markets are the institutions and processes that facilitate the initial sale of the
14 financial obligations of the firm to investors, whereas secondary markets are structured
15 market processes that provide the means by which investors can purchase and sell
16 existing rights including shares of stock and debt obligations, as well as an array of
17 financial options to hedge, and to speculate on, financial risks. In general, equity markets
18 are more liquid than fixed income markets, meaning that sales and purchases of equities
19 can be made more quickly than specific bond securities.

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1 **Q. What determines a firm's cost of capital?**

2 A. The cost of capital is determined by several factors including the demand for capital, the
3 supply of savings across macroeconomies, expectations of inflation by capital market
4 participants, and, for specific investments, perceptions of risks harbored by investors.
5 The demand for capital is determined by expectations of future levels of economic
6 activity, while expected inflation is driven largely by monetary policy over the relevant
7 timeframe. Perceptions of risk, in turn, cover many dimensions of uncertainty including
8 future performance of individual investments and macroeconomies, and policy of
9 governing authorities regarding fiscal expenditures. To investors (savers) who hold
10 financial assets, expected benefits are in the form of future cash flows including interest
11 payments, dividend payments, market appreciation, and return of principal. When
12 investors supply funds to entities such as utilities and public entities (e.g., government
13 bonds), not only are they postponing consumption by foregoing value otherwise
14 obtained from alternative expenditures, they are also exposing funds to the potential
15 devaluation from ongoing inflation as well as to various uncertainties and risk attending
16 future cash flows. Investors are willing to incur these risk factors only if they are
17 adequately compensated. In brief, the cost of capital—the discount rate stated in nominal
18 terms—increases with rising demand for capital, with expectations of higher rates of
19 inflation, and with heightened perceptions of risk. As a practical matter, risk is arguably
20 the key contributing factor for the estimation of the cost of capital.

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1 **Q. What risks drive a firm's cost of capital and how do these risks interact with the**
2 **required return on investment?**

3 A. In addition to macroeconomic risks that affect all firms in the market, including a
4 nation's institutional stability, public policy, and climate issues, a firm's risk profile also
5 consists of idiosyncratic factors associated with specific capital resources, such as sector
6 risks, supply chain issues, management capabilities, and technological change.
7 Expectations of future financial conditions of the specific company also constitute
8 idiosyncratic risks. In debt markets, investors will re-price downward the bonds of a
9 private company should the current financial condition or perceived risk level of the
10 company suddenly decline. The decrease in the company's current condition, reflected
11 as reduced interest coverage, then causes the expectation of the future condition of the
12 company also to decline.⁸ Similarly, expectations of deteriorating earnings growth
13 diminish investor demand for the firm's common equity shares at a given price. The
14 decline in prices reflects a requirement by investors for a higher rate of return.

15 **Q. What are the institutions that participate in capital markets?**

16 A. Market participants, including lenders and holders of common and preferred stock,
17 supply capital as investors, while borrowers, including public and private entities and
18 common stock-issuing companies, constitute the demand side of capital markets.
19 Commercial banks, credit unions, finance companies, capital exchanges, private equity
20 funds, and investment banks serve as intermediaries that provide the institutional means

8 Bond prices and discount rates, in the form of the interest rates or bond yields (and yield to maturity), move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

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1 that facilitate the interaction and linkage of the supply and demand sides of capital
2 markets, focused on financing. These functions essentially include lending, borrowing,
3 and the issuance of equity vehicles. Banks and credit unions borrow (and store) financial
4 assets that in turn are invested in the form of debt and, to a lesser extent, equity.

5 **Q. Why must the cost of capital be estimated rather than observed directly?**

6 A. While the market prices of other inputs including labor, materials, and energy can be
7 easily verified, the cost of capital—essentially, the price of capital—is not easily
8 discerned, thus requiring estimation through the cautious application of analytical
9 methods. The cost of capital reflects expectations of future risks and returns, which
10 consistently change and cannot be directly observed. However, the cost of capital is
11 generally positive even in the absence of inflation and risks, as savers require
12 compensation for foregoing the right to use the funds saved for current consumption of
13 goods and services. This is a reflection of the time value of money.

14 ***3.2 Legal and Institutional Foundations for Return on Equity***

15 **Q. What are the legal and institutional foundations for a utility's allowed return on**
16 **equity?**

17 A. Statutory and legal guidelines for the regulation of a utility's *fair rate of return* in North
18 America are delineated in key decisions by authorities in Canada and the United States.
19 The statutory principles of rate of return for public utilities rest substantially with two
20 decisions of the Supreme Court of the United States. In the *Bluefield Water Works and*
21 *Improvement Co. v. Public Service Commission of West Virginia* case (262 U.S. 679,
22 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

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1 “...A public utility is entitled to such rates as will permit it to earn a return on
2 the value of the property which it employs for the convenience of the public
3 equal to that generally being made at the same time and in the same general
4 part of the country on investments in other business undertakings which are
5 attended by corresponding risks and uncertainties; but it has no constitutional
6 right to profits such as are realized or anticipated in highly profitable
7 enterprises or speculative ventures. The return should be reasonably
8 sufficient to assure confidence in the financial soundness of the utility and
9 should be adequate, under efficient and economical management, to maintain
10 and support its credit and enable it to raise the money necessary for the
11 proper discharge of its public duties. A rate of return may be reasonable at
12 one time and become too high or too low by changes affecting opportunities
13 for investment, the money market and business conditions generally.”

14 For capital committed by public utilities, a second landmark decision of the U.S.
15 Supreme Court echoed the “Bluefield” decision and expanded upon the fair return
16 standard for capital committed to public utilities. This second decision is the *Federal*
17 *Power Commission v. Hope Natural Gas Company* case (320 U.S. 391, 1944); a relevant
18 passage of the decision, referred to as *Hope*, is as follows:

19 From the investor or company point of view it is important that there
20 be enough revenue not only for operating expenses but also for the
21 capital costs of the business. These include service on the debt and
22 dividends on the stock[...] By that standard the return to the equity
23 owner should be commensurate with return on investments in other
24 enterprises having corresponding risks. That return, moreover, should
25 be sufficient to assure confidence in the financial integrity of the
26 enterprise, so as to maintain its credit and attract capital.

27
28 These longstanding decisions provide a more-or-less universally accepted framework for
29 determining the fair rate of return on capital committed by investors to public service.⁹ In

⁹ In the Permian Basin Area Rate Cases (390 U.S., 747, 1968), the U.S. Supreme Court stressed that:

“the court must determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. The court’s responsibility is not to supplant the Commission’s balance of these interests with one more nearly to its liking, but instead to assure itself that the Commission has given reasoned consideration

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1 these decisions, the U.S. Supreme Court codified, in clear and well understood
2 terminology, benchmarks for setting fair and equitable prices for utility services,
3 including electricity, while also providing a fair rate of return on the capital provided by
4 investors. Though reaching back many years, these decisions are relevant and thus often
5 cited within utility regulation. To this day, they serve as the cornerstone for the
6 determination of rate of return and remain relevant for setting cost-based utility rates.
7 The immediate challenge for regulators, regulated utilities, and interested parties to rate
8 setting proceedings is to operationalize these principles in contemporary regulatory
9 processes.

10 *3.3 Financial Market Efficiency, Capital Valuation, and Utility Cost of Capital*

11 **Q. How do market expectations affect a firm's cost of capital?**

12 A. Expected market returns inform investors' required rate of return. Under the assumption
13 of efficient markets, competition inherent to U.S. and selected worldwide financial
14 markets implies that the prices of common shares (share prices) and bonds reside at
15 levels that reflect the opportunity cost of capital. As an example, assume that the
16 perceived risks attending the expected returns to common shareholders of Firm A are
17 equivalent to those of Firm B and other firms. If the share prices of Firm A imply an
18 expected market return of 10 percent, while the prices of Firm B and other firms of
19 comparable risks suggest (allow) market returns of 13 percent, the market price of Firm
20 A will fall to a level that provides a basis for market returns of just 13 percent,

to each of the pertinent factors.”

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1 prospectively. A price that allows for a 10 percent prospective market return is
2 insufficient in the presence of opportunities for a market return of 13 percent on
3 alternative investments of comparable risk. Essentially, the 13 percent market rate of
4 return on investment alternatives constitutes the opportunity cost of capital. In short,
5 equivalent and comparable risks translate directly into comparable market rates of
6 return, as expected. This is the cost of capital of common shareholders in the firm.

7 **Q. How is the cost of capital expressed in financial markets?**

8 A. Whereas the cost of skilled labor, materials and supplies, and inputs (including fuel)
9 employed in the provision of utility services are expressed in money terms, the cost of
10 capital is expressed as an interest rate, typically shown as an annual percentage of
11 investment. This means that the costs of the capital resources employed by FPUC,
12 including generation equipment, power delivery systems such as transformers and lines,
13 meters, trucks and vehicles, computer systems, software, office facilities and buildings,
14 inventory and stores, and land—essentially, the rate base of FPUC—are reflected as
15 annual carrying charges. The cost of capital for FPUC is referred to as the required rate
16 of return (percent) on the capital resources committed by investors to FPUC, where
17 capital is valued at either original cost or fair value.¹⁰

¹⁰ For the determination of setting retail utility prices in the U.S. and elsewhere, the regulatory convention is to value the capital of public utilities at original cost. Other measures of capital value including fair value and trended original cost have been applied, particularly during eras of high rates of inflation and under circumstances where original cost measures cause distortions in the relevant costs and prices of complementary or substitute inputs.

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1 ***3.4 Regulation, Demand for Capital, and Capital Attraction***

2 **Q. In general, why do utilities require resources from capital markets?**

3 A. The cost of capital concept may also be interpreted from the perspective of internal
4 investments and the demand for resources. Regulated utilities accommodate, by law, the
5 ongoing and steadily rising demand for services, which involves the expanding
6 employment of resources, capital in particular. Senior managers of firms, as agents for
7 the ownership or controlling interest of the entity such as shareholders or a local
8 municipality, are responsible for ensuring that the expected internal returns on
9 incremental capital committed by the firm are equivalent to the cost of capital to the
10 firm—i.e., investors' rate of return requirements. The adequacy of the internal returns on
11 incremental investment by electric utilities to fund capital at full opportunity costs,
12 however. This is highly dependent upon the soundness of the regulatory governance
13 structure to ensure that the utility has the opportunity to obtain sufficient revenues,
14 which in turn provide adequate returns on incremental investment in new facilities.

15 **Q. What are the consequences of a mismatch in a utility's cost of capital and its**
16 **allowed rate of return?**

17 A. Public utilities such as FPUC utilize and employ substantial levels of capital resource
18 inputs to provide utility services. In general, the flow of revenues less the costs of non-
19 capital inputs to the firm, such as operating expenses, provides a level of dollar returns to
20 capital, in the form of operating income. If the level of income matches expectations,
21 investors realize returns equivalent to the overall cost of capital. When the rate of return,
22 set by regulators, leads to inadequate returns to capital or to the expectation that returns

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1 to capital are likely to be insufficient, utility managers are understandably reluctant to
2 make investments in infrastructure. Indeed, when the expansion of capital resources
3 occurs under a regulatory requirement including the obligation to serve, the absence of
4 adequate returns may be interpreted to implicitly constitute the confiscation of the
5 capital. Under these regulatory conditions, the utility is forced to provide services that
6 involve new investment, even though adequate returns are not obtainable. The result can
7 be a failure of capital attraction by the utility, and the confiscation of capital of
8 investors—a direct result of the inherent efficiency of competitive capital markets.

9 **Q. Please explain further what is meant by a “confiscation of capital” of investors.**

10 A. If the utility’s allowed rate of return is below its cost of capital, equity share prices can
11 be significantly bid down, giving rise to a sharp decline in the market capitalization of
12 the firm. The result is a wealth transfer from shareholders, as investors, to retail
13 consumers. In short, the capital of investors can be confiscated as a consequence of
14 compromised regulatory outcomes. Further, the regulatory governance structure,
15 particularly where the utility has binding service requirements and constraints, causes a
16 breach of fairness criteria and leads to a failure of the utility to satisfy capital attraction
17 standards where capital can be raised at fair and equitable terms. Essentially, higher
18 costs of debt interest charges result from the reduced credit standing in view of the lower
19 levels of interest coverage.

20 **Q. How do capital costs differ for utilities, relative to other industries?**

21 A. A utility and its managers can find themselves, as a result of service requirements,
22 forced to invest in real physical assets that are uneconomic from the perspective of the

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1 firm and its constituent investors, should the return on ongoing investments fall short of
2 the cost of capital. Given that the cost of capital is the minimum rate of return that must
3 be earned on physical assets to justify their acquisition, the regulator must be mindful of
4 the allowed rate of return levels and implement regulatory procedures that provide the
5 utility with an acceptable opportunity to realize returns, on the margin, that satisfy the
6 cost of capital—i.e., a rate of return equivalent to that realized on investments of
7 comparable risks. In the context of a binding regulatory constraint, and other regulatory
8 requirements such as obligations to serve, it is sufficient, but also necessary for the
9 required rate of return on incremental investment to adequately satisfy the opportunity
10 cost of funds. For this reason, the regulator should set the allowed rate of return equal to
11 the cost of capital so that the utility may satisfy its capital needs and service customers at
12 fair prices.

13 **Q. Why is it important for the regulator to set the utility's cost of capital using**
14 **empirical measurements, rather than “rules of thumb”?**

15 A. Investments and capital expansion are undertaken by utilities without inappropriate and
16 unfair wealth transfers between consumers and shareholders if, and only if, the allowed
17 rate of return is set at levels which are equal to the cost of capital. Whereas setting
18 allowed returns below the cost of capital constitutes a wealth transfer from investors to
19 utility customers, if the allowed rate of return is *greater* than the cost of capital,
20 investors' opportunity costs are more than achieved. Any excess earnings over and
21 above those required to service debt capital accrue to equity holders, resulting in a rise in
22 share prices. In such a scenario, a wealth transfer occurs from electricity consumers to

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shareholders. Therefore, setting the allowed rate of return equal to the cost of capital is the only policy that ensures commitment of necessary investments to satisfy utility service requirements while also providing fair and equitable returns to investors.

4. Monetary Policy, Interest Rates, and Macroeconomic Performance

Q. How does the United States Federal Reserve Bank's monetary policy influence cost of capital in the market?

A. Monetary policy has major influence on the cost of capital through the cost rates for various categories of financial assets and in the form of risks associated with financial assets, as incurred by the holders of those assets. Monetary policy is carried out through several channels and, as exercised by the United States Federal Reserve System, has a marked impact on interest rates worldwide.

Q. Please provide a brief history of recent monetary policy.

A. Modern monetary history includes three broad policy changes including the abrupt U.S. abandonment of the gold standard in 1971, and the institution of money supply targeting beginning in late-1979. Abandonment of the gold standard facilitated floating exchange rates across major economies. Money supply targeting, exercised through open market operations, are responsible for significant reductions in price inflation across the western economies during the 1980s and, subsequently, in many emerging markets during the time between the late 1990s and approximately 2005. In addition, nations unconstrained by the limits of gold reserves had leeway to address the presence of substantially reduced liquidity across western economies brought on by the global financial crisis

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1 through the implementation of quantitative easing monetary policy between 2008 and
2 2015. This resulted in the vast expansion of money supply aggregates.

3 **Q. How have yields on short-term U.S. Treasury debt changed over time?**

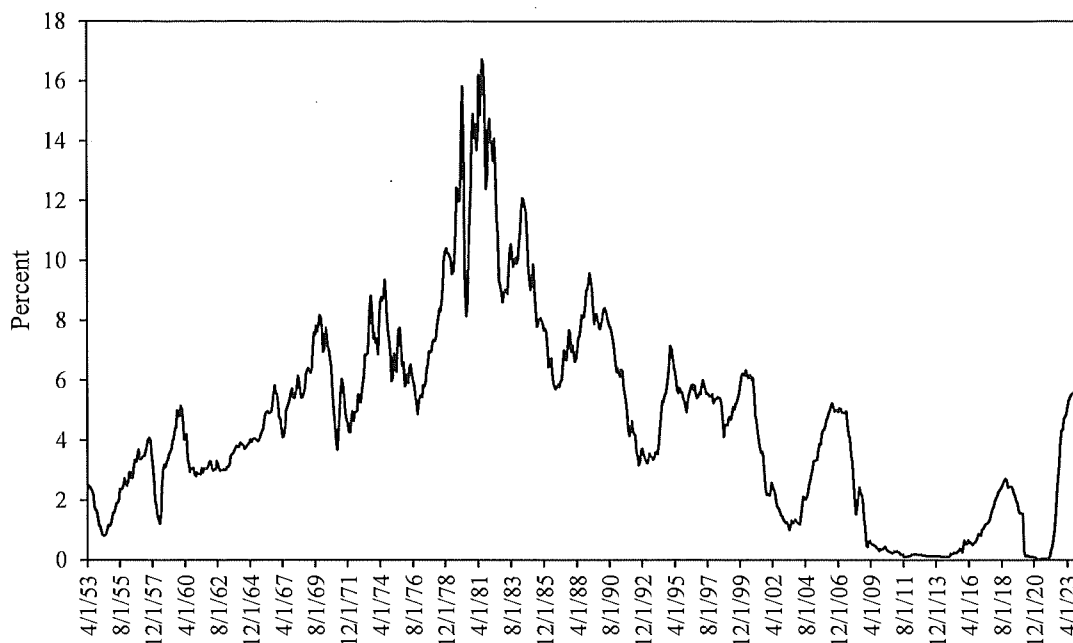
4 A. Shown in Figure 1 are yields on short-term U.S. Treasury debt since 1950. As displayed
5 in the figure, short-term interest rates—proxied by yields on 90-day U.S. Treasury
6 Bills¹¹—reached slightly above 16 percent during the second half of 1981. As a
7 consequence of the exceptionally high financing costs, aggregate demand and overall
8 price inflation was substantially reduced, as expectations of future price inflation were
9 anchored downward by the early 1990s. Often referred to as the great moderation, the
10 period of money supply targeting and discretionary control of interest rates prevailed as
11 the central monetary policy through late-2007, manifested in rising interest rates as real
12 economic activity accelerated, and decreasing interest rates as economic activity slowed.

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¹¹ Interest rates on short-term debt are highly correlated such that yields on short U.S. T-Bills serves as a proxy for other short-term investments including (until recently), LIBOR and short-duration commercial paper.

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Figure 1: Yields on Treasury Bills of 90-Day Duration (1953-2023)



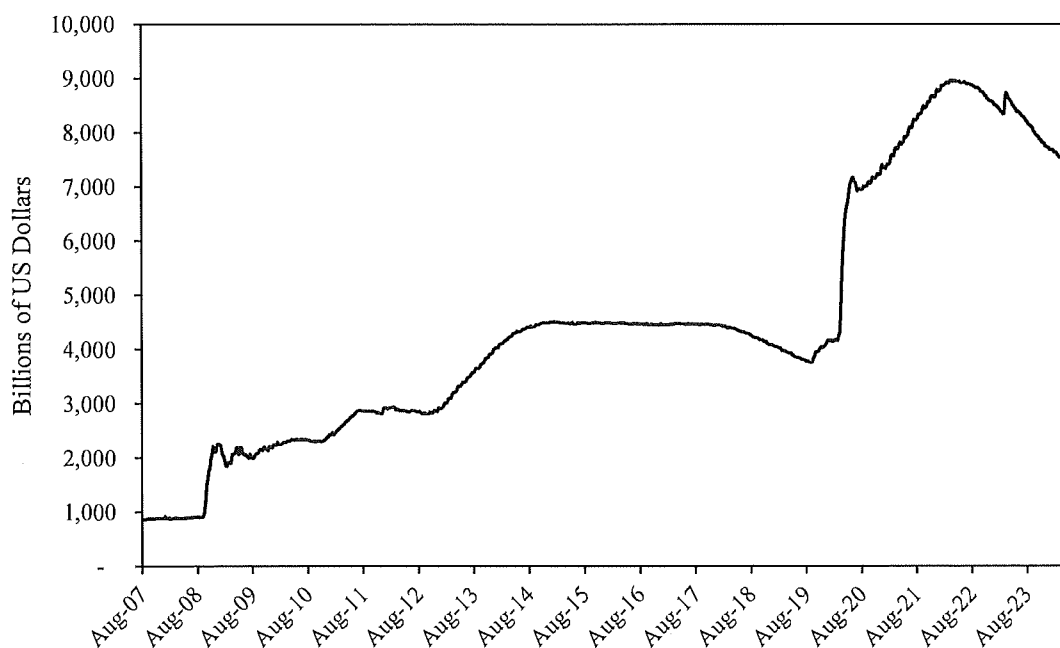
The deep recession of 2008-2009 ushered in abrupt policy changes, including a sudden sharp drop in short-term interest rates to near zero in early-2008. Evidence suggests that, all else equal, low real interest rates can contribute significantly to increased economic activity, at least under normal conditions. Under recessions and other conditions of economic and social stresses, economic agents hold comparatively high balances of cash and cash equivalents as precautionary savings,¹² essentially acting as insurance to manage uncertainty and risk. To the extent that comparatively low interest rates precipitate higher rates of aggregate demand including household consumption (services, non-durable and durable goods) and business investment, the level of overall economic activity can rise, without major increases in overall price inflation.

¹² Reference James Tobin, *Liquidity Preference and Behavior Toward Risk*, Cowles Foundation and Review of Economics and Statistics, 1958.

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The Federal Reserve’s policy to reduce interest rates in 2008 was supplemented with quantitative easing, a vast expansion of money supply in the form of cash equivalents. Quantitative easing was exercised through open market operations whereby the U.S. Federal Reserve purchased sizable quantities of financial assets, concentrated in mid-term U.S. Treasury securities. Such expansion of quantity aggregates, first implemented on a large scale by the U.S. Federal Reserve beginning in 2011, was instrumental in returning western economies to near full employment, following the depths of the world recession, 2007-2009/10. The Federal Reserve’s balance sheet holdings from 2007 through 2023 are provided in Figure 2.

Figure 2: Balance Sheet Assets of the U.S. Federal Reserve (2007-2023)



Viewed with respect to the long-term post war history, 2009 ushered in an era of anomalous conditions: attenuated economic growth with a sizable gap between real potential economic output, coupled with fairly high levels of household stress and

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1 uncertainty. Under these conditions, economic agents are willing to hold large
2 precautionary balances (cash and equivalents). U.S. personal savings rates—percent of
3 household disposable income—increased approximately 2-4 percent during the late-
4 1990s to 2007, increased again to 7 percent between 2010 and 2019, spiked during the
5 pandemic, and then fell following distribution of the Covid-19 vaccines. Under these
6 conditions, sizable increases in monetary aggregates are absorbed as additional
7 precautionary savings balances. Not until expenditures by households and private
8 business sectors return to normal does economic activity return to near the level of
9 potential output. Where precautionary balances are unusually high, the return of
10 confidence in macroeconomic performance can translate into a much higher level of
11 aggregate demand. In turn, price inflation can rise significantly, particularly in the
12 absence of a corresponding increase in aggregate supply.

13 In the first year of the Covid-19 pandemic, the federal government deployed widespread
14 resources in the form of the Paycheck Protection Program and direct payments to U.S.
15 citizens. At the same time, the Federal Reserve lowered interest rates to zero and began a
16 new round of quantitative easing in an effort to avoid a financial panic. Shortly
17 thereafter, global conflict arose in the form of Russia's invasion of Ukraine, which
18 shocked grain and energy markets not just in Europe, but around the world. These
19 developments contributed to the inflation of 2022 and 2023, which peaked in June 2022
20 at an annual rate of 9.1 percent, as measured by the BLS Consumer Price Index. While
21 certain inflation drivers declined in the first half of 2024, the global political landscape
22 remains highly uncertain, with the ongoing wars in Ukraine and in the Middle East.

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1 Beginning in the late-1980s and early-1990s, Federal Reserve monetary policy was
2 centered on setting interest rates at levels that translated into ongoing price inflation of
3 2.0 percent. Essentially, the Federal Reserve would set short-term interest rates, executed
4 through open market operations, at levels which maintained overall price inflation near
5 this 2.0 percent level. However, recent experience has somewhat altered the forward-
6 looking perspective of inflation, leading to higher interest rates and great concern with
7 regard to international energy markets. As stated by Federal Reserve Chairman Powell
8 during the Federal Reserve's annual 2023 conference:¹³

9 It is the Fed's job to bring inflation down to our 2 percent goal, and we
10 will do so. We have tightened policy significantly over the past year.
11 Although inflation has moved down from its peak—a welcome
12 development—it remains too high [...] Since last year's symposium,
13 the two-year real yield is up about 250 basis points, and longer-term
14 real yields are higher as well—by nearly 150 basis points. Beyond
15 changes in interest rates, bank lending standards have tightened, and
16 loan growth has slowed sharply [...] At upcoming meetings, we will
17 assess our progress based on the totality of the data and the evolving
18 outlook and risks. Based on this assessment, we will proceed carefully
19 as we decide whether to tighten further or, instead, to hold the policy
20 rate constant and await further data.

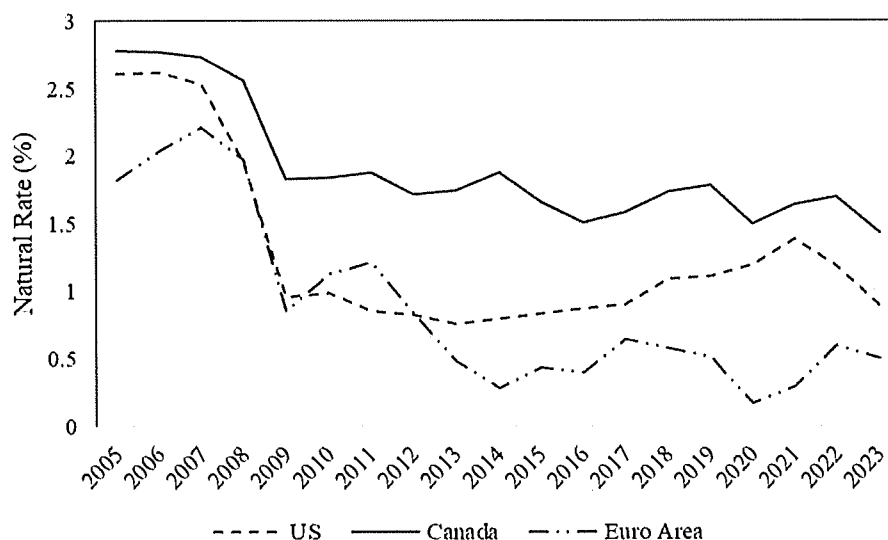
21 Chairman Powell's signal that inflation is the predominant concern of the Federal
22 Reserve indicates that the federal funds rate is unlikely to be reduced substantially in the
23 near term.
24 To combat the rise of inflation, Fed Chair Jerome Powell and the Federal Reserve began
25 hiking interest rates in March 2022. Over the following 16 months, the Fed raised rates

¹³ Chairman Jerome Powell, *Inflation: Progress and the Path Ahead*, delivered at the Structural Shifts in the Global Economy, policy symposium sponsored by the Federal reserve Bank of Kansas City, August 25, 2023.

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1 11 times, to a range of 5.25 percent to 5.50 percent. The current interest rate
2 environment consists of the highest rates in the past 22 years. This rapid increase in rates
3 has strong implications for equity cost of capital, as very low risk bonds now provide a
4 relatively high return by historical standards.
5 Chairman Powell has stated that the neutral rate of interest may be rising,¹⁴ where the
6 neutral rate is defined as the rate of interest which prevails at a non-inflationary full
7 employment level of aggregate output. As mentioned, estimates clearly suggest the
8 neutral rate has declined significant in the most recent years, as shown in Figure 3,
9 below. However, estimates of this rate have notched up in recent months.

**Figure 3: Trends in the Natural Rate of Interest
U.S., Western Europe, and the U.K.¹⁵**



¹⁴ <https://www.brookings.edu/articles/the-hutchins-center-explains-the-neutral-rate-of-interest/>

¹⁵ Holston, Laubach, and Williams. 2023. "Measuring the Natural Rate of Interest after COVID-19," Federal Reserve Bank of New York Staff Reports, no. 1063, June.

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1 **Q. How does fiscal policy influence capital markets?**

2 A. Fiscal policy also affects private investment positions, not just within the United States
3 but internationally. Increased deficit spending in the United States, along with natural
4 fluctuations in funding needs relative to tax revenue, requires the Treasury department to
5 issue debt securities in the form of Treasury bills and bonds. These debt issuances are
6 considered to be among the most secure bonds available in the global marketplace,
7 providing a near risk-free security for investors. As a result, large issuances of U.S. debt
8 securities, particularly when issued at higher rates, can result in “crowding out” of other
9 investment instruments.¹⁶ Competition with Treasury securities can create challenges for
10 private sector firms to attract capital. In addition, demand for capital by the U.S.
11 Treasury has been met with somewhat muted enthusiasm in recent auctions.¹⁷ Figure 4
12 depicts the growth of U.S. public debt, in 1990 dollars, showing that the real value of
13 U.S. debt has grown nearly five-fold in the past three decades. In nominal terms, the
14 U.S. Congressional Budget Office projects U.S. *deficit* levels will reach \$\$1.6 trillion in
15 2024 and increase up to \$2.6 trillion by 2034.¹⁸ Although the myriad consequences of
16 this escalation of debt is difficult to predict, economic principles clearly herald an
17 increase in real interest rates, leading to a challenging environment for private
18 investment.

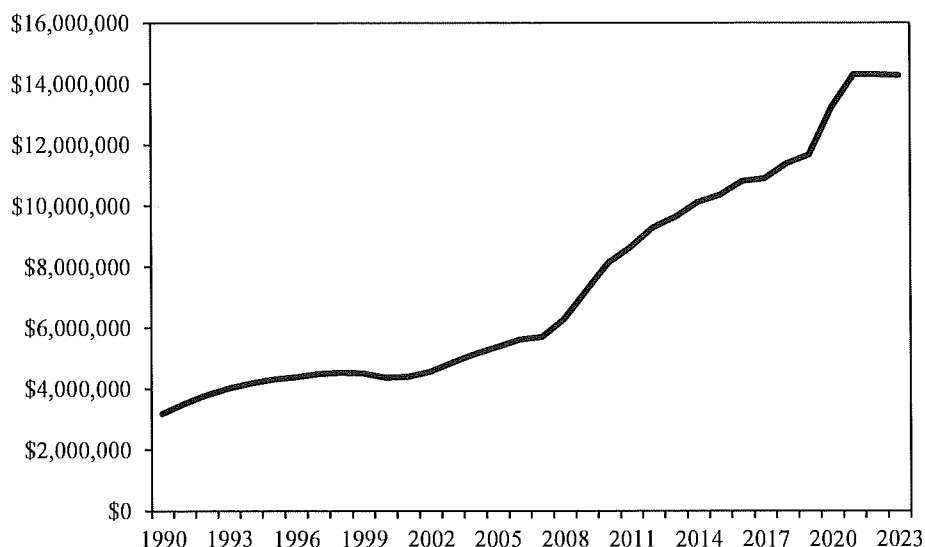
¹⁶ *Macroeconomics*, Gregory Mankiw, Seventh Edition, 2009, p. 69.

¹⁷ <https://www.bloomberg.com/news/articles/2024-05-28/treasuries-steady-before-debt-auction-rush-and-inflation-data>

¹⁸ <https://www.cbo.gov/publication/59710>

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Figure 4: Real Value of U.S. Public Debt (in 1990 Dollars)



Heightened government spending by the U.S. and western economies is expected to continue. A component of increased spending arises from recent policy initiatives by the U.S. and Western Europe proposing to embark on a major structural overhaul including large scale investment focused on:

- climate change mitigation, particularly as it relates to electric utility operations;
- improved efficiency in transportation sectors;
- further development of human capital within the labor force;
- advanced information technologies; and,
- much improved access to information systems in less developed regions.

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1 **Q. Could you please summarize how monetary and fiscal policy affect utility cost of**
2 **capital?**

3 A. Consideration of the factors discussed above portend substantial demand for capital,
4 elevated risk-free interest rates, relative to recent history, and a sustained rate of inflation
5 above 2.0 percent in the coming years.¹⁹ Taken as a whole, the above considerations
6 suggest that, on balance, interest rates and the risk-adjusted cost of capital during the
7 2024-2026 years likely understate aggregate demand and related conditions that are
8 likely to prevail over near-term future years; namely:

- 9 • comparatively low natural rate of interest, as viewed with respect to
10 recent decades;
- 11 • monetary policy that faces continued inflationary pressures, making it
12 difficult to bring average inflation to 2.0 percent; and,
- 13 • considerable demand for capital, particularly in light of contemporary
14 long-term demand for renewable resources; infrastructure; and challenges
15 containing the secular rise in the primary deficits across developed
16 western economies.

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¹⁹ The relevant three factors can be summarized as *very high levels of precaution balances of cash and equivalents; major expansion of fiscal expenditures in the U.S. and Western Europe to fund investment in public goods; and Flexible Inflation Targeting.*

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1 **5. Cost of Debt Analysis**

2 ***5.1 Long-Term Debt Issuances***

3 **Q. Please define the term “long-term debt.”**

4 A. Generally speaking, long-term debt refers to the outstanding debt obligations with a
5 duration beyond one year. At one time, the long-term debt of the U.S. corporate sector
6 including public utilities consisted largely of corporate bonds held directly by investors,
7 and long-term loans with commercial banks. Over the past two decades, however, an
8 array of non-bank intermediaries including finance companies, broker/dealers, insurance
9 companies, pension funds, ETFs, mutual funds, private investment pools, and asset-
10 backed securities supplement these conventional sources and, these days, provide much
11 of the long-term debt used by corporate organizations and private companies, both in the
12 U.S. and abroad.

13 **Q. What is the benefit of issuing long-term debt to fund long-term investments?**

14 A. Lending by intermediaries constitutes private placement, in lieu of new debt issues sold
15 broadly within primary security markets. Like other utilities, Chesapeake and operating
16 utilities including Florida Public Utilities Company are taking advantage of the larger
17 range of borrowing opportunities to underwrite its investment in long-term physical
18 assets. The advantages are twofold. First, underwriting costs including legal fees, and
19 charges for security registration are dramatically reduced. Second, execution time is
20 significantly reduced, allowing parties to the transaction—e.g., an insurance company
21 and a public utility—to better facilitate new debt issues within the larger schedule of
22 other primary market offerings. Third, provisions of new issues, such as secured

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1 collateral, and the schedule for paying down the principal can be more easily tailored to
2 the needs of the parties, particularly borrowing entities such as utilities.

3 **Q. What are the costs associated with issuing and holding long-term debt?**

4 A. The carrying charge rate for long-term debt is determined on a weighted average basis
5 across the outstanding balance of individual issues, measured on a 13-month basis. For
6 each issue, the charge rate (or interest rate) includes coupon interest charges on the
7 outstanding principle plus the amortization of the issuance costs incurred at the time of
8 origination. The total charges are adjusted for requisition costs and the maintenance of
9 fees on shelf agreements.

10 **Q. What are the existing long-term debt obligations of FPUC?**

11 A. For test year 2025, FPUC's long-term debt consists of the 22 outstanding issues of
12 promissory notes of Chesapeake, with durations ranging from two to twenty years. In
13 accordance with internal financial policy, Chesapeake has put in place fairly long-
14 duration notes during recent years, as both nominal and real interest rates were
15 remarkably low, when viewed with respect to the longer-term history of U.S. financial
16 markets. For example, during the years late-2013 through early-2022, Chesapeake
17 originated eleven new promissory note issues, raising a total of \$600 million at face
18 interest rates from as low as 2.49 percent to a high 3.98 percent, with times to maturity
19 between 15-20 years. For reference, the yield on outstanding issues included within
20 Moody's Baa Bond index range from 3.16 percent to 5.46 percent for this period,
21 averaging 4.39 percent. Notes at interest rate levels have specific retirements schedules.

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1 The outstanding principal on long-term debt issued in late-2023 is reduced by nearly 80
2 percent, as only a modest share of the late-November issues are attributable to FPUC's
3 electric operations.

4 **Q. What is the context of FPUC's debt cost rates?**

5 A. As a consequence of the rapid tightening of monetary policy, short- and long-term
6 interest rates rose dramatically worldwide beginning in the spring of 2022. As a result,
7 most of Chesapeake's long-term debt issues originating in late-November 2023, used
8 predominantly to finance its acquisition of Florida City Gas, have relatively short terms
9 to maturity—seven years or less. Chesapeake—and financial markets, generally
10 speaking—anticipates that over years 2026—2030, both short- and long-term interest
11 rates will decline from recent high levels. Chesapeake will then be in the position of
12 largely supplanting the comparatively high-cost issues of late-November 2023 with
13 lower cost long-term debt. Moreover, in fairness to its retail electricity customers, only a
14 modest share (21 percent) of the comparatively high-cost rate promissory notes of late-
15 November 2023 are used to determine the overall cost rate for long-term debt
16 attributable to FPUC's electric operations.

17 **Q. Why is FPUC's requested cost of long-term debt lower than Chesapeake's**
18 **consolidated cost of long-term debt?**

19 A. FPUC requests recovery of an attenuated cost of long-term debt relative to Chesapeake's
20 actual embedded cost of long-term debt. The Company has removed from the long-term
21 debt interest rate calculation a portion of long-term debt costs associated with
22 Chesapeake's purchase of Florida City Gas Company ("Florida City Gas"). With a

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1 portion of these proceeds used to finance the acquisition during a period of elevated
 2 interest rates and considering the overall operational benefits across the entire enterprise
 3 the Company is requesting the inclusion of approximately 21 percent of these senior
 4 notes to determine the overall long-term interest rate for purposes of this rate case filing.

5 By removing a portion of these costs from the cost rate requested for recovery, FPUC
 6 has reduced its requested long-term debt cost recovery, and, consequently, the
 7 Company's overall requested WACC rate.

8 **Q. Please provide FPUC's long term debt cost rates for the historical, current, and test**
 9 **period years.**

10 A. FPUC's long-term debt cost rates for the three reporting years, historical (2023), current
 11 (2024), and test period (2025) are presented in Table 3. These cost rates are based on
 12 FPUC's supplemental schedules, which have adjusted the actual Chesapeake cost of debt
 13 downward. As discussed above, FPUC has requested recovery of an attenuated cost of
 14 long-term debt to reflect only a portion of the debt costs associated with the purchase of
 15 Florida City Gas. The actual cost of debt incurred by Chesapeake is, in fact, higher than
 16 the cost rates in this table.

17 **Table 3: FPUC's Requested Long-Term Debt Cost Recovery Rates (2025)**

Long-Term Debt Cost Rates	
Historical Year (2023)	3.64%
Current Year (2024)	4.12%
Projected Test Year (2025)	4.51%

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1 **5.2 Short-Term Debt Issuances**

2 **Q. What is the definition of “short-term debt?”**

3 A. Short-term debt refers to outstanding debt with less than one-year maturity. Short-term
4 debt can include short-term loans and revolving credit facilities with commercial banks
5 and non-bank financial intermediaries, as well as commercial paper, and possibly short-
6 term repurchase agreements.

7 **Q. How is short-term debt employed?**

8 A. Short-term debt is integral to financial operations, both day-to-day cash management and
9 near-term financial planning. Driven by the variation the revenues and cash outlays,
10 outstanding balances of short-term debt can vary considerably. In the case of electric and
11 gas utilities, flows of revenues are highly sensitive to short-term variation in energy
12 demand, in turn determined by weather. Near-term cash underwrite near-term resource
13 inputs including wages and salaries, operating expenses including invoices for outside
14 services, and the immediate cash requirements of ongoing construction, can vary
15 considerably by day, month, and season. Short-term debt can also be used to bridge
16 long-term external financial events including the issuance of common stock and long-
17 term debt.

18 **Q. What is the condition of FPUC’s short-term debt liabilities?**

19 A. The short-term debt of Chesapeake consists of a multi-tranche lending facility with a
20 borrowing limit of \$250 million for the first-tier tranche (364 day). The second-tier
21 tranche (5-year) borrowing limit is \$200 million, providing a total of \$450 million in
22 short-term revolving credit for general use. In addition, the facility has accordion

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1 features, providing an additional \$150 million borrowing capacity. In summary,
2 Chesapeake has \$600 million of short-term and medium-term debt capacity under
3 current arrangements in place with major lending institutions.

4 **Q. What are the terms of FPUC's short-term debt?**

5 A. The commercial terms of Chesapeake's short-term debt include use-of-facility and non-
6 use commitment fees. The use-of-facility interest charges on "draw down" amounts are
7 based on the Secured Overnight Financing Rate ("SOFR"), as published daily by the
8 Federal Reserve Bank of New York. The first-tier tranche interest charges equal the
9 daily SOFR interest rate plus 90 basis points, whereas charges for draw-down amounts
10 on the second-tier tranche is set according to the daily SOFR interest rate plus 110 basis
11 points. Commitment fees on unused capacity is equal to 10 basis points, for both first-
12 and second-tier tranches.

13 **Q. How do the terms of FPUC's short-term debt align with current conditions in debt**
14 **markets?**

15 A. At this writing, the contemporary outlook calls for the FOMC policy rate of 5.25-5.50%
16 to, most likely, reduce the policy rate by just a single step of 25 basis point through the
17 end of 2024. This Federal Reserve policy outlook underlies Chesapeake's expectations
18 and is reflected in the short-term debt cost rate for test year 2025. Stated on a 13-month
19 weighted average basis, the charge rate for Chesapeake's short-term debt was 5.35% for
20 2023, rising to 6.42% for the current year 2024, and is expected to decline to 5.81% for
21 test year 2025.

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1 **6. Cost of Equity Estimation Methods**

2 **Q. What is the basis for FPUC's cost of equity estimations?**

3 A. The cost of common equity is based upon the observed market experience of the
4 common equity shares of samples of companies traded on U.S. financial markets. It is
5 useful to reiterate three essential points that were mentioned above. First, the cost of
6 equity of the firm—opportunities costs incurred by investors in the firm—is a function
7 of perceptions of risk, the demand for and supply of capital, and expectations of
8 inflation. Second, the cost of common equity of the firm is equal to the opportunity cost
9 of capital incurred by common shareholders of the firm contemporaneously, though the
10 experience of long-term history guides the assessment of opportunity costs. Third, the
11 cost of equity of the firm is equal to the expected market rate of return on alternative
12 investments of comparable risks available to shareholders—i.e., the opportunity cost of
13 capital—within a contemporary timeframe.

14 **Q. How does the cost of equity recommendation methodology differ from the**
15 **approach used to determine the cost of debt?**

16 A. In the case of debt, both the market price and future expected cash flow returns to
17 capital, in the form of dividend payments, are observable by inspection. Thus, the net
18 expected yield to maturity, which reflects the opportunity cost of capital to holders of
19 debt, can be determined directly. This is the market rate of return, ex ante. For purposes
20 of determining the overall utility rate of return, the cost rate of long-term debt is that
21 which is set at the time of issuance in primary financial markets.

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1 In contrast, expectations of investors about the prospective cash flows and market
2 returns on common equity cannot be observed. Cost of equity must be discerned through
3 the proper and careful application of well-established financial frameworks. Also, the
4 allowed equity rate of return is typically set according to the current and expected cost of
5 capital, though much of the equity investment was committed in many years past. That
6 is, the cost of equity may change over time as market conditions change, even though the
7 original equity contribution has been in place for some time.

8 **Q. What are the cost of equity estimation models used in this study?**

9 A. In order to develop our recommendation for the rate of return on equity for FPUC, I
10 apply four cost of capital methods. These estimation procedures include variants of the
11 constant growth Discounted Cash Flow model (DCF), and the Capital Asset Pricing
12 Model (CAPM). These classical approaches are commonly recognized within modern
13 finance theory and are readily utilized for purposes of capital valuation. The results of
14 these two formal models of the cost of capital are augmented by an assessment of Risk
15 Premia analysis and Realized Market Returns for utility and non-utility companies of
16 comparable risks.

17 **Q. Please describe the Discounted Cash Flow (“DCF”) model in further detail.**

18 A. The constant growth Discounted Cash Flow model was originally developed by Myron
19 Gordon in 1957 and was broadly applied during the following decades. In its classic,
20 one-stage form, the derived DCF model defines the cost of capital as the sum of the
21 adjusted dividend yield, and expectations of future growth in cash flows to investors,

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1 including dividends and future appreciation in share prices. The classic DCF model is as
 2 follows:

$$3 \quad K_{e,j} = \frac{D_{0,j} (1 + E(g_j))}{P_{0,j}} + E(g_j)$$

4 with,

5 $K_{e,j}$ = cost of equity capital for asset j

6 $D_{0,j}$ = current dividends per common share for asset j

7 $E(g_j)$ = expected growth in future cash flow returns to investors in asset j

8 $P_{0,j}$ = current price per common share for asset j

9 The one-stage form of the DCF approach is elegant and intuitively tractable. As shown
 10 above, the model includes two terms, a mathematical result derived from the general
 11 form of discounted present value, as applied to a series of benefits over time
 12 characterized by uniform growth. A cursory review of historical returns on equities
 13 suggests that differences in the observed internal returns to capital, as well as
 14 expectations of future returns as expressed by security analysts, contribute to realized
 15 market appreciation as well as to the total returns to capital. It is plausible that the
 16 expected path of future returns harbored by investors may assume a pattern of non-
 17 constant growth.

18 **Q. Please explain the Capital Asset Pricing Model (“CAPM”).**

19 A. The Capital Asset Price Model (CAPM) was developed by William Sharpe (1961) and
 20 John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular,
 21 portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how

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the valuation of a financial asset (price) is based upon two components: risk-free returns and an adjusted risk-based return. Surrogates for risk-free returns can be observed directly in capital markets, including market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns on government debt obligations serve as appropriate surrogates.

The adjusted risk-based return is based upon three factors: 1) the covariation of the returns of the asset and that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the difference between expected overall returns on risky assets, and risk-free returns. The third parameter is referred to as the excess return and is equal to the difference between the overall returns to risky assets for equity markets as a whole and the risk-free return rate. The CAPM is shown below:

$$K_{e,j} = r_{free} + \beta_j * (r_{market} - r_{free})$$

with,

$K_{e,j}$ = cost of equity capital for risky asset j, stated in percentage terms

r_{free} = risk-free rate of return

β_j = asset beta; the ratio of the covariation between risky asset j and the market as a whole and the variance of market returns

r_m = expected rate of return on equity markets, as a whole

Q. What are the assumptions supporting the DCF and CAPM approaches to estimating the cost of equity?

A. The determination of the cost of equity capital faces two overarching assumptions, as follows:

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- both approaches are forward looking and thus the results are highly dependent upon useful estimates of investor expectations about future market performance.
- the underlying assumptions for DCF and CAPM include, among other things, an efficient market and rational behavior of investors such that all opportunities for above- and below-normal returns to capital are exhausted on an expected value basis. In short, capital markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

Q. What is the “Risk Premia” approach to estimating the cost of equity?

A. The underlying concept of the risk premia approach is that differences in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns, referred to as risk premia, serve as a surrogate for the compensation for risk over future timeframes. When combined prospectively with the expected cost of short-term debt, risk premia provide a useful benchmark to gauge the underlying cost of equity capital. The immediate application of the Risk Premium approach is codified as follows:

$$K_{e,j} = r_{free}^{st} + rp_{int-st} + rp_{m-nit} + rp_{y-m}^{CAPM} + rp_{free}^{size}$$

with,

$K_{e,j}$ = cost of equity capital for risky asset j, stated in real terms

r_{free}^{st} = risk-free rate of return, for a short-term asset

rp_{int-st} = risk premium for intermediate-term asset relative to a short-term

asset

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1 rp_{m-int} = risk premium for equity market m relative to an intermediate-term
2 asset

3 rp^{CAPM}_{y-m} = risk premium for industry y with respect to equity market m, where y
4 refers to the relevant industry sample²⁰

5 **Q. What are the potential drawbacks or pitfalls of the Risk Premia approach?**

6 A. Application of the Risk Premia approach contains two potential pitfalls:

- 7 • The opportunity cost of common equity capital, stated in nominal terms, is
8 sensitive to the demand for and supply of capital; and,
9 • Risk premia among debt and equity instruments are also sensitive to expected
10 inflation. Thus, risk premium analysis must account for expected inflation in
11 the future. That is, the underlying rate of inflation and conditions of the
12 historical period over which risk premia are estimated must match those of
13 the expected conditions of the relevant period over which the common equity
14 recommendation is being applied, and over which retail electricity prices are
15 being set.

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20 Cost of capital can be highly specific to industry, and it thus appropriate to incorporate this factor to account for industry-specific risks, generally speaking. However, the selection process incorporated within the immediate analysis implicitly normalizes for industry specific risks by concentrating on a sample of electric and gas utilities. Hence, the factor for industry specific risks is zero.

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Q. Please describe how “Realized Market Returns” are used in the return on equity recommendation.

A. Measurements of Realized Market Returns and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that all financial assets are priced at levels such that the expected future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the Realized Market Returns methodology can be viewed as a market-based approach of Comparable Earnings, and thus fully satisfies the Bluefield and Hope criteria. More specifically, realized market return for a period is defined as:

$$R_{j,t-(t-1)} = (P_{j,t} + D_{j,t-(t-1)} - P_{j,t-1}) / P_{j,t-1}$$

with,

$R_{j,t-t-1}$ = market return realized within the interval $t - t-1$, for financial asset j

$D_{j,t-t-1}$ = dividends paid during the interval $t - t-1$, for financial asset j

$P_{j,t,t-1}$ = market value of financial asset j , at t and $t-1$

The successfully application of this fourth approach is identification and measurement of historical returns in a manner that reasonably reflects expectations of investors with respect to the contemporary outlook.

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1 **Q. Why are realized market returns useful for supporting a cost of equity**
2 **recommendation?**

3 A. Observed historical returns and future expected returns of financial assets are ordered
4 according to risks. This ordering is a natural and inevitable result of competitive
5 financial markets: because risk is costly, higher costs must be offset by higher returns.
6 While it is not based upon an explicit model, the analysis of the risk among classes of
7 risky assets provides a means to infer the underlying opportunity cost of capital.

8 **7. Cost of Equity Results**

9 ***6.1 Data and Proxy Group Selection***

10 **Q. What is the general approach to your cost of equity analysis?**

11 A. The cost of capital estimates draw on the universe of private companies listed with U.S.
12 capital markets, including the NASDAQ Stock Market (“NASDAQ”) and New York
13 Stock Exchange (“NYSE”), as a starting point from which to select comparable risk peer
14 groups of utilities and non-utility companies. Once selected, the cost of common equity
15 is estimated for the peer group sample companies. A distinguishing factor of
16 comparability is market size. As discussed above, empirical evidence convincingly
17 demonstrates that the cost of capital rises as the relative capitalization of firms declines,
18 other factors held constant.

19 **Q. What are the sources of data for the cost of equity study?**

20 A. The cost of equity study utilizes data from several information sources including
21 Morningstar, Kroll, Value Line, UBS Financial Services, the Center for Research in
22 Securities Prices (“CRSP”), Yahoo Finance, Trading Economics, and Zacks Financial

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1 Services. For the selected entities, an array of financial data, business descriptions and
2 classifications, excerpts from financial statements, historical price experience, and
3 various diagnostic statistics of interest are reported by these data sources. Specifically,
4 common equity shares of the comparable risk entities are traded on the NASDAQ and
5 NYSE exchanges. NASDAQ and NYSE listings constitute large shares of worldwide
6 equity markets, along with commensurate levels of transaction liquidity. Movements and
7 performance of the indexes for the North American markets often parallel movements of
8 share prices reflected within other world indexes, though differences are observed as a
9 result of currency exchange rate movements, unanticipated random social and physical
10 events within regions, and significant changes in expectations of economic performance
11 across various regions worldwide.

12 **Q. Please describe the selection process for the utility proxy group.**

13 A. To obtain cost of equity estimates for FPUC, it is necessary to look to a group of
14 publicly traded companies (“Utility Proxy Group”) for comparable estimates that can be
15 utilized to determine the Cost of Equity for the Company. The cost of capital methods
16 used herein coupled with evidence from international cost of capital studies suggest that,
17 particularly for contemporary capital markets with high levels of international capital
18 flows, selection according to observable market and financial risk metrics are the
19 predominant selection criterion. Line of business appears to have only a modest level of
20 relevance to cost of capital once market and financial criteria are satisfied. Thus, it is
21 appropriate, for determining the allowed return on equity, to draw samples from a broad
22 range of business fields once comparable risk criteria are satisfied. The cost of capital

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1 study utilizes two common-business- line samples (electric and gas), adhering to
2 standard regulatory practices. In addition, cost of equity estimates were developed for a
3 separate sample of low-risk non-utility entities for comparison purposes.

4 From the U.S. market portfolio, I developed two utility company samples and a sample
5 of moderately-sized, comparable risk non-utility companies. The first sample, Moderate-
6 Sized Electric Utilities (Sample 1), is limited to retail electricity service providers that
7 have modest yet significant levels of market participation and, as a matter of business
8 line, parallel FPUC. The second utility sample is referred to as the Gas Distribution
9 Utilities (Sample 2), and is composed of retail natural gas service providers in the U.S.
10 Our studies demonstrate that, as a practical matter, the level of capital risks and thus the
11 opportunity cost of capital is comparable for the two samples. For purposes of
12 comparing the equity rate of return requirements of FPUC, the study compares the gas
13 and electric utility results with a third U.S. sample, referred to as Comparable Risk Non-
14 Utility Companies (Sample 3).

15 **Q. What is the universe of firms used to select the utility proxy group?**

16 A. To determine Sample 1, the study begins with a review of the sector including 75
17 electric utility and electric energy companies. From this initial selection, 15 electric
18 utility companies are selected for potential use in cost estimation. Some of these 15
19 companies are also engaged in non-electric retail business lines including natural gas
20 services, and such activities provide moderate contributions to the total return on capital.
21 It is virtually impossible these days to assemble a sizable set of electric companies that

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1 are exclusively retail electric utilities—sometimes referred to as a pure play. However,
2 Sample 1 electric utilities comprise entities where electric power supply and delivery is
3 the dominant share of business activity. Non-utility activities should not matter in a
4 measurable way, providing that such activities are of modest scale; indeed, endeavors to
5 diversify risk over alternative business lines may reduce variation in earnings in internal
6 cash flow though not necessarily variation in market returns. Variation in overall
7 investment risk, and thus the cost of capital may not increase, at least measurably.
8 Sample 1 electric utilities range from less than \$1.0 billion (Unitil) to over \$12.1 billion
9 (Evergy) in total capitalization for year-end 2023, with similar differences in operating
10 revenues and total net plant.

11 **Q. What criteria was used to select the proxy group from the universe of publicly**
12 **traded electric utilities?**

13 A. I have followed a set of criteria that selects a group of companies that reflect the FPUC's
14 operations, while allowing for an assessment of risk through the use of market data. As
15 such, I have selected my proxy group based on the following criteria:

- 16 • Equity Participation in total capital;
- 17 • Consistent quarterly dividends;
- 18 • Market capitalization below \$30 billion;
- 19 • Positive long term earnings growth forecasts from at least two sources;
- 20 • Investment grade issuer ratings from S&P and Moodys;

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- 1 • *CAPM Beta* which, as discussed above, is the ratio of the covariation of the
- 2 market returns of a specific stock of a company and the market as a whole,
- 3 and the statistical variance of the returns of the market; and,
- 4 • *Variation in Market Returns measured as the* coefficient of variation in
- 5 monthly market prices. To a lesser extent, abrupt changes and suspension of
- 6 dividends has impact on realized returns.

7 These criteria above resulted in the following Utility Proxy Group of 15 companies.

8 While moderate in size by U.S. standards, the Sample 1 electric utilities reflect a

9 comparatively broad size range.

10 **Q. What was the criteria used to determine the proxy group for gas utilities?**

11 A. The selection process for the U.S. Gas Distribution Utilities (Sample 2) is similar to

12 methodology used to determine Sample 1 (Moderate-Sized Electric Utilities): a sample

13 is first drawn on the bases of market liquidity and business line. The initial set of natural

14 gas utilities and energy companies includes 18 entities. From this initial draw,²¹ six gas

15 distributors were retained for the analysis. The gas distribution utilities range in size

16 from approximately \$1.66 billion (Northwest Natural Holding Company) to well over

17 \$15.0 billion (Atmos Energy Corporation). For 2023, the natural gas utilities have

18 similar unadjusted CAPM betas (0.76) as the selected electric utilities (0.83) and

²¹ The U.S. natural gas industry includes many regional and national distributors of liquid propane and specialty industrial gas products and services, such as Penn Octane Corporation, Suburban Propane Partners, and Continental Fuels Inc.

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1 somewhat lower variation in market returns (0.116) compared to the electricity utility
2 sample (0.159).

3 **Q. How were the comparable non-utility companies selected?**

4 A. The comparable risk non-utility companies (Sample 3) were drawn from across non-
5 utility economic sectors excluding financial services, providing that market
6 capitalization was less than \$2 billion and average market beta was less than unity.
7 These criteria netted some 75 entities. The study methodology preferred for entities of
8 Sample 3 to finance their respective balance sheets with some level debt, though several
9 entities within Sample 3 are financed exclusively with equity. The selection screen
10 required equity participation, CAPM beta information, variation in market returns, and
11 variation in earnings per share—e.g., internal business and financial risk—obtained 14
12 entities which together constitute the comparable risk non-utilities.

13 ***6.2 Capital Asset Pricing Model Results***

14 **Q. What are the basic principles of the CAPM approach to estimating the cost of**
15 **equity?**

16 A. The CAPM model involves three inputs including estimates of the risk-free cost of
17 capital, expectations of future returns to equity markets as a whole, and CAPM beta, the
18 ratio of the covariance of share prices/market to the variance of overall market returns.
19 Consistent with theory and conventional practice, it is appropriate to match up the risk-
20 free rate of interest with the duration of investment undergoing capital valuation. The
21 physical facilities of FPUC, like that of all electric utilities, are unusually long-lived
22 compared to capital assets in other industries. Accordingly, for the cost of capital study,

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1 the risk-free rate is set equal to the forward-looking dividend yields on 30-year U.S.

2 Treasury Securities (constant maturity). Specifically, the risk-free rate is equal to the

3 average monthly yield on 30-year U.S. Treasury securities (constant maturity) for two

4 timeframes including 2013-2023 and 2021-2023, observed in monthly frequency.

5 Estimates of future returns for equity markets (i.e., overall market return) are based on

6 historical realized returns for U.S. markets, measured in real terms. Once estimated, the

7 observed real rate of return for equity markets is adjusted upwards for expected inflation

8 of 2.46 percent.²² Real rates of return are calculated as the arithmetic average of annual

9 returns over two timeframes, 1970 through 2023, and 1990 through 2023. These results

10 are then adjusted to account for current expectations of inflation.

11 **Q. From what source are the CAPM betas used in this analysis obtained?**

12 A. The CAPM betas for the selected electric utilities, gas distributors and comparable risk

13 non-utility companies are culled from Morningstar and Yahoo Finance. Morningstar

14 estimates CAPM betas in monthly frequency over five years. Estimated betas are then

15 adjusted for central tendency based on the methodology pioneered by Marshall Blume.

16 For this study, CAPM estimates of the cost of equity use the average of the estimated

17 betas over the five years 2019-2023.

18 **Q. Please provide the results of your CAPM analysis.**

19 A. CAPM estimates of the cost of equity can be found in Table 4, below.

²² The cost of equity study takes note of contemporary expectations of inflation of the investment community, as measured by the difference in the long-term yields between constant maturity and Treasury Inflation protection security, of 2.46 percent.

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Table 4: CAPM Results

<u>Sample 1: Moderate-Sized Electric Utilities</u>				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.39%	3.39%	0.97	10.63%
High	11.61%	4.31%	1.00	11.62%
Weighted Average	11.18%	3.85%	1.01	11.13%
<u>Sample 2: Natural Gas Distribution Utilities</u>				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.14%	3.39%	0.93	10.63%
High	11.31%	4.31%	0.96	11.62%
Weighted Average	10.72%	3.85%	0.94	11.13%
<u>Sample 3: Small Non-Utilites</u>				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.10%	3.39%	0.93	10.63%
High	11.63%	4.31%	1.00	11.62%
Weighted Average	11.29%	3.85%	1.02	11.13%

6.3 Discounted Cash Flow Results

Q. Over what time period is the DCF methodology applied in this study?

A. The *Discounted Cash Flow* methodology is applied to the moderate-sized electric utilities (Sample 1) and gas distribution utilities (Sample 2). DCF cost estimates are based on investor expectations reflected in the market prices of the two samples during May of each year, 2021-2023. That is, under the assumption of efficient markets, the study anticipates that investors “price in” relevant information including perceptions of risks and expectations for future market performance. This multiple sample approach covering three contemporary years is carried out for each of the selected electric utilities and gas distributors which together constitute Samples 1 and 2. For each year’s draw of prices, investors have available multiple years of historical financial data including the

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1 earnings, internal cash flow, and dividend experience up through and including
2 December of the previous year. The discounted cash flow analysis, as applied in the
3 current study, is the classic constant growth expectations methodology, where
4 expectations are based on historical experience.²³

5 **Q. What are the results of the discounted cash flow analysis for electric utilities?**

6 A. The derived form of the discounted cash flow model consists of the dividend yield for
7 the forward year plus estimates of the expectations for near- and long-term change
8 (growth) in cash flows, with both terms expressed as percent values. Results of the
9 discounted cash flow analysis, as applied to the moderate-sized electric utilities (Sample
10 1) and gas distribution utilities (Sample 2) are shown in Table 5, below. As shown, the
11 unadjusted DCF estimates for the Moderate-Sized Electric Utilities (Sample 1) range
12 from 8.45 percent to 10.79 percent.

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23 Because of inherent challenges associated with gauging the long-term path of cash flows, the methodology underlying the current study does not generally apply multi-stage DCF procedures, for assessment of capital investment within small sovereign regions.

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Table 5: Electric Utility DCF Results (2021-2023)

<u>2021</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.98%	5.15%	8.45%
High	3.66%	7.39%	10.73%
Weighted Average	3.36%	6.33%	9.69%
<u>2022</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	3.12%	5.39%	8.93%
High	3.94%	7.26%	10.79%
Weighted Average	3.42%	6.35%	9.77%
<u>2023</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	3.10%	5.28%	8.51%
High	3.93%	6.80%	10.60%
Weighted Average	3.53%	5.84%	9.37%

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3 **Q. Please provide the results of the DCF analysis of gas utilities.**

4 A. The risk profiles of the natural gas distribution utilities (Sample 2) closely parallel the
5 profiles of the moderate-sized electric utilities. Accordingly, the cost of equity estimates
6 of the two samples are similar in the case of the gas distributors. Unadjusted DCF cost
7 estimates range from 8.48 percent to 13.75 percent and on a weighted average basis,
8 9.55 percent to 12.08 percent. Presented below are the discounted cash flow estimate for
9 the gas distribution utilities (Sample 2).

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Table 6: Gas Utility DCF Results (2021-2023)

<u>2021</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.40%	7.64%	10.29%
High	3.13%	10.86%	13.75%
Weighted Average	2.78%	9.30%	12.08%
<u>2022</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.42%	7.63%	10.27%
High	3.09%	10.45%	13.32%
Weighted Average	2.77%	9.19%	11.96%
<u>2023</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.85%	4.95%	8.48%
High	3.81%	6.78%	9.91%
Weighted Average	3.09%	6.45%	9.55%

6.4 Risk Premia Analysis Results

Q. What is basis for conducting a risk premia analysis to assess the cost of utility capital?

A. The risk premia analysis is based on the conceptual foundation that risks implicit in financial assets including common equity are differentiated according to risks, across various asset classes. Because investors are generally risk adverse, competitive capital markets ensure that the returns are positively correlated with perceptions of risks and risky asset are ordered according to risk differences among asset classes. The starting point for risk premium analysis is a baseline real cost of capital for risk free assets. Differences in realized returns among financial assets provide the means to estimate the

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1 cost of capital for financial assets of interest: energy utilities situated in the United
2 States.

3 **Q. What is the methodological approach of the risk premia analysis?**

4 A. The risk premia analysis includes the baseline cost of capital for short-term risk free
5 assets, differential return on intermediate term U.S. Treasury securities and short-term
6 risk free assets, the differential return on long-term U.S. Treasury securities and
7 intermediate term securities (U.S. Treasury), and the differential return on U.S. equity
8 markets with reference to long-term U.S. Treasury securities, and adjustment for risk
9 differences between energy utilities and the overall returns on equity market as a whole.

10 **Q. Please provide the results from the risk premia analysis.**

11 A. Table 7, below, shows the risk premia analysis for the electric, gas, and non-utility
12 samples. As shown, the risk premia analysis cost of equity analysis obtains highly
13 similar results for the three sample groups of electric utilities, gas distribution utilities,
14 and small moderate-risk non-utilities. The risk premia cost of equity estimates align
15 with, and thus tend to reinforce, the cost of equity estimates obtained through the other
16 cost of capital tools including CAPM, DCF, and realized market returns.

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Table 7: Risk Premia Analysis Results

	Equity Returns		Real Returns on US Treasury Debt		
	<u>L-Cap</u>	<u>S-Cap</u>	<u>LT US Debt</u>	<u>InT US Debt</u>	<u>T-Bills</u>
2014	11.39%	1.66%	24.62%	3.77%	0.02%
2015	-0.73%	-12.02%	-0.67%	1.89%	0.02%
2016	9.54%	22.04%	1.38%	1.29%	0.20%
2017	19.42%	16.96%	6.36%	1.25%	0.79%
2018	-6.24%	-17.04%	-0.54%	1.53%	1.80%
2019	28.88%	19.52%	12.09%	6.29%	2.14%
2020	16.26%	0.18%	15.19%	7.38%	0.45%
2021	26.89%	34.98%	-5.08%	-2.53%	0.04%
2022	-19.44%	-5.67%	-26.73%	-9.72%	1.43%
2023	24.23%	5.36%	3.16%	4.59%	4.97%
Average	11.02%	6.60%	2.98%	1.57%	1.19%
Overall Financial Markets			Utility Sector Return Requirements		
			Electricity	Natural Gas	Low-Risk Non-Utilities
Approximate Baseline Real					
Return, Risk Free		1.53%	1.53%	1.53%	1.53%
Expected Inflation		2.46%	3.98%	3.98%	3.98%
Differential Cost of Capital for Asset Classes					
Intermediate Term U.S.					
Treasury Securities		0.05%	4.03%	4.03%	4.03%
Long-Term U.S. Treasury					
Securities		1.40%	5.43%	5.43%	5.43%
Risk Premia for Equity Market					
Asset Class		5.83%	11.27%	11.27%	11.27%
Total Return, Equity Capital		11.27%	10.52%	9.90%	11.39%

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1 ***6.5 Realized Market Returns Analysis***

2 **Q. Why have you included a realized market returns analysis in your cost of capital**
3 **study?**

4 A. Realized Market Returns are wholly consistent with fair rate of return statutes and are
5 not burdened with the circularity arguments associated with the use of realized book
6 returns as the basis for the cost of equity capital. Otherwise referred to as historical
7 returns or comparable earnings, realized returns serve as plausible estimates of the cost
8 of equity, providing that the returns reflect competitive financial market experience with
9 adequate liquidity, and second, are measured over an appropriate timeframe. For this
10 cost of equity study, realized returns are reported for the three samples including electric
11 utilities, gas distribution companies, and comparable risk non-utilities. The total market
12 returns include dividends.

13 **Q. What have been the realized market returns for each sample group over recent**
14 **years?**

15 A. Historical realized returns for the three samples are estimated for overlapping ten-year
16 timeframes ending 2020-2023, as shown below. Historical market returns are
17 summarized in the following table.

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Table 8: Realized Market Returns, 2013-2023²⁴

<u>Market Returns: Year Ending 10-Year Averages</u>				
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
<u>Moderate Sized Electric Utilities</u>				
Average Across the Sample	11.57%	12.22%	11.52%	9.65%
2013-2023 Average Unadjusted				11.52%
<u>Natural Gas Utilities</u>				
Average Across the Sample	13.71%	12.81%	12.88%	8.95%
2013-2023 Average Unadjusted				13.21%
<u>Small Non-Utility Companies (5-year avg)</u>				
Average Across the Sample	11.70%	18.49%	-21.60%	17.43%
2013-2023 Average Unadjusted				9.89%

8. Capital Structure Analysis

Q. How does the capital structure of the Company factor into the determination of the appropriate Return on Equity?

A. All else equal, a higher debt ratio increases investor risk. For this reason, companies with high debt levels face a higher required return on equity by investors relative to comparable firms with lower debt ratios. Under such circumstances, an upward adjustment to the estimated cost of equity is required, assuming the firm has a higher proportion of debt than the sample of utilities used to undertake the cost of equity analysis. In the case of FPUC, an adjustment is not required, as FPUC's capital structure is balanced and similar to the sample.

²⁴ The averages for each of the three samples are weighted by market capitalization of the members of each respective sample.

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1 **Q. Have you provided exhibits related to FPUC's proposed capital structure?**

2 A. Yes. Exhibits NAC-2 through NAC-9 set forth the capital structure on an overall
3 consolidated and regulatory basis for test year 2025 and for historical and current
4 periods, 2023 and 2024 respectively. In keeping with regulatory standards set by the
5 Florida Public Service Commission (FPSC), the regulatory capital structure (and the
6 conventional capital structure also) for each period is stated on a 13-month average
7 basis.

8 **Q. What is the capital structure of Chesapeake Utilities Corporation?**

9 A. The consolidated capital structure of Chesapeake Utilities Corporation over recent years
10 reveals remarkably consistent year-over-year balance across debt and equity components
11 as revealed in Table 9, below.

12 **Table 9: Debt-to-Equity Ratio, Chesapeake Utilities Corporation²⁵**

<u>Year</u>	<u>Debt/Equity Balance</u>
2021	1.01
2022	0.95
2023	1.10
2024	1.06
2025	0.96
*Year end capital structure	

13
14 As shown, the debt-to-equity ratio for the consolidated year-end capital structure holds
15 within the range of 0.95 to 1.10 over years 2021 through 2025, even as the total invested
16 capital has increased by over twofold, reflecting the acquisition of Florida City Gas. The
17 narrow range of debt/equity variation over these years reflects sound financial

²⁵ Table data based on the Company's Minimum Filing Requirement Sheet D-2.

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1 management carried out in accordance with defined policy, contributing to the
2 realization of consistent interest coverage. The end result is financial flexibility, enabling
3 the Company to finance new issues of long-term promissory notes and put in place
4 short-term debt lending facilities on favorable terms, lowering the carrying charges on
5 FPUC's rate base as paid by retail customers.

6 **Q. What is FPUC's regulatory capital structure?**

7 A. FPUC's regulatory capital structure reflects similar levels of stability within the debt and
8 equity components. Across other capital items, for example, accumulated deferred
9 income taxes and regulatory tax liability attributable to FPUC's electric operations,
10 FPUC has experienced some variability over years 2023 to 2025. In the case of deferred
11 income taxes, balances decline from \$22 million in 2023 to \$13 million in 2025.
12 Component weights for the regulatory capital structure used to underwrite the rate base
13 of electric operations can be found in Table 10.

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1 **Table 10: Capitalization Shares (13-month Average), Regulatory Capital Structure**
2 **for FPUC’s Electric Operations²⁶**

Capital Component	2023	2024	2025
Long-Term Debt	29.84%	34.40%	37.91%
Short-Term Debt	5.47%	6.62%	4.83%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	37.84%	37.80%	42.82%
Customer Deposits	3.37%	3.18%	2.67%
Deferred Taxes	19.30%	14.27%	8.80%
Regulatory Tax Liability	4.19%	3.72%	2.96%
ITC at Zero Cost Rate	0.00%	0.00%	0.00%
ITC at Overall Cost Rate	0.00%	0.00%	0.00%
Total	100%	100%	100%

3
4 The debt-to-equity ratios of the regulatory and consolidated capital structures are, by
5 design, highly similar: stated on 13-month average basis, the debt-to-equity ratio of the
6 regulatory capital structure varies between 0.93 and 1.10 for years 2023/25.

7 **9. The Weighted Average Cost of Capital**

8 **Q. Please explain the weighted average cost of capital approach used by FPUC in this**
9 **filing.**

10 A. The weighted average cost of capital of FPUC’s Northeast and Northwest divisions is
11 based on Chesapeake Utilities Corporation’s consolidated capital structure, consisting of
12 long-term debt, short-term debt, and common equity. The outstanding balances of these
13 conventional components of capital are scaled to the rate base used by FPUC to provide
14 electricity services and coupled with specific elements of FPUC’s balance sheet

²⁶ Table data from D-1a, 23 supplement; D-1a, 24 supplement; D-1a, 25 supplement.

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1 attributable to electricity operations, including customer deposits, regulatory tax
2 liabilities, accumulated balances of deferred income taxes and investment tax credits.
3 The result is a regulatory capital structure, where the total of the components closely
4 approximates the rate base of FPUC's electric operations.

5 **Q. What is FPUC's current overall weighted average cost of capital?**

6 A. FPUC's WACC can be expressed in terms of a regulatory capital structure and a
7 traditional capital structure. Using the regulatory capital structure, which includes
8 customer deposits, deferred taxes, and regulatory tax liabilities, the requested WACC
9 recovery rate is 6.89 percent. The requested WACC rate is lower than Chesapeake's
10 actual incurred WACC because of the Company's attenuated long-term debt cost
11 recovery (see Section 5 of this testimony for further discussion). If FPUC requested
12 recovery of its actual cost of long-term debt (5.21 percent), the WACC would be higher
13 than what is shown in this table. Using a conventional capital structure, the WACC is
14 7.98 percent. Table 11, below, provides additional details.

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Table 11: FPUC's Weighted Average Cost of Capital, Test Year 2025

<u>EXHIBIT NAC-1</u>				
FLORIDA PUBLIC UTILITIES COMPANY				
OVERALL RATE OF RETURN REQUIREMENTS				
WEIGHTED AVERAGE COST OF CAPITAL: REGULATORY CAPITAL STRUCTURE				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long-Term Debt	\$56,888,413	37.91%	4.51%	1.71%
Short-Term Debt	\$7,255,028	4.83%	5.81%	0.28%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$64,253,557	42.82%	11.30%	4.84%
Customer Deposits	\$4,001,097	2.67%	2.20%	0.06%
Deferred Taxes	\$13,206,708	8.80%	0.00%	0.00%
Regulatory Tax Liability	\$4,448,275	2.96%	0.00%	0.00%
ITC at WACC	\$0	0.00%	7.98%	0.00%
Total	\$150,053,078	100.00%		6.89%
WEIGHTED AVERAGE COST OF CAPITAL: CONVENTIONAL CAPITAL STRUCTURE				
STATED ON A CONSOLIDATED BASIS				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long Term Debt	\$1,331,883,955	44.31%	4.51%	2.00%
Short-Term Debt	\$169,856,296	5.65%	5.81%	0.33%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$1,504,318,384	50.04%	11.30%	5.65%
Total	\$3,006,058,635	100.00%		7.98%

2
3

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1 **10. Summary and Conclusions**

2 **Q. What is FPUC's cost of debt issuances?**

3 A. Chesapeake's consolidated actual long-term debt rate is 5.21 percent, but the Company
4 has requested recovery of a reduced rate. FPUC requests recovery of an attenuated long-
5 term debt issuance cost of 4.51 percent. The Company's short-term debt issuances carry
6 a cost of 5.81 percent.

7 **Q. What is your recommendation for FPUC's allowable return on equity?**

8 A. Using four methodologies across three relevant sample groups, I estimated a required
9 return on equity of 11.30 percent, with a reasonable band of 10.43 percent to 12.21
10 percent based on the estimation method standard deviations. Given these results, I
11 recommend an allowed return on equity of 11.30 percent.

12 **Q. What is FPUC's weighted average cost of capital?**

13 A. Given the cost of debt, the required return on equity, and FPUC's capital structure, the
14 Company's WACC is 6.89 percent assuming the attenuated cost of long-term debt.

15 **Q. Does this conclude your pre-filed direct testimony?**

16 A. Yes.

17

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Appendix 1: Exhibit NAC-1

Nick Crowley

RESUME

April 2024

Address:

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Academic Background:

Master of Science – University of Wisconsin-Madison, 2014, Economics
Bachelor of Arts – University of Wisconsin-Madison, 2012, Economics

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., Jan. 1, 2024-present
Senior Economist, Laurits R. Christensen Associates, Inc., Sept. 1, 2021-Dec. 2023
Economist, Laurits R. Christensen Associates, Inc., 2019-Aug. 31, 2021
Staff Economist, Laurits R. Christensen Associates, Inc., 2016-2018
Economist, Federal Energy Regulatory Commission, 2015-2016

Professional Experience:

I am an expert witness on issues in utility regulation, with an emphasis on rate design, regulatory finance, and productivity measurement. In my time as a consultant, I have testified on behalf of major public utilities in rate proceedings, measured cost of capital and assembled corresponding reports, developed alternative rate designs, and forecasted electricity load for supply planning purposes. I have also performed extensive research for benchmarking purposes using publicly available data. My work includes marginal cost estimation and the development of marginal cost models for major electric utilities. My reports have been filed before regulatory authorities across North America. Prior to joining Christensen Associates Energy Consulting, I served as an Economist at the Federal Energy Regulatory Commission, where I assisted with energy industry benchmarking, market power studies, and the review and evaluation of natural gas pipeline rate cases. I have deep facility with Stata and Excel, in addition to other software packages used in quantitative analysis.

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PUBLIC TESTIMONY

“Rebuttal Testimony,” Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-150, April 26, 2024.

“Direct Testimony of Nicholas A. Crowley,” Nicholas A. Crowley, MS, New Hampshire Department of Energy, Docket DE 23-039, December 13, 2023.

“Direct Testimony of Nicholas A. Crowley,” Nicholas A. Crowley, MS, Michigan Public Service Commission, Case No. U-21488, December 11, 2023.

“Direct Testimony of Nicholas A. Crowley,” Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-150, November 16, 2023.

“Direct Testimony of Nicholas A. Crowley,” Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-80 AND D.P.U. 23-81, August 17, 2023.

“Rebuttal Evidence,” Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission, Proceeding 27388, April 28, 2023.

“Determination of the Third-Generation X Factor for the AUC Price Cap Plan,” Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission Proceeding 27388, January 20, 2023.

“Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS,” Massachusetts D.P.U. 22-22, June 10, 2022.

“Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS,” Massachusetts D.P.U. 22-22, January 14, 2022.

“Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS,” Massachusetts D.P.U. 20-120, April 23, 2021.

“Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS,” Massachusetts D.P.U. 20-120, November 13, 2020.

PUBLICATIONS

“Trends and Drivers of Distribution Utility Costs in the United States: A Descriptive Analysis from 2008 to 2022. *Electricity Journal*. 37 (2024) 107397.

“2022 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark and Aidan Glaser-Schoff)

“2021 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark and Aidan Glaser-Schoff)

“Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution

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Utilities.” *Utilities Policy*. Vol. 72, October 2021. (with Dr. Mark Meitzen)

“2020 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark and Navya Kataria)

“2019 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark)

“2018 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark)

“2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report.” (with Michael Ty Clark and Dan Hansen)

“2017 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates.” (with Michael Ty Clark and Dan Hansen)

“2016 Load Impact Evaluation of Pacific Gas and Electric Company’s Residential Time-Based Pricing Programs: Ex-post and Ex-ante Report for Customers with Net Energy Metering.” (with Michael Ty Clark and Dan Hansen)

“2016 Load Impact Evaluation of Pacific Gas and Electric Company’s Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: Ex-post and Ex-ante Report.” (with Michael Ty Clark and Dan Hansen)

CONFERENCE PRESENTATIONS

“Essentials of Costing: Embedded and Marginal Cost.” With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics*. October 10, 2023.

“Rate Design for Revenue Adequacy and Price Efficiency.” With Bruce Chapman. Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

“Marginal Costs of Electricity Services.” Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

“Introduction to Performance-Based Regulation.” EUCI Workshop. Virtual. May 2023.

“Introduction to Retail Electricity Regulation for FERC Staff.” Federal Energy Regulatory Commission, Office of Energy Market Regulation Training Council. Virtual. February 2023.

“Marginal Costs of Electricity Services.” EUCI Workshop. Virtual. February 2023.

“Rate Design for Revenue Adequacy and Price Efficiency.” Wisconsin Public Utility Institute. *Energy Utility Basics*. October 4, 2022.

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"Rate Innovation for Cooperatives and Public Power." EUCI Workshop. Virtual. March 2022.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. March 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. February 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. November 2021.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute.
Energy Utility Basics. October 2, 2021.

"Rate Design and the Potential Impacts of Covid-19." EUCI Workshop. Virtual. November 17, 2020.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Atlanta, Georgia. March 9, 2020.

"Load Impact Evaluation: *Base Interruptible Program*." DRMEC Spring Workshop, California Public Utilities Commission. April 26, 2019.

"FERC Regulatory Policy and Relevant Environmental Issues, Focusing on the United States Natural Gas Grid," 2015 Energy Hub Conference. Hosted at the University of Wisconsin-Madison.

REPORTS AND WORKING PAPERS

"BC Hydro Performance-Based Regulation Framework," For the British Columbia Hydro and Power Authority." With Dr. Daniel McLeod and Dr. Mark Meitzen. December 21, 2023.

"Long Term Avoided Costs, for assessment of Resource Options Including Conservation Programs and LED Lighting." For Florida Public Utilities Company. 2021.

"Cost of Capital Study." For Grand Bahama Power Company, Ltd. April 15, 2021.

"Cost of Capital Study." St. Croix Valley Natural Gas Company, Inc. June 20, 2019.

"Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029." For Newfoundland and Labrador Hydro. November 15, 2018.

"Cost of Capital Study." Grand Bahama Power Company, Ltd. October 17, 2018.

"Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period." *Federal Energy Regulatory Commission Staff Report*, 2016.

COMPUTER/PROGRAMMING SKILLS: Deep knowledge of Excel and STATA for data analysis; experience with R, SAS, and Python for API data acquisition and manipulation.

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Appendix II: Cost of Capital Exhibits

Exhibit NAC-2: Weighted Average Cost of Capital: Conventional Capital Structure Stated on a Consolidated Basis

WEIGHTED AVERAGE COST OF CAPITAL: CONVENTIONAL CAPITAL STRUCTURE STATED ON A CONSOLIDATED BASIS				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long Term Debt	\$1,331,883,955	44.31%	4.51%	2.00%
Short-Term Debt	\$169,856,296	5.65%	5.81%	0.33%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$1,504,318,384	50.04%	11.30%	5.65%
Total	\$3,006,058,635	100.00%		7.98%

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Exhibit NAC-3: Conventional Capital Structure, Test Year 2025

CONVENTIONAL CAPITAL STRUCTURE: TEST YEAR 2025		
Capital Component	13-Month Average	
	Outstanding Balance, Consolidated Basis	Capitalization Shares
Long-Term Debt	\$1,331,883,955	44.31%
Short-Term Debt	\$169,856,296	5.65%
Preferred Stock	\$0	0.00%
Common Equity	\$1,504,318,384	50.04%
Total	\$3,006,058,635	100.00%

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Exhibit NAC-4: Conventional Capital Structure, Current Year 2024

CONVENTIONAL CAPITAL STRUCTURE: CURRENT YEAR 2024		
Capital Component	13-Month Average	
	Outstanding Balance, Consolidated Basis	Capitalization Shares
Long-Term Debt	\$1,188,404,108	43.64%
Short-Term Debt	\$228,599,377	8.39%
Preferred Stock	\$0	0.00%
Common Equity	\$1,306,085,133	47.96%
Total	\$2,723,088,617	100.00%

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Exhibit NAC-5: Conventional Capital Structure, Historical Year 2023

CONVENTIONAL CAPITAL STRUCTURE: HISTORICAL YEAR 2023		
Capital Component	13-Month Average	
	Outstanding Balance, Consolidated Basis	Capitalization Shares
Long-Term Debt	\$725,924,822	40.79%
Short-Term Debt	\$132,960,125	7.47%
Preferred Stock	\$0	0.00%
Common Equity	\$920,631,947	51.74%
Total	\$1,779,516,894	100.00%

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Exhibit NAC-6: Weighted Average Cost of Capital Regulatory Capital Structure

FLORIDA PUBLIC UTILITIES COMPANY				
OVERALL RATE OF RETURN REQUIREMENTS				
WEIGHTED AVERAGE COST OF CAPITAL: REGULATORY CAPITAL STRUCTURE				
13-MONTH AVERAGE, TEST YEAR 2025				
Capital Component	Outstanding Balances	Capitalization Share	Cost Rate	Weighted Average Cost Rate
Long-Term Debt	\$56,888,413	37.91%	4.51%	1.71%
Short-Term Debt	\$7,255,028	4.83%	5.81%	0.28%
Preferred Stock	\$0	0.00%	0.00%	0.00%
Common Equity	\$64,253,557	42.82%	11.30%	4.84%
Customer Deposits	\$4,001,097	2.67%	2.20%	0.06%
Deferred Taxes	\$13,206,708	8.80%	0.00%	0.00%
Regulatory Tax Liability	\$4,448,275	2.96%	0.00%	0.00%
ITC at WACC	\$0	0.00%	7.98%	0.00%
Total	\$150,053,078	100.00%		6.89%

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Exhibit NAC-7: Detailed Regulatory Capital Structure, Test Year 2025

REGULATORY CAPITAL STRUCTURE: TEST YEAR 2025						
Capital Component	Outstanding Balance, Consolidated Basis	Adjustments	Consolidated System Total	13-Month Average		Capitalization Shares
				Rate Base Pro Rata Allocation	Jurisdictional Capital Structure	
Long-Term Debt	\$1,331,883,955	\$0	\$1,331,883,955	4.27%	\$56,888,413	37.91%
Short-Term Debt	\$169,856,296	\$0	\$169,856,296	4.27%	\$7,255,028	4.83%
Preferred Stock	\$0	\$0	\$0	4.27%	\$0	0.00%
Common Equity	\$1,502,431,540	\$1,886,844	\$1,504,318,384	4.27%	\$64,253,557	42.82%
Customer Deposits	\$4,001,097	\$0	\$4,001,097	100.00%	\$4,001,097	2.67%
Deferred Taxes	\$13,206,708	\$0	\$13,206,708	100.00%	\$13,206,708	8.80%
Regulatory Tax Liability	\$4,448,275	\$0	\$4,448,275	100.00%	\$4,448,275	2.96%
ITC at Overall Cost Rate	\$0	\$0	\$0	100.00%	\$0	0.00%
Total	\$3,025,827,871	\$1,886,844	\$3,027,714,715		\$150,053,078	100.00%

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Exhibit NAC-8: Detailed Regulatory Capital Structure, Current Year 2024

REGULATORY CAPITAL STRUCTURE: CURRENT YEAR 2024						
Capital Component	13-Month Average			Rate Base Pro Rata Allocation	Jurisdictional Capital Structure	Capitalization Shares
	Outstanding Balance, Consolidated Basis	Adjustments	Consolidated System Total			
Long-Term Debt	\$1,188,404,108	\$0	\$1,188,404,108	3.62%	\$43,065,436	34.40%
Short-Term Debt	\$228,599,377	\$0	\$228,599,377	3.62%	\$8,283,993	6.62%
Preferred Stock	\$0	\$0	\$0	3.62%	\$0	0.00%
Common Equity	\$1,304,178,789	\$1,906,344	\$1,306,085,133	3.62%	\$47,329,963	37.80%
Customer Deposits	\$3,983,222	\$0	\$3,983,222	100.00%	\$3,983,222	3.18%
Deferred Taxes	\$17,871,253	\$0	\$17,871,253	100.00%	\$17,871,253	14.27%
ITC at Overall Cost Rate	\$4,662,221	\$0	\$4,662,221	100.00%	\$4,662,221	3.72%
ITC at Zero Cost Rate	\$0	\$0	\$0	100.00%	\$0	0.00%
Total	\$2,747,698,969	\$1,906,344	\$2,749,605,313		\$125,196,088	100.00%

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Exhibit NAC-9: Detailed Regulatory Capital Structure, Historical Year 2023

REGULATORY CAPITAL STRUCTURE: HISTORICAL YEAR 2023						
Capital Component	13-Month Average			Rate Base Pro Rata Allocation	Jurisdictional Capital Structure	Capitalization Shares
	Outstanding Balance, Consolidated Basis	Adjustments	Consolidated System Total			
Long-Term Debt	\$725,924,822	\$0	\$725,924,822	4.80%	\$34,811,456	29.84%
Short-Term Debt	\$132,960,125	\$0	\$132,960,125	4.80%	\$6,376,054	5.47%
Preferred Stock	\$0	\$0	\$0	4.80%	\$0	0.00%
Common Equity	\$918,729,847	\$1,902,100	\$920,631,947	4.80%	\$44,148,563	37.84%
Customer Deposits	\$3,930,084	\$0	\$3,930,084	100.00%	\$3,930,084	3.37%
Deferred Taxes	\$22,517,273	\$0	\$22,517,273	100.00%	\$22,517,273	19.30%
Regulatory Tax Liability	\$4,883,526	\$0	\$4,883,526	100.00%	\$4,883,526	4.19%
ITC at Zero Cost Rate	\$0	\$0	\$0	100.00%	\$0	0.00%
ITC at Overall Cost Rate	\$0	\$0	\$0		\$0	0.00%
Total	\$1,808,945,676	\$1,902,100	\$1,810,847,776		\$116,666,955	100.00%

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Exhibit NAC-10: CAPM Estimates of the Cost of Common Equity, U.S. Equity Markets

Sample 1: Moderate-Sized Electric Utilities				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.39%	3.39%	0.97	10.63%
High	11.61%	4.31%	1.00	11.62%
Weighted Average	11.18%	3.85%	1.01	11.13%
Sample 2: Natural Gas Distribution Utilities				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.14%	3.39%	0.93	10.63%
High	11.31%	4.31%	0.96	11.62%
Weighted Average	10.72%	3.85%	0.94	11.13%
Sample 3: Small Non-Utilites				
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low	10.10%	3.39%	0.93	10.63%
High	11.63%	4.31%	1.00	11.62%
Weighted Average	11.29%	3.85%	1.02	11.13%

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Exhibit NAC-11: CAPM Estimates of the Cost of Equity Capital: Moderate-Sized Electric Utilities

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: MODERATE-SIZED ELECTRIC UTILITIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta	
Company	Ticker	2018-2023	2023	2018-2023	2023
ALLETE, Inc.	ALE	0.83	1.00	0.75	1.00
Alliant Energy Corporation	LNT	0.74	0.93	0.62	0.90
Black Hills	BCK	1.00	1.00	1.00	1.00
CenterPoint Energy, Inc.	CNP	1.16	1.13	1.25	1.20
Evergy, Inc.	EVRG	0.77	1.00	0.65	1.00
Hawaiian Electric Industries, Inc.	HE	0.68	1.00	0.53	1.00
IDACORP, Inc.	IDA	0.78	0.93	0.67	0.90
MGE Energy, Inc.	MGEE	0.74	0.87	0.62	0.80
Northwestern Energy Group	NEW	0.98	1.00	0.97	1.00
OGE Energy Corp.	OGE	0.92	1.07	0.88	1.10
Otter Tail Corporation	OTTR	0.82	1.00	0.73	1.00
Pinnacle West Capital Corporation	PNW	0.76	1.00	0.65	1.00
PNM Resources, Inc.	PNM	0.83	0.93	0.75	0.90
Portland General Electric Company	POR	0.76	0.93	0.64	0.90
Unitil Corporation	UTL	1.01	0.93	1.01	0.90
Average		0.85	0.98	0.78	0.97
Standard Deviation		0.13	0.06	0.20	0.10
Weighted Average:		0.87	1.01	0.81	1.01
CAPM ESTIMATES					
	Cost of Equity Capital,		Market Beta,	Expected	
	Unadjusted	Risk-Free Rate		Adjusted	Market Return
Low	10.39%	3.39%	0.97		10.63%
High	11.61%	4.31%	1.00		11.62%
Weighted Average	11.18%	3.85%	1.01		11.13%
U.S. Equity Market Risk Premia:					7.28%

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Exhibit NAC-12: CAPM Estimates of the Cost of Equity Capital: Gas Distribution Utilities

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: GAS DISTRIBUTION UTILITIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta	
Company	Ticker	2018-2023	2023	2018-2023	2023
Atmos Energy Corporation	ATO	0.74	0.93	0.62	0.90
Chesapeake Utilities Corporation	CPK	0.72	0.87	0.59	0.80
New Jersey Resources Corporation	NJR	0.85	1.00	0.78	1.00
Northwest Natural Holding Company	NWN	0.75	1.00	0.62	1.00
ONE Gas, Inc.	OGS	0.79	0.93	0.68	0.90
Southwest Gas Holdings, Inc.	SWX	0.75	0.93	0.62	0.90
Average		0.77	0.94	0.65	0.92
Standard Deviation		0.05	0.05	0.07	0.08
Weighted Average:		0.77	0.94	0.65	0.92
CAPM ESTIMATES					
	Cost of Equity Capital,		Market Beta,		Expected
	Unadjusted	Risk-Free Rate	Adjusted	Market Return	
Low	10.14%	3.39%	0.93	10.63%	
High	11.31%	4.31%	0.96	11.62%	
Weighted Average	10.72%	3.85%	0.94	11.13%	
U.S. Equity Market Risk Premia:					7.28%

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Exhibit NAC-13: CAPM Estimates of the Cost of Equity Capital: Moderate-Sized Utilities

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: MODERATE-SIZED UTILITIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta	
Company	Ticker	2018-2023	2023	2018-2023	2023
ALLETE, Inc.	ALE	0.83	1.00	0.75	1.00
Alliant Energy Corporation	LNT	0.74	0.93	0.62	0.90
Black Hills	BCK	1.00	1.00	1.00	1.00
CenterPoint Energy, Inc.	CNP	1.16	1.13	1.25	1.20
Evergy, Inc.	EVRG	0.77	1.00	0.65	1.00
Hawaiian Electric Industries, Inc.	HE	0.68	1.00	0.53	1.00
IDACORP, Inc.	IDA	0.78	0.93	0.67	0.90
MGE Energy, Inc.	MGEE	0.74	0.87	0.62	0.80
Northwestern Energy Group	NEW	0.98	1.00	0.97	1.00
OGE Energy Corp.	OGE	0.92	1.07	0.88	1.10
Otter Tail Corporation	OTTR	0.82	1.00	0.73	1.00
Pinnacle West Capital Corporation	PNW	0.76	1.00	0.65	1.00
PNM Resources, Inc.	PNM	0.83	0.93	0.75	0.90
Portland General Electric Company	POR	0.76	0.93	0.64	0.90
Unitil Corporation	UTL	1.01	0.93	1.01	0.90
Atmos Energy Corporation	ATO	0.74	0.93	0.62	0.90
Chesapeake Utilities Corporation	CPK	0.72	0.87	0.59	0.80
New Jersey Resources Corporation	NJR	0.85	1.00	0.78	1.00
Northwest Natural Holding Company	NWN	0.75	1.00	0.62	1.00
ONE Gas, Inc.	OGS	0.79	0.93	0.68	0.90
Southwest Gas Holdings, Inc.	SWX	0.75	0.93	0.62	0.90
Average		0.83	0.97	0.74	0.96
Standard Deviation		0.12	0.06	0.18	0.09
Weighted Average:		0.85	0.99	0.77	0.99
CAPM ESTIMATES					
		Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return
Low		10.31%	3.39%	0.96	10.63%
High		11.53%	4.31%	0.99	11.62%
Weighted Average		11.08%	3.85%	0.99	11.13%
U.S. Equity Market Risk Premia:					7.28%

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Exhibit NAC-14: CAPM Estimates of the Cost of Equity Capital: Small-Sized Non-Utility Companies

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: SMALL-SIZED NON-UTILITY COMPANIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta	
Company	Ticker	2018-2023	2023	2022-2023	2023
John Wiley & Sons, Inc.	WLY	0.93	0.93	0.90	0.90
Ingredion	INGR	0.90	0.87	0.86	0.81
Kinross Gold Corp	KGC	0.82	0.87	0.73	0.80
HNI Corporation	HNI	1.05	1.07	1.08	1.10
Kaman Corporation	KAMN	1.16	1.13	1.25	1.19
Smith & Wesson Brands, Inc.	SWBI	0.72	0.73	0.58	0.60
Entravision Communications Corporation	EVC	1.00	1.00	1.00	1.00
Luxfer Holdings PLC	LXFR	0.93	0.89	0.89	0.84
The Aaron's Company, Inc.	AAN	1.14	1.27	1.21	1.40
Natural Grocers by Vitamin Cottage, Inc.	NGVC	0.83	0.73	0.75	0.60
Adams Resources & Energy, Inc.	AE	1.02	1.13	1.04	1.20
LifeVantage Corporation	LFVN	0.98	0.93	0.98	0.90
Sonoco Products	SON	0.90	1.00	0.86	1.00
Sensient Technologies	SXT	0.93	0.93	0.90	0.90
Average		0.95	0.96	0.93	0.95
Standard Deviation		0.12	0.15	0.18	0.22
Weighted Average:		0.99	1.02	0.94	0.98
CAPM ESTIMATES					
		Cost of Equity Capital, Unadjusted		Market Beta, Adjusted	Expected Market Return
		Risk-Free Rate			
Low		10.10%	3.39%	0.93	10.63%
High		11.63%	4.31%	1.00	11.62%
Weighted Average		11.29%	3.85%	1.02	11.13%
U.S. Equity Market Risk Premia:					7.28%
		Cost Rate, Adjusted for Issuance Costs			
Low					
High					
Weighted Average					

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Exhibit NAC-15: Summary of Electric Utility Discounted Cash Flow Results

<u>2021</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.98%	5.15%	8.45%
High	3.66%	7.39%	10.73%
Weighted Average	3.36%	6.33%	9.69%
<u>2022</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	3.12%	5.39%	8.93%
High	3.94%	7.26%	10.79%
Weighted Average	3.42%	6.35%	9.77%
<u>2023</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	3.10%	5.28%	8.51%
High	3.93%	6.80%	10.60%
Weighted Average	3.53%	5.84%	9.37%

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Exhibit NAC-16: Discounted Cashflow Estimates of Cost of Equity: Moderate-Sized Electric Utilities, 2023

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2023							
Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, December '23	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
ALLETE, Inc.	ALE	2.71	2.82	63.22	4.46%	8.20%	12.66%
Alliant Energy Corporation	LNT	1.81	1.87	55.29	3.38%	6.29%	9.66%
Black Hills	BCK	2.50	2.60	65.37	3.97%	7.76%	11.73%
CenterPoint Energy, Inc.	CNP	0.77	0.79	30.68	2.56%	4.06%	6.62%
Evergy, Inc.	EVRG	2.48	2.57	62.47	4.11%	7.01%	11.12%
Hawaiian Electric Industries, Inc.	HE	1.08	1.11	39.10	2.84%	5.58%	8.41%
IDACORP, Inc.	IDA	3.20	3.26	111.67	2.92%	3.69%	6.61%
MGE Energy, Inc.	MGEE	1.67	1.71	77.14	2.22%	5.38%	7.60%
Northwestern Energy Group	NEW	2.56	2.64	58.94	4.47%	6.04%	10.51%
OGE Energy Corp.	OGE	1.66	1.73	37.43	4.63%	9.00%	13.63%
Otter Tail Corporation	OTTR	1.75	1.80	72.52	2.49%	6.11%	8.59%
Pinnacle West Capital Corporation	PNW	3.48	3.55	78.92	4.50%	4.10%	8.59%
PNM Resources, Inc.	PNM	1.57	1.61	48.03	3.35%	4.99%	8.34%
Portland General Electric Company	POR	1.88	1.94	50.41	3.85%	6.37%	10.21%
Unitil Corporation	UTL	1.62	1.67	55.89	2.99%	6.04%	9.02%

DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES			
	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	3.52%	6.04%	9.55%
S. D.	0.82%	1.52%	2.08%
Range			
Low	3.10%	5.28%	8.51%
High	3.93%	6.80%	10.60%
Weighted Average	3.53%	5.84%	9.37%
			Cost Rate, Adjusted for Issuance Costs
			Weighted Average 9.59%

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Exhibit NAC-17: Discounted Cashflow Estimates of Cost of Equity: Moderate-Sized Electric Utilities, 2022

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2022							
Electric Utility	Ticker	Dividend Per	Effective Year	Average Market	Adjusted	Expected	Single Stage DCF
		Share	Forward	Price Per Share,	Dividend		Estimates of Cost of
			Dividend	December '22	Yield	Growth	Equity Capital
ALLETE, Inc.	ALE	2.60	2.65	58.89	4.49%	3.51%	8.00%
Alliant Energy Corporation	LNT	1.71	1.77	57.85	3.06%	6.72%	9.77%
Black Hills	BCK	2.41	2.49	72.37	3.44%	6.33%	9.76%
CenterPoint Energy, Inc.	CNP	0.70	0.72	30.22	2.39%	6.33%	8.72%
Evergy, Inc.	EVRG	2.33	2.40	67.08	3.58%	5.91%	9.49%
Hawaiian Electric Industries, Inc.	HE	1.40	1.44	40.65	3.55%	6.33%	9.88%
IDACORP, Inc.	IDA	3.04	3.16	102.39	3.08%	7.57%	10.65%
MGE Energy, Inc.	MGEE	1.59	1.63	76.77	2.12%	4.49%	6.61%
Northwestern Energy Group	NEW	2.52	2.59	55.66	4.65%	5.57%	10.22%
OGE Energy Corp.	OGE	1.64	1.70	38.48	4.42%	7.35%	11.77%
Otter Tail Corporation	OTTR	1.65	1.70	58.86	2.89%	6.33%	9.22%
Pinnacle West Capital Corporation	PNW	3.42	3.50	71.24	4.91%	4.67%	9.58%
PNM Resources, Inc.	PNM	1.41	1.49	46.06	3.24%	11.88%	15.13%
Portland General Electric Company	POR	1.79	1.84	46.64	3.95%	5.61%	9.56%
Unitil Corporation	UTL	1.56	1.61	50.17	3.21%	6.33%	9.54%
DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES							
					Adjusted	Expected	Unadjusted Cost Rate
					Dividend		
					Yield	Growth	
Average					3.53%	6.33%	9.86%
S. D.					0.82%	1.87%	1.86%
Range							
Low					3.12%	5.39%	8.93%
High					3.94%	7.26%	10.79%
Weighted Average					3.42%	6.35%	9.77%
Cost Rate, Adjusted for							Issuance Costs
Weighted Average							
							9.99%

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Exhibit NAC-18: Discounted Cashflow Estimates of Cost of Equity: Moderate-Sized Electric Utilities, 2021

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2021							
Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, December '21	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
ALLETE, Inc.	ALE	2.52	2.56	70.69	3.63%	3.48%	7.11%
Alliant Energy Corporation	LNT	1.61	1.66	56.17	2.96%	6.67%	9.63%
Black Hills	BCK	2.29	2.36	68.99	3.42%	6.27%	9.70%
CenterPoint Energy, Inc.	CNP	0.66	0.68	24.42	2.79%	6.27%	9.06%
Evergy, Inc.	EVRG	2.18	2.24	64.06	3.50%	5.84%	9.34%
Hawaiian Electric Industries, Inc.	HE	1.36	1.40	43.20	3.25%	6.27%	9.52%
IDA CORP, Inc.	IDA	2.88	3.00	102.14	2.94%	8.38%	11.32%
MGE Energy, Inc.	MGEE	1.52	1.55	75.22	2.07%	4.38%	6.45%
Northwestern Energy Group	NEW	2.48	2.52	67.82	3.72%	3.32%	7.04%
OGE Energy Corp.	OGE	1.63	1.69	33.49	5.06%	7.95%	13.01%
Otter Tail Corporation	OTTR	1.56	1.61	47.89	3.36%	6.27%	9.63%
Pinnacle West Capital Corporation	PNW	3.36	3.45	84.53	4.08%	5.09%	9.16%
PNM Resources, Inc.	PNM	1.33	1.41	49.54	2.85%	12.55%	15.40%
Portland General Electric Company	POR	1.70	1.74	50.48	3.45%	5.06%	8.51%
Unitil Corporation	UTL	1.52	1.57	57.59	2.72%	6.27%	8.99%

DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES			
	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	3.32%	6.27%	9.59%
S. D.	0.69%	2.23%	2.28%
Range			
Low	2.98%	5.15%	8.45%
High	3.66%	7.39%	10.73%
Weighted Average	3.36%	6.33%	9.69%
			Cost Rate, Adjusted for Issuance Costs
			Weighted Average 9.90%

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Exhibit NAC-19: Summary of Gas Utility Discounted Cash Flow Results

<u>2021</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.40%	7.64%	10.29%
High	3.13%	10.86%	13.75%
Weighted Average	2.78%	9.30%	12.08%
<u>2022</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.42%	7.63%	10.27%
High	3.09%	10.45%	13.32%
Weighted Average	2.77%	9.19%	11.96%
<u>2023</u>			
	Dividend Yield	Expected Growth in Cash Flows	Unadjusted Cost Rate
Low	2.76%	4.95%	8.40%
High	3.71%	6.78%	9.81%
Weighted Average	3.00%	6.45%	9.45%

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Exhibit NAC-20: Discounted Cashflow Estimates of Cost of Equity: Gas Distribution Utilities, 2023

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2023							
Gas Utility	Ticker	Dividend Per Share	Effective Year	Average Market Price Per Share,	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
			Forward Dividend				
Atmos Energy Corporation	ATO	2.96	3.07	114.55	2.68%	7.64%	10.32%
Chesapeake Utilities Corporation	CPK	2.31	2.39	123.50	1.94%	7.30%	9.24%
New Jersey Resources Corporation	NJR	1.59	1.65	51.67	3.18%	7.00%	10.18%
Northwest Natural Holding Company	NWN	1.94	2.00	46.85	4.27%	6.00%	10.27%
ONE Gas, Inc.	OGS	2.60	2.64	77.29	3.42%	3.25%	6.67%
Southwest Gas Holdings, Inc.	SWX	2.48	2.53	56.46	4.48%	4.00%	8.48%

DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES			
	Adjusted		Unadjusted Cost
	Dividend Yield	Expected Growth	
Average	3.33%	5.86%	9.19%
S. D.	0.96%	1.83%	1.43%
Range			
Low	3.81%	4.95%	8.8%
High	2.85%	6.78%	9.6%
Weighted Average	3.09%	6.45%	9.55%
			Cost Rate, Adjusted for Issuance Costs
	Weighted Average		9.74%

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Exhibit NAC-21: Discounted Cashflow Estimates of Cost of Equity: Gas Distribution Utilities, 2022

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2022							
Gas Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, December '22	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Atmos Energy Corporation	ATO	2.72	2.85	111.76	2.55%	9.35%	11.9%
Chesapeake Utilities Corporation	CPK	1.84	1.91	122.00	1.56%	7.47%	9.0%
New Jersey Resources Corporation	NJR	1.45	1.50	42.79	3.50%	6.76%	10.3%
Northwest Natural Holding Company	NWN	1.93	2.02	47.29	2.76%	9.04%	11.8%
ONE Gas, Inc.	OGS	2.48	2.66	82.63	3.22%	14.39%	17.6%
Southwest Gas Holdings, Inc.	SWX	2.48	2.57	87.13	2.95%	7.22%	10.2%

DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES			
	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	2.76%	9.04%	11.79%
S. D.	0.67%	2.82%	3.04%
Range			
Low	2.42%	7.63%	10.27%
High	3.09%	10.45%	13.32%
Weighted Average	2.77%	9.19%	11.96%
			Cost Rate, Adjusted for Issuance Costs
	Weighted Average		12.14%

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Exhibit NAC-22: Discounted Cashflow Estimates of Cost of Equity: Gas Distribution Utilities, 2021

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2021							
Gas Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, December '21	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Atmos Energy Corporation	ATO	2.50	2.61	103.79	2.52%	9.11%	11.63%
Chesapeake Utilities Corporation	CPK	1.69	1.75	120.89	1.45%	7.12%	8.57%
New Jersey Resources Corporation	NJR	1.36	1.40	43.13	3.26%	6.61%	9.86%
Northwest Natural Holding Company	NWN	1.92	2.01	54.40	2.76%	9.25%	12.02%
ONE Gas, Inc.	OGS	2.32	2.50	80.58	3.10%	15.46%	18.57%
Southwest Gas Holdings, Inc.	SWX	2.38	2.47	70.91	3.49%	7.96%	11.45%
DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES							
				Adjusted Dividend Yield		Expected Growth	Unadjusted Cost Rate
Average				2.76%		9.25%	12.02%
S. D.				0.73%		3.22%	3.46%
Range							
Low				2.40%		7.64%	10.29%
High				3.13%		10.86%	13.75%
Weighted Average				2.78%		9.30%	12.08%
						Cost Rate, Adjusted for Issuance Costs	
						Weighted Average	
						12.26%	

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Exhibit NAC-23: Risk Premia and Equity Returns

	Equity Returns		Real Returns on US Treasury Debt		
	<u>L-Cap</u>	<u>S-Cap</u>	<u>LT US Debt</u>	<u>InT US Debt</u>	<u>T-Bills</u>
2014	11.39%	1.66%	24.62%	3.77%	0.02%
2015	-0.73%	-12.02%	-0.67%	1.89%	0.02%
2016	9.54%	22.04%	1.38%	1.29%	0.20%
2017	19.42%	16.96%	6.36%	1.25%	0.79%
2018	-6.24%	-17.04%	-0.54%	1.53%	1.80%
2019	28.88%	19.52%	12.09%	6.29%	2.14%
2020	16.26%	0.18%	15.19%	7.38%	0.45%
2021	26.89%	34.98%	-5.08%	-2.53%	0.04%
2022	-19.44%	-5.67%	-26.73%	-9.72%	1.43%
2023	24.23%	5.36%	3.16%	4.59%	4.97%
Average	11.02%	6.60%	2.98%	1.57%	1.19%
Overall Financial Markets			Utility Sector Return Requirements		
			Electricity	Natural Gas	Low-Risk Non-Utilities
Approximate Baseline Real Return, Risk Free	1.53%		1.53%	1.53%	1.53%
Expected Inflation	2.46%		3.98%	3.98%	3.98%
Differential Cost of Capital for Asset Classes					
Intermediate Term U.S. Treasury Securities	0.05%		4.03%	4.03%	4.03%
Long-Term U.S. Treasury Securities	1.40%		5.43%	5.43%	5.43%
Risk Premia for Equity Market Asset Class	5.83%				
Total Return, Equity Capital	11.27%		<u>10.52%</u>	<u>9.90%</u>	<u>11.39%</u>

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Exhibit NAC-24: Market Returns: Year Ending 10-Year Averages

<u>Market Returns: Year Ending 10-Year Averages</u>				
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
<u>Moderate Sized Electric Utilities</u>				
Average Across the Sample	11.57%	12.22%	11.52%	9.65%
2013-2023 Average Unadjusted				11.52%
<u>Natural Gas Utilities</u>				
Average Across the Sample	13.71%	12.81%	12.88%	8.95%
2013-2023 Average Unadjusted				13.21%
<u>Small Non-Utility Companies (5-year avg)</u>				
Average Across the Sample	11.70%	18.49%	-21.60%	17.43%
2013-2023 Average Unadjusted				9.89%

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Exhibit NAC-25: Average Realized Historical Returns, Price Inflation (%)

AVERAGE REALIZED HISTORICAL RETURNS, PRICE INFLATION (%)								
	U.S. Treasury Debt				Equity Markets			Inflation
	Bills	In-T Debt	L-T Debt	Corporate Debt	US			
					Large Cap	Markets	Small Cap	
1920s	3.6750	4.2075	5.0550	5.2300	16.2877	16.7025	14.3109	-3.7000
1930s	0.5560	4.6420	5.0350	7.0370	0.0412	5.3050	23.0563	-1.9300
1940s	0.4100	1.8086	3.2988	2.7190	4.0982	10.6430	33.8058	3.8591
1950s	1.8690	1.4473	0.1557	4.2620	14.9661	19.6620	23.2687	2.2418
1960s	3.8870	3.6191	1.4578	1.8070	5.2569	9.2800	22.2346	2.5273
1970s	6.3240	7.0692	5.6675	7.1590	3.2001	7.9250	17.7967	7.4366
1980s	8.9210	12.0067	13.7249	13.8280	13.2109	17.3570	18.7589	5.1284
1990s	4.9330	7.5042	9.2285	8.8350	16.1305	18.8660	14.7386	2.9501
2000s	2.7730	6.3323	8.3127	7.7350	-0.6056	1.9320	22.1626	2.5661
2010s	0.5218	3.1055	7.1648	9.0766	11.8046	14.3320	10.1922	1.7561
1947-2023	3.3014	5.0193	5.5838	6.5388	8.1033	11.4547	19.9208	3.5463
1970-2023	4.4483	6.4458	7.7054	8.3333	8.9966	12.1753	16.7809	4.0004
1990-2023	2.3305	4.4043	6.4810	6.9583	9.5814	11.6967	15.1583	2.5294
Expected Inflation								2.46
Sample Period Long-Term Risk Free Rate								
2013-2023					4.31			
2021-2023					3.39			
Sample Period Market Returns (%)								
	Nominal		Inflation		Real			
1947-2023	11.4547		3.5463		7.91			
1970-2023	12.18		4.00		8.17			
1990-2023	11.70		2.53		9.17			
Expected Future Market Returns (%)								
	Real Return		Inflation		Nominal			
1970-2023	8.17		2.46		10.63			
1990-2023	9.17		2.46		11.62			

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Exhibit NAC-26: Capitalization Weights for Small to Mid-Sized Electricity Distributors

Small to Mid-Sized Electricity Distributors					
Company Name	Ticker	Market Price	Shares Outstanding (000s)	Market Capitalization (\$ 000s)	Capitalization Weights
ALLETE, Inc.	ALE	63.22	57,300	3,622,506	4%
Alliant Energy Corporation	LNT	55.29	253,000	13,988,370	14%
Black Hills	BKH	65.37	67,000	4,379,790	4%
CenterPoint Energy, Inc.	CNP	30.68	631,000	19,359,080	19%
Evergy, Inc.	EVRG	62.47	230,000	14,368,100	14%
Hawaiian Electric Industries, Inc.	HE	39.10	109,700	4,289,270	4%
IDACORP, Inc.	IDA	111.67	50,700	5,661,669	6%
MGE Energy, Inc.	MGEE	77.14	36,163	2,789,614	3%
Northwestern Energy Group	NWE	58.94	60,321	3,555,348	4%
OGE Energy Corp.	OGE	37.43	200,300	7,497,229	7%
Otter Tail Corporation	OTTR	72.52	41,668	3,021,763	3%
Pinnacle West Capital Corporation	PNW	78.92	113,400	8,949,528	9%
PNM Resources, Inc.	PNM	48.03	86,296	4,144,797	4%
Portland General Electric Company	POR	50.41	97,760	4,928,082	5%
Unitil Corporation	UTL	55.89	16,045	896,755	1%

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Exhibit NAC-27: Capitalization Weights for Small to Mid-Sized Natural Gas Distributors

Small to Mid-Sized Natural Gas Distributors					
Company Name	Ticker	Market Price	Shares Outstanding (000s)	Market Capitalization (\$ 000s)	Capitalization Weights
Atmos Energy Corporation	ATO	101.99	145,100	14,798,749	43%
Chesapeake Utilities Corporation	CPK	91.97	18,370	1,689,489	5%
New Jersey Resources Corporatic	NJR	49.56	97,028	4,808,708	14%
Northwest Natural Holding Comp	NWN	66.60	36,213	2,411,786	7%
ONE Gas, Inc.	OGS	87.57	55,600	4,868,892	14%
Southwest Gas Holdings, Inc.	SWX	82.36	70,787	5,830,017	17%

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Exhibit NAC-28: Capitalization Weights for Small to Mid-Sized Distribution Utilities

Small to Mid-Sized Distribution Utilities					
Company Name	Ticker	Market Price	Shares Outstanding (000s)	Market Capitalization (\$ 000s)	Capitalization Weights
ALLETE, Inc.	ALE	63.22	57,300	3,622,506	2.8%
Alliant Energy Corporation	LNT	55.29	253,000	13,988,370	10.7%
Black Hills	BKH	65.37	67,000	4,379,790	3.3%
CenterPoint Energy, Inc.	CNP	30.68	631,000	19,359,080	14.8%
Evergy, Inc.	EVRG	62.47	230,000	14,368,100	11.0%
Hawaiian Electric Industries, Inc.	HE	39.10	109,700	4,289,270	3.3%
IDA CORP, Inc.	IDA	111.67	50,700	5,661,669	4.3%
MGE Energy, Inc.	MGEE	77.14	36,163	2,789,614	2.1%
Northwestern Energy Group	NWE	58.94	60,321	3,555,348	2.7%
OGE Energy Corp.	OGE	37.43	200,300	7,497,229	5.7%
Otter Tail Corporation	OTTR	72.52	41,668	3,021,763	2.3%
Pinnacle West Capital Corporation	PNW	78.92	113,400	8,949,528	6.8%
PNM Resources, Inc.	PNM	48.03	86,296	4,144,797	3.2%
Portland General Electric Company	POR	50.41	97,760	4,928,082	3.8%
Unitil Corporation	UTL	55.89	16,045	896,755	0.7%
Atmos Energy Corporation	ATO	101.99	119,339	12,171,385	9.3%
Chesapeake Utilities Corporation	CPK	91.97	16,404	1,508,676	1.2%
New Jersey Resources Corporation	NJR	49.56	89,999	4,460,351	3.4%
Northwest Natural Holding Company	NWN	66.60	30,472	2,029,435	1.6%
ONE Gas, Inc.	OGS	87.57	52,772	4,621,244	3.5%
Southwest Gas Holdings, Inc.	SWX	82.36	55,007	4,530,377	3.5%

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Exhibit NAC-29: Market Returns: Moderate Sized Electric Utilities Year Ending 10-Year Averages

<u>Market Returns: Moderate Sized Electric Utilities Year Ending 10-Year Averages</u>				
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
ALLETE, Inc.	9.02%	10.89%	9.04%	7.48%
Alliant Energy Corporation	14.57%	14.87%	13.54%	11.37%
CenterPoint Energy, Inc.	8.36%	10.30%	11.54%	9.62%
Black Hills	9.74%	11.54%	12.81%	8.32%
Evergy, Inc.	13.40%	13.35%	13.09%	10.38%
Hawaiian Electric Industries, Inc.	9.84%	10.18%	9.02%	8.07%
IDACORP, Inc.	12.81%	13.75%	13.35%	12.40%
MGE Energy, Inc.	13.10%	13.88%	12.96%	11.05%
OGE Energy Corp.	8.93%	7.50%	9.00%	5.69%
Otter Tail Corporation	12.06%	12.81%	15.43%	13.68%
Pinnacle West Capital Corporation	11.96%	11.78%	9.13%	7.68%
PNM Resources, Inc.	14.70%	16.35%	13.28%	11.23%
Portland General Electric Company	12.59%	11.55%	10.38%	8.74%
Unitil Corporation	12.74%	13.17%	11.02%	10.55%
Northwestern Energy Group	9.74%	11.44%	9.23%	8.46%
Average Across the Sample	11.57%	12.22%	11.52%	9.65%
	2020-2023 Average Unadjusted			11.24%

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Exhibit NAC-30: Historical Market Returns for Moderate-Sized Electric Utilities, Average per Annum

HISTORICAL MARKET RETURNS FOR MODERATE-SIZED ELECTRIC UTILITIES, AVERAGE PER ANNUM								
Company	2014-16	2015-17	2016-18	2017-19	2018-2020	2019-2021	2020-2022	2021-2023
ALLETE, Inc.	8.3%	14.8%	19.0%	15.7%	-1.9%	4.1%	-3.1%	10.2%
Alliant Energy Corporation	14.6%	13.8%	15.6%	12.9%	9.9%	13.0%	10.9%	9.0%
CenterPoint Energy, Inc.	0.9%	10.8%	12.4%	18.2%	-8.3%	11.3%	11.6%	27.7%
Black Hills	14.7%	9.6%	9.3%	10.6%	1.2%	11.9%	4.5%	7.2%
Evergy, Inc.	19.3%	18.1%	17.3%	7.1%	5.9%	9.7%	9.2%	7.9%
Hawaiian Electric Industries, Inc.	12.1%	17.6%	7.2%	11.8%	8.4%	11.7%	3.3%	4.4%
IDACORP, Inc.	19.2%	17.7%	19.0%	13.4%	5.0%	6.7%	4.7%	11.4%
MGE Energy, Inc.	15.6%	21.9%	16.0%	12.9%	1.8%	11.5%	7.4%	9.9%
OGE Energy Corp.	-2.5%	2.0%	4.9%	16.9%	2.3%	7.9%	4.0%	12.4%
Otter Tail Corporation	3.0%	15.6%	18.8%	24.1%	7.1%	7.2%	9.8%	22.6%
Pinnacle West Capital Corporation	11.3%	18.7%	14.1%	12.7%	0.7%	7.4%	-3.6%	7.5%
PNM Resources, Inc.	14.7%	13.4%	15.4%	15.5%	5.6%	12.8%	4.7%	11.2%
Portland General Electric Company	11.8%	14.1%	10.1%	12.8%	4.2%	10.7%	0.5%	8.3%
Unitil Corporation	13.9%	17.2%	16.5%	16.4%	4.1%	9.9%	0.0%	8.5%
Northwestern Energy Group	15.1%	11.6%	6.2%	11.0%	3.2%	13.1%	-1.4%	7.2%
Average	11.5%	14.5%	13.4%	14.1%	3.3%	9.9%	4.2%	11.0%
Weighted Average	12.9%	14.1%	14.0%	13.3%	4.2%	10.5%	5.9%	10.5%

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Exhibit NAC-31: Market Returns: Natural Gas Utilities Year Ending 10-Year Averages

<u>Market Returns: Natural Gas Utilities Year Ending 10-Year Averages</u>				
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
AltaGas Ltd.	16.59%	15.15%	16.39%	13.19%
Chesapeake Utilities Corporation	19.11%	18.99%	19.04%	16.37%
New Jersey Resources Corporation	10.48%	11.86%	11.82%	13.42%
Northwest Natural Holding Company	6.34%	5.55%	4.28%	4.70%
Southwest Gas Holdings, Inc.	12.36%	9.67%	11.34%	6.04%
ONE Gas, Inc.	17.37%	15.66%	14.40%	0.00%
Average Across the Sample	13.71%	12.81%	12.88%	8.95%
	2019-2023 Average Unadjusted			12.09%

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Exhibit NAC-32: Historical Market Returns for Gas Distribution Utilities, Average per Annum

HISTORICAL MARKET RETURNS FOR GAS DISTRIBUTION UTILITIES, AVERAGE PER ANNUM								
Company	2014-16	2015-17	2016-18	2017-19	2018-2020	2019-2021	2020-2022	2021-2023
Atmos Energy Corporation	22.2%	19.6%	20.0%	14.4%	10.1%	8.9%	5.6%	7.2%
Chesapeake Utilities Corporation	22.9%	23.3%	19.3%	17.3%	8.3%	20.4%	13.3%	15.7%
New Jersey Resources Corporation	20.5%	21.1%	14.2%	14.1%	-0.5%	8.4%	1.9%	20.1%
Northwest Natural Holding Company	10.7%	14.3%	13.2%	11.5%	4.5%	-0.6%	-7.6%	-5.3%
Southwest Gas Holdings, Inc.	13.2%	18.8%	14.1%	11.7%	-0.6%	2.6%	6.0%	-2.3%
ONE Gas, Inc.	31.1%	26.8%	23.4%	16.6%	7.9%	6.9%	1.1%	2.6%
Average	20.1%	20.6%	17.4%	14.3%	5.0%	7.7%	3.4%	6.3%
Weighted Average	21.2%	20.6%	18.2%	14.2%	6.0%	7.4%	3.9%	6.5%

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Exhibit NAC-33: Market Returns: Small Non-Utilities Year Ending 5-Year Averages

<u>Market Returns: Small Non-Utilities Year Ending 5-Year Averages</u>				
	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
John Wiley & Sons, Inc.	-3.47%	28.41%	-27.66%	-17.32%
Ingredion	-12.66%	26.06%	3.99%	13.54%
Kinross Gold Corp	54.85%	-20.03%	-27.54%	50.86%
HNI Corporation	-4.78%	25.57%	-29.44%	51.60%
Kaman Corporation	-12.12%	-23.07%	-46.47%	10.99%
Smith & Wesson Brands, Inc.	148.95%	0.28%	-50.39%	59.91%
Entravision Communications Corporation	12.60%	151.27%	-27.73%	-11.04%
Luxfer Holdings PLC	-8.59%	20.65%	-26.36%	-31.20%
Natural Grocers by Vitamin Cottage, Inc.	39.21%	5.75%	-33.89%	79.43%
Adams Resources & Energy, Inc.	-34.23%	19.38%	43.40%	-30.27%
LifeVantage Corporation	-40.29%	-32.19%	-41.14%	62.10%
Sonoco Products	-1.25%	0.61%	7.98%	-4.81%
Sensient Technologies	13.84%	37.75%	-25.54%	-7.24%
Average Across the Sample	11.70%	18.49%	-21.60%	17.43%
	2020-2023 Average Unadjusted			6.50%

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Exhibit NAC-34: Historical Market Returns for Small, Non-Utility Companies, Average per Annum

Non-Utility Companies	2020	2021	2022	2023	2020-2022	2020-2023	Market Cap	Proportion
					Avg	Avg		
John Wiley & Sons, Inc.	-3.47%	28.41%	-27.66%	-17.32%	-5.53%	-3%	1,763,411	6%
Ingredion	-12.66%	26.06%	3.99%	13.54%	14.53%	7%	7,162,980	25%
Kinross Gold Corp	54.85%	-20.03%	-27.54%	50.86%	1.10%	21%	7,405,200	26%
HNI Corporation	-4.78%	25.57%	-29.44%	51.60%	15.91%	10%	1,861,435	6%
Kaman Corporation	-12.12%	-23.07%	-46.47%	10.99%	-19.52%	-10%	678,264	2%
Smith & Wesson Brands, Inc.	148.95%	0.28%	-50.39%	59.91%	3.27%	26%	621,645	2%
Entravision Communications Corporation	12.60%	151.27%	-27.73%	-11.04%	37.50%	24%	366,547	1%
Luxfer Holdings PLC	-8.59%	20.65%	-26.36%	-31.20%	-12.30%	-8%	239,860	1%
Natural Grocers by Vitamin Cottage, Inc.	39.21%	5.75%	-33.89%	79.43%	17.10%	11%	363,920	1%
Adams Resources & Energy, Inc.	-34.23%	19.38%	43.40%	-30.27%	10.84%	0%	66,680	0%
LifeVantage Corporation	-40.29%	-32.19%	-41.14%	62.10%	-3.74%	-7%	75,342	0%
Sonoco Products	-1.25%	0.61%	7.98%	-4.81%	1.26%	4%	5,491,686	19%
Sensient Technologies	13.84%	37.75%	-25.54%	-7.24%	1.66%	8%	2,773,782	10%
							28,870,752	100%
							2020-2022	2020-
							Wtd Avg	2023
								Wtd Avg
							5.19%	9.89%

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Exhibit NAC-35: Long-Term Debt Cost Rate, Test Year 2025

LONG-TERM DEBT COST RATE, TEST YEAR 2025										
Coupon Rate	Issue Date	Maturity Date	Life	Initial Principal Amount	13-Month Average Amount Outstanding	Unamortized Issuance Expenses	Annual Amortization of Issuance Expenses	Interest Expense	AI-In Annual Carrying Charges on Long-Term	Average Unamortized Issuing Expenses and Loss on Required Debt
5.68%	6/24/2011	6/30/2026	15	\$29,000,000	\$4,238,462	\$34,794	\$473	\$247,080	\$247,553	\$339
6.43%	5/2/2013	5/2/2028	15	\$7,000,000	\$2,369,231	\$12,789	\$409	\$150,158	\$150,567	\$683
3.73%	12/16/2013	12/16/2028	15	\$20,000,000	\$7,846,154	\$68,794	\$2,587	\$295,292	\$297,879	\$5,067
3.88%	5/15/2014	5/15/2029	15	\$50,000,000	\$21,923,077	\$192,790	\$8,020	\$848,211	\$856,231	\$17,392
3.25%	4/21/2017	4/30/2032	15	\$70,000,000	\$48,461,538	\$150,539	\$10,346	\$1,583,021	\$1,593,367	\$36,062
3.48%	5/21/2018	5/31/2038	20	\$50,000,000	\$50,000,000	\$99,400	\$6,413	\$1,740,000	\$1,746,413	\$53,976
3.58%	11/15/2018	11/30/2038	20	\$50,000,000	\$50,000,000	\$95,036	\$6,083	\$1,790,000	\$1,796,083	\$54,990
3.98%	8/13/2019	8/20/2039	20	\$100,000,000	\$100,000,000	\$167,966	\$10,836	\$3,980,000	\$3,990,836	\$104,753
2.98%	12/20/2019	12/20/2034	15	\$70,000,000	\$69,461,538	\$165,643	\$15,776	\$2,079,626	\$2,095,402	\$78,878
3.00%	7/15/2020	7/15/2035	15	\$50,000,000	\$50,000,000	\$92,476	\$8,807	\$1,500,000	\$1,508,807	\$49,174
2.96%	8/15/2020	8/15/2035	15	\$40,000,000	\$40,000,000	\$72,953	\$6,948	\$1,184,000	\$1,190,948	\$39,371
2.49%	12/20/2021	1/25/2037	15	\$50,000,000	\$50,000,000	\$161,664	\$15,275	\$1,245,000	\$1,260,275	\$108,200
2.95%	3/15/2022	3/15/2042	20	\$50,000,000	\$50,000,000	\$98,738	\$4,937	\$1,475,000	\$1,479,937	\$82,693
5.43%	3/14/2023	3/14/2038	15	\$80,000,000	\$80,000,000	\$117,035	\$11,146	\$4,344,000	\$4,355,146	\$91,957
6.39%	11/28/2023	12/28/2026	3	\$21,411,000	\$21,411,000	\$126,030	\$40,912	\$1,368,163	\$1,409,075	\$61,368
6.44%	11/28/2023	12/28/2027	4	\$21,411,000	\$21,411,000	\$114,789	\$28,133	\$1,378,868	\$1,407,001	\$70,332
6.45%	11/28/2023	12/28/2028	5	\$21,411,000	\$21,411,000	\$122,551	\$24,122	\$1,381,010	\$1,405,132	\$84,427
6.62%	11/28/2023	12/28/2030	7	\$21,411,000	\$21,411,000	\$121,213	\$17,119	\$1,417,408	\$1,434,528	\$94,157
6.71%	11/28/2023	12/28/2033	10	\$21,411,000	\$21,411,000	\$97,179	\$9,641	\$1,436,678	\$1,446,319	\$81,949
6.73%	11/28/2023	12/28/2038	15	\$10,705,500	\$10,705,500	\$46,743	\$3,091	\$720,480	\$723,571	\$41,730
5.75%	1/1/2025	1/1/2035	10	\$150,000,000	\$138,461,538	\$675,000	\$67,500	\$8,625,000	\$8,692,500	\$589,327
5.75%	10/1/2025	10/1/2035	10	\$100,000,000	\$23,076,923	\$450,000	\$11,250	\$1,437,500	\$1,448,750	\$102,115
Total				\$1,083,760,500	\$903,598,961	\$3,284,121	\$309,824	\$40,226,495	\$40,536,320	\$1,848,939
Loss on Reacquired Debt							\$73,704		\$73,704	\$463,397
Adjustment for Outstanding L-T Debt Shelf Agreements							\$20,940		\$20,940	\$49,312
Outstanding Principal					\$903,598,961	\$3,284,121	\$404,468	\$40,226,495	\$40,630,964	\$2,361,648
Loss on Issuance, Reacquired Debt					\$2,361,648					
Net Outstanding Principal					\$901,237,313	Embedded Cost of Long-Term Debt	\$40,630,964	Long-Term Debt Cost Rate	4.51%	

Nicholas A. Crowley, Witness
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August 22, 2024
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Exhibit NAC-36: Short-Term Debt Cost Rate, Test Year 2025

SHORT-TERM DEBT COST RATE, TEST YEAR 2025														
13-Month Weighted Average														
Item	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTALS/ AVERAGES
<u>OUTSTANDING BALANCE</u>														
Balance at														
End of Month	\$299,235,077	\$160,801,058	\$156,149,753	\$137,613,265	\$138,403,715	\$147,316,603	\$190,493,695	\$203,477,742	\$192,195,976	\$214,362,391	\$128,592,954	\$120,235,375	\$123,443,008	\$170,178,509
Average Monthly														
Balance		\$230,018,067	\$158,475,405	\$146,881,509	\$138,008,490	\$142,860,159	\$168,905,149	\$196,985,719	\$197,836,859	\$203,279,184	\$171,477,673	\$124,414,165	\$121,839,192	\$166,748,464
<u>UNAMORTIZED S-T DEBT EXPENSES</u>														
Balance at														
End of Month	\$488,788	\$461,026	\$433,263	\$405,500	\$377,738	\$349,975	\$322,212	\$294,450	\$266,687	\$238,924	\$211,162	\$183,399	\$155,636	\$322,212
Average Monthly														
Balance		\$474,907	\$447,144	\$419,382	\$391,619	\$363,856	\$336,094	\$308,331	\$280,568	\$252,806	\$225,043	\$197,280	\$169,518	\$322,212
<u>NET AVERAGE</u>														
<u>MONTHLY BALANCE</u>		\$229,543,160	\$158,028,261	\$146,462,127	\$137,616,871	\$142,496,302	\$168,569,055	\$196,677,388	\$197,556,291	\$203,026,378	\$171,252,630	\$124,216,885	\$121,669,674	\$166,426,252
<u>S-T DEBT SERVICE COSTS</u>														
Interest on S-T Debt		\$820,847	\$719,866	\$701,044	\$675,068	\$742,797	\$931,177	\$1,014,911	\$958,565	\$1,069,002	\$665,135	\$604,035	\$639,858	\$9,542,305
Amortization of S-T Debt		\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$27,763	\$333,152
Total Monthly														
S-T Debt Costs		\$848,610	\$747,628	\$728,806	\$702,831	\$770,560	\$958,940	\$1,042,674	\$986,328	\$1,096,764	\$692,898	\$631,797	\$667,620	\$9,875,457
SHORT-TERM DEBT COST RATE														5.81%
EFFECTIVE SHORT-TERM DEBT COST RATE:														5.93%

Docket No. 20240099-EI
Florida Public Utilities

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing filing has been served by Electronic Mail this 22nd day of August, 2024, upon the following:

Walter Trierweiler, Public Counsel
Office of the Public Counsel
c/o The Florida Legislature
111 West Madison St., Rm 812
Tallahassee, FL 32399-1400
Trierweiler. walt@leg.state.fl.us

By: _____



Beth Keating g
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida
Public Utilities Company.

DOCKET NO. 20240099-EI
ORDER NO. PSC-2025-0287-AS-EI
ISSUED: July 24, 2025

The following Commissioners participated in the disposition of this matter:

MIKE LA ROSA, Chairman
ART GRAHAM
GARY F. CLARK
ANDREW GILES FAY
GABRIELLA PASSIDOMO SMITH

FINAL ORDER APPROVING SETTLEMENT AGREEMENT

BY THE COMMISSION:

APPEARANCES:

BETH KEATING, ESQUIRE, Gunster Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301; appearing on behalf of Florida Public Utilities Company (FPUC).

WALT TRIERWEILER, PUBLIC COUNSEL; PATRICIA CHRISTENSEN, ESQUIRE, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 west Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

ROBERT SCHEFFEL WRIGHT and JOHN T. LaVIA, III, Gardner Law Firm, 1300 Thomaswood Drive, Tallahassee, Florida, appearing on behalf of the City of Marianna, Jackson County Board of County Commissioners, and the Jackson County School Board.

SUZANNE BROWNLESS, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

SAMANTHA CIBULA, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

BY THE COMMISSION:

BACKGROUND

Florida Public Utilities Company (FPUC or Company) filed a test year notification letter with the Florida Public Service Commission (Commission) on June 18, 2024, in which the

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Company indicated its intent to seek a permanent increase in its rates and charges based on a test year ending December 31, 2025, and a request for an interim rate increase. On August 22, 2024, FPUC filed its petition for an increase in base rates, as well as minimum filing requirements schedules (MFRs) and direct testimony of 10 witnesses. At that time FPUC requested that its petition for rate increase be processed using the proposed agency action process in Section 366.06(4), F.S.

Order No. PSC-2024-0441-PCO-EI, issued October 14, 2024, suspended the final rates and approved interim rates.¹ On September 5, 2024, the Office of Public Counsel (OPC) filed its Notice of Intervention which was acknowledged by Order No. PSC-2024-0408-PCO-EI, issued on September 5, 2024. Order No. PSC-2025-0114-PAA-EI,² granting in part and denying in part FPUC's rate increase, was issued on April 7, 2025. A timely request for hearing on Order No. PSC-2025-0114-PAA-EI was filed by the City of Marianna, Jackson County, and the Jackson County School Board (Jackson County) on April 21, 2025. OPC filed its request for hearing on April 24, 2025. On May 7, 2025, FPUC, OPC and Jackson County filed a Joint Motion for Approval of Stipulation and Settlement, a unanimous settlement which resolves all of the issues in this case (2025 Settlement), which is incorporated and attached as Attachment A. On June 5, 2025, Order No. PSC-2025-0189-PCO-EI was issued establishing procedure and setting the key elements of the 2025 Settlement to be addressed by the parties at the final hearing.

A final hearing was held on July 1, 2025, in which the prefiled testimony of Michael Galtman, Noah Russell, Nicholas Crowley, Kim Estrada, Vikrant Gadgil, Devon Rudloff-Daffinson, Wraye Grimard, William Haffecke, Michelle Napier, and John Taylor was admitted into the record as though read. Mike Cassel and Jim Dean testified on behalf of FPUC and the Jackson County intervenors, respectively. Written statements on behalf of both witnesses were also placed in the record as though read without objection. Additionally, 97 exhibits were admitted into the record. The parties waived briefs and a bench vote was taken at the final hearing approving the 2025 Settlement.

DISCUSSION

In evaluating a proposed unanimous 2025 Settlement we must identify the major elements of the proposed settlement, discuss how those elements differ from what was originally proposed in the rate case filing, and discuss the impact the major elements have on the rate case. Once that analysis is done, we must determine whether, when taken as a whole, the settlement is in the public interest.³

The major elements of the 2025 Settlement are as follows:

A. Base revenue increase

FPUC originally requested a \$12,593,450 base revenue increase. The 2025 Settlement sets the base revenue increase at \$8.4 million. The 2025 Settlement divides the base rate

¹ Order No. PSC-2024-0441-PCO-EI, issued October 4, 2024, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

² Order No. PSC-2025-0114-PAA-EI, issued April 7, 2025, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

³ *Floridians Against Increased Rates v. Clark*, 371 So. 3d 905 (Fla. 2023).

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increase into 2 parts: a \$7.4 million increase starting on March 20, 2025 to March 19, 2026 and the final \$8.4 million increase starting March 20, 2026, with a minimum term ending September 20, 2028.

In addition to the base revenue increases, an increase in miscellaneous charges of \$164,495 will be charged from March 20, 2025 until the next rate proceeding. Also from March 20, 2026 until March 20, 2028, \$333,000 per year (1/3 of the deferred first year's \$1 million) will be added to the base revenues of \$8.4 million. Finally, 1/3 of the difference between the PAA rates collected from March 20, 2025 until July 2, 2025, plus interest, will be subtracted from the base revenue requirement starting on March 20, 2026 and ending March 20, 2028.

The structure of the base revenue increase is directly responsive to the testimony given at the service hearings in both Fernandina Beach and Marianna. Both commercial and residential customers testified that they could not absorb the proposed base rate increase of 44% all at one time. Likewise, Jackson County, the Jackson County School Board, and the City of Marianna all testified that if the base revenue increase proposed were to be put in place, the economic impact on Jackson County, one of the poorest counties in the state, would be catastrophic. The School Board testified that it would be unable to fill needed teaching positions and would have to cancel existing school programs. Reducing the base revenue increase by approximately \$4.2 million in 2025 reduces the base rate increase to a 26% for residential customers, a more manageable increase.

B. Miscellaneous fees and charges increase

The proposed increase in fees and charges of \$164,495 in the 2025 Settlement are those proposed by FPUC and consist of customer disconnect and reconnect fees, collection charges, temporary service charges and miscellaneous charges. Upon review, we find these to be reasonable.

C. Effective date of tariffs

FPUC did not request a specific effective date for implementation of its requested revenue increase. The 2025 Settlement delays collection of the full \$8.4 million base revenue increase by 1 year, until March 20, 2026. This allows the customers an opportunity to budget for the increase and make other financial adjustments to accommodate the higher rates.

D. Substations and transmission assets step increase
Step increase tariffs

FPUC originally requested \$678,271 for the acquisition and replacement of four substations and a transmission line in its Northwest territory and replacement/rebuild of two FPUC-owned substations in its Northeast territory. The replacement and acquisition of the Northwest assets is expected to total \$10.7 million and will result in annual savings of approximately \$1.4 million generated by reduced purchased power costs and a reduced fuel factor. In the Northeast, FPUC is replacing two substations originally installed in the 1970s. These projects are expected to cost a total of \$8.7 million.

The 2025 Settlement allows FPUC to implement a base revenue increase when these substation and transmission assets are brought on line which shall not exceed \$727,778. FPUC also requests that our staff be allowed to approve the step increases associated with these assets

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administratively upon confirmation that the rates proposed will produce the correct revenues. These upgrades and purchases will provide increased reliability for both the Northeast and Northwest regions and provide significantly lower fuel costs.

E. Midpoint ROE and ROE range

FPUC requested an ROE of 11.30% with a range of 10.30% to 12.30%. The 2025 Settlement has an ROE of 10.20% with a range of 9.20% to 11.20%. FPUC's calculation of ROE relied heavily on historical financial and market data from 2021 to 2023 that does not accurately reflect expected market conditions or investor required equity returns.

The 2025 Settlement's ROE of 10.20% is consistent with calculations using more recent market data and current forecasted interest rates. A reduction of 110 basis points results in a base revenue reduction of \$848,026.

F. Equity ratio

FPUC proposed an equity ratio of 50.04% for all regulatory purposes which the 2025 Settlement adopted as reasonable for a utility of FPUC's size and risk profile. This equity ratio is within the range of equity ratios for Florida's investor-owned electric (55.53%) and natural gas utilities (53.57%) which average 54.3%.

G. General liability reserve accrual increase

FPUC proposed to increase the general liability (self-insurance) reserve accrual by \$189,432 annually. The 2025 Settlement adopts this amount and requires that the credit balance be used to offset working capital in rate base for all applicable regulatory purposes.

H. Rate case expense

FPUC requested rate case expense of \$1,530,907 amortized over four years. The 2025 Settlement has increased the rate case expense to \$1,536,000 amortized over five years. The 2025 Settlement reflects approximately \$6,000 in additional costs but adds an additional year for cost recovery which lowers the annual expense for customers.

I. Annual storm reserve accrual

FPUC requested an annual storm reserve accrual of \$446,979 amortized over five years until the reserve reaches \$2,234,895. The 2025 Settlement reduced the annual accrual to \$121,620 until the storm reserve reaches \$1.5 million which is what FPUC is currently collecting. Because the 2025 Settlement maintains the current accounting treatment for storm reserve accrual there is no adverse impact imposed by this provision.

J. Minimum term of 2025 Agreement
Next base rate increase

FPUC did not make any representation regarding rate case stay-out provisions or a minimum term in its petition. The 2025 Settlement states that FPUC will not seek a base rate increase until September 20, 2028, unless its earnings fall below 9.2%. This is consistent with the proposed minimum term proposed in the 2025 Settlement of 3½ years, from March 20, 2025 through September 20, 2028.

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Stay-out provisions lock in rates for a set period of time, here 3½ years. This allows ratepayers/businesses to more accurately budget and plan for capital and non-capital expenses.

K. Enhanced customer service measures

FPUC has 33 walk-in payment locations in and around Marianna and 26 walk-in payment locations on Amelia Island. In Marianna 7 locations do not require an additional fee to pay FPUC's bill; on Amelia Island 9 locations do not do so. At both customer hearings there were many requests for FPUC to provide customers with more convenient ways to contact FPUC about billing disputes and to pay bills without incurring additional fees.

The 2025 Settlement has extensive changes to the manner in which customers may pay their bills and get quick responses regarding billing disputes. These consist of enhanced bill and social media messaging, website changes, periodic in-person and remote town hall meetings, public surveys of FPUC's outreach operations, etc. Increased contact with FPUC's customers should go a long way to resolve outstanding issues with customer service.

When taken as a whole, the 2025 Settlement is in the public interest. The 2025 Settlement establishes a \$8.4 million revenue requirement which is 33.3% less than requested by FPUC. This reduction in revenue requirement results in lowering the residential base rate increase from 44% to 26% for residential customers. When coupled with collecting \$7.4 million dollars the first year, the impact of the rate increase is mitigated and allows FPUC's customers time to better accommodate the implementation of the full \$8.4 million rate increase. Establishing a minimum term through September 2028 creates price stability and also allows customers and governmental entities the ability to establish more accurate budgets. Many ratepayers in both Fernandina Beach and Marianna complained about their inability to get timely answers to billing and service complaints from FPUC. The enhanced customer services outlined in the 2025 Settlement are meaningful steps to address this issue.

FPUC's need to provide adequate service and maintain a solid financial structure is addressed by the 2025 Settlement. The 2025 Settlement allows \$727,778 for the construction and purchase of transmission and substation assets in both the Northeast and Northwest divisions necessary to provide cheaper and more reliable service. Likewise, the Company will maintain an equity ratio of 50.04% and return on equity of 10.2%, both within the range of Florida's other electric and natural gas utilities. The 2025 Settlement disposes of all issues in this case which relieves both FPUC and the intervenors from incurring significant additional rate case expense. Finally, the 2025 Settlement allows the implementation of its terms and conditions at an earlier date than would be possible if the case were tried. All parties benefit from implementing the terms and conditions of the 2025 Settlement as soon as possible.

Given these facts, the 2025 Settlement appropriately balances the need for FPUC to have the revenues necessary to provide safe and reliable electric service with the requirement that reliable and safe electric service be provided at the lowest cost to ratepayers. Therefore, we find that the 2025 Settlement, when taken as a whole, is in the public interest and provides rates that are fair, just and reasonable.

Based on the foregoing, it is

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ORDERED that the 2025 Settlement, Attachment A hereto, is hereby approved. It is further

ORDERED that the rates and tariff sheets attached to the 2025 Settlement as Exhibit B are hereby approved effective March 20, 2025.

By ORDER of the Florida Public Service Commission this 24th day of July, 2025.



ADAM J. TEITZMAN
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request:

- 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or
- 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida

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Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

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Attachment A
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida
Public Utilities Company.

DOCKET NO.: 20240099-EI

STIPULATION AND SETTLEMENT

WHEREAS, Florida Public Utilities Company ("FPUC" or "Company"), the City of Marianna, Florida ("City"), Jackson County, Florida ("County"), the Jackson County School Board ("JCSB"), and the Office of Public Counsel ("OPC") have signed this Stipulation and Settlement (the "2025 Agreement"); and

WHEREAS, unless the context clearly intends otherwise, the term "Party" or "Parties" shall mean a signatory or signatories to this 2025 Agreement; and

WHEREAS, the City, the County, the JCSB, and the OPC are collectively referred to herein as the "Consumer Parties;" and

WHEREAS, on August 22, 2024, FPUC filed a Petition with the Florida Public Service Commission ("Commission") seeking approval to increase rates and charges to produce an additional \$12,593,450 in revenues, based upon a projected test year ended December 31, 2025, and requested utilization of the Commission's Proposed Agency Action ("PAA") process; and

WHEREAS, OPC filed a notice of its intervention on September 4, 2024; and

WHEREAS, the Commission issued PAA Order No. PSC-2025-0114-PAA-EI, on April 7, 2025 ("PAA Order"), wherein the Commission approved a reduced increase in base revenues of \$9,675,171, as well as an increase in miscellaneous fees and charges of \$164,495; and

WHEREAS, on March 20, 2025, FPUC increased its base rates to produce increased annual base revenues of \$9,675,171 and increased miscellaneous fees and charges to produce annual base revenues of \$164,495; and

WHEREAS, the Consumer Parties have filed timely filed petitions protesting the PAA order on April 21, 2025 and on April 24, 2025; and

WHEREAS, the Parties have endeavored in good faith to resolve the areas of disagreement in order to provide regulatory certainty with regard to FPUC's rates and to avoid the uncertainty associated with further litigation; and

WHEREAS, the American legal system, as well as the Commission, favor settlement of disputes for many reasons, including that they promote the public interest; and

Docket No. 20240099-EI
Stipulation and Settlement

WHEREAS, the Parties to this 2025 Agreement, individually and collectively, agree that this 2025 Agreement, taken as a whole, is in the public interest;

NOW, THEREFORE, in consideration of the foregoing recitals of fact, which are hereby incorporated into this 2025 Agreement, and the mutual covenants set forth herein, which the Parties agree constitute good and valuable consideration, the Parties hereby stipulate and agree as follows:

I. Term

a. This 2025 Agreement will take effect upon the date that the Commission votes to approve it. The base rates, charges and related tariff sheet terms and conditions established as a result of this 2025 Agreement will be deemed effective as of March 20, 2025, ("Implementation Date") and shall continue through September 20, 2028, and beyond, unless and until changed by Commission Order. The period from the Implementation Date through the billing cycle that includes September 20, 2028, may be referred to herein as the "Minimum Term".

b. The base rates, charges, and related tariff sheet terms and conditions set in accordance with this 2025 Agreement shall not be changed during the Minimum Term, except as otherwise permitted or provided for in this 2025 Agreement, and shall continue in effect until next reset by the Commission.

c. The Parties reserve all rights, unless such rights are expressly waived or released, expressly limited, or expressly eliminated by the terms of this 2025 Agreement.

II. Return on Equity and Equity Ratio

a. For purposes of this 2025 Agreement, the phrase "authorized ROE" shall mean the midpoint authorized return on common equity ("ROE") and the phrase "authorized ROE range" shall mean the range that starts at 100 basis points below the midpoint and extends to 100 basis points above the midpoint as determined in this 2025 Agreement. Consistent with this understanding, FPUC's authorized ROE shall be within an authorized ROE range of 9.20% to 11.20%, with a midpoint of 10.20%. FPUC's equity ratio shall be 50.04% based on investor sources and shall be used for all regulatory purposes including, but not limited to, cost recovery clauses, recovery mechanism(s), earnings surveillance reporting, authorizing a potential exit from this 2025 Agreement pursuant to Paragraph VI, the calculation of the Company's Allowance for Funds Used During Construction ("AFUDC") rate and associated amounts of AFUDC in accordance with Rule 25-

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Stipulation and Settlement

6.0141, Florida Administrative Code, and the implementation and operation of this 2025 Agreement (“Regulatory Purposes”). Customer deposits, investment tax credits, and accumulated deferred income taxes shall be the balances recorded on FPUC’s books.

b. The authorized ROE, authorized ROE range, and equity ratio shall continue in effect until the return on equity is next reset by order of the Commission; however, FPUC may petition the Commission to allow it to reflect a different equity ratio for Regulatory Purposes at any time after the conclusion of the Minimum Term.

III. Revenue Requirement

a. Upon approval of this 2025 Agreement, the authorized annual increase in FPUC’s base revenues initially approved by the PAA Order in the amount of \$9,675,171, shall be reduced to \$8.4 million, excluding the increase in miscellaneous fees and charges of \$164,495, which shall remain in effect, as well as the substation step increase addressed separately herein. The reduction to the authorized base revenue increase will be deemed effective as of March 20, 2025.

b. The Company will defer collection of \$1.0 million of the first year’s agreed base rate revenue increase, such that the first-year level of base rates, effective March 20, 2025, will yield an increase in annual base revenues of \$7.4 million. The deferred \$1.0 million in authorized annual revenues will be collected over the subsequent three-year period through a one-time increase in base rates of \$1.333 million on March 30, 2026, subject to the netting provision in subparagraph (c) herein.

c. Any difference between the amount collected from the rates that originally went into effect on March 20, 2025, with the Commission’s vote of that same date, and the final revenue requirement of \$8.4 million established by this 2025 Agreement, excluding the \$1.0 million deferred reduction, for the period that the higher PAA Order rate levels were in effect (“One-time True-up Period”), will be netted against the \$1.0 million deferral (“Net Deferral”) discussed in Paragraph III b. above, in a manner that spreads the Net Deferral amount evenly over the three-year period beginning March 20, 2026.

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d. The Company will file any step increase calculations resulting from FPUC's acquisition and replacement of the substation and transmission assets addressed in its filing initiating this proceeding. Using a weighted average cost of capital of 6.36%, based upon a 10.20% return on equity midpoint and an equity ratio of 50.04%, the additional allowed revenue requirement associated with these substations and transmission assets, grossed up for taxes, regulatory assessment fees, and bad debt, shall not exceed \$727,778. FPUC shall be authorized to increase its base rates by the incremental revenue requirement, in the manner provided herein, associated with the substation and transmission projects once these assets are placed in service and shall accordingly file an appropriate notice of intent to implement this step increase, including proposed tariff sheets, once the assets are in service. The Parties support the PSC Staff being authorized to approve the step increase tariff sheets administratively, upon their confirmation that the rates therein will produce the correct revenues.

IV. Other Cost Recovery

a. Nothing in this 2025 Agreement shall preclude the Company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly determines are clause recoverable subsequent to the approval of this 2025 Agreement. Except as provided in this 2025 Agreement, it is the intent of the Parties in conjunction with the provisions of this Paragraph IV, that FPUC shall not seek to recover, nor shall FPUC be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery clauses and charges, costs of any type or category that have historically and traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; (ii) new or atypical costs that have not been litigated before the Commission because they were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting FPUC's operations; or (iii) costs that would otherwise be recoverable through base rates that the Florida Legislature has expressly authorized as clause recoverable by public utilities. As part of the base rate freeze agreed to herein, FPUC will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Implementation Date

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Stipulation and Settlement

through and including September 20, 2028, which are of the type that historically or traditionally have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to in a writing signed by each of the Parties. The Parties are not precluded from participating in any proceedings pursuant to this Paragraph IV, nor is any Party precluded from raising any issues pertinent to any such proceeding or the enforcement of this 2025 Agreement.

b. Notwithstanding the anti-deferral language in Paragraph IV a. above, the Company shall retain the ability to capitalize the specific types of costs that are the subject of, and consistent with, the Uniform System of Accounts as specified in Order No. PSC-2022-0429-PAA-PU, and shall also retain its ability to seek recovery of the net unrecovered cost of new LED lights, as specified and contemplated in Order No. PSC-2025-0091-PAA-EI.

V. Storm Damage Recovery

a. Nothing in this 2025 Agreement shall preclude FPUC from petitioning the Commission to seek recovery of costs associated with any tropical systems named by the National Hurricane Center or its successor without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings.

b. Consistent with the rate design and cost allocation methods approved in the PAA Order, the Parties agree that recovery of storm costs from customers will begin, on an interim basis (subject to refund following a hearing or a full opportunity for a formal proceeding), sixty days following the filing by FPUC of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed \$4.00 per 1,000 kWh on monthly residential customer bills. In the event FPUC's reasonable and prudent storm costs exceed that level, any additional costs in excess of \$4.00 per 1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. All storm related costs shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and shall be limited to (i) costs resulting from a tropical system named by the National Hurricane Center or its successor, (ii) the estimate of incremental costs above the level of storm reserve prior to the storm

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and (iii) the replenishment of FPUC's storm reserve to the level as of March 20, 2025 with the use of this storm cost recovery mechanism. The Parties to this 2025 Agreement are not precluded from participating in any such proceedings and opposing the amount of FPUC's claimed costs or whether the proposed recovery is consistent with this Paragraph V, but not the mechanism agreed to herein.

c. The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of FPUC and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

d. The provisions of this Paragraph V shall remain in effect during the Minimum Term except as otherwise permitted or provided for in this 2025 Agreement and shall continue in effect until the Company's base rates are next reset by the Commission. For clarity, this means that if this 2025 Agreement is terminated pursuant to Paragraph VI hereof, FPUC's rights regarding storm cost recovery under this 2025 Agreement are terminated at the same time, except that any Commission-approved surcharge then in effect shall remain in effect until the costs subject to that surcharge are fully recovered. A storm surcharge in effect without approval of the Commission shall be terminated at the time this 2025 Agreement is terminated pursuant to Paragraph VI herein.

VI. Earnings

a. Notwithstanding Paragraph II-Return on Equity and Equity Ratio, the Parties agree that, in the event that the Company's earned return on common equity falls below 9.20% during the Minimum Term on an FPUC compliant monthly earnings surveillance report stated on a thirteen-month average actual Commission adjusted basis, the Company may file a Petition for Rate Increase with the Commission either as a general proceeding under Sections 366.06 and 366.07, Florida Statutes, or as a limited proceeding under Section 366.076, Florida Statutes. Nothing herein shall be construed as an agreement by any of the Consumer Parties that a limited proceeding would be appropriate, and FPUC acknowledges and agrees that the Consumer Parties reserve and retain their individual and collective rights to challenge the propriety of any limited proceeding or to assert that any request for base rate changes should be properly addressed through a general rate case, as well as challenge any substantive proposals to change the Company's rates in any such future proceeding.

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Throughout this 2025 Agreement, “actual Commission adjusted basis” and “actual adjusted earned return” shall mean results reflecting all adjustments to FPUC’s books required by the Commission by rule or order. FPUC acknowledges that the Consumer Parties shall be entitled to participate and oppose any request initiated by FPUC to increase its rates.

b. Likewise, notwithstanding Paragraph II-Return on Equity and Equity Ratio, the Parties agree that if the Company’s earned return on common equity exceeds 11.20% on an FPUC compliant monthly earnings surveillance report stated on a thirteen-month average actual Commission-adjusted basis, as further described and defined in subparagraph (a) herein, any Consumer Party may file a petition with the Commission seeking a review of the Company’s rates. In any case initiated by any of the Consumer Parties, all Parties will have full rights conferred by law.

c. This Paragraph VI shall not: (i) be construed to bar FPUC from requesting any recovery of costs otherwise contemplated by this 2025 Agreement, (ii) apply to any request to change FPUC’s base rates that would become effective after the expiration of the Minimum Term of this 2025 Agreement, or (iii) limit any Party’s rights in proceedings concerning changes to base rates that would become effective subsequent to the Minimum Term of this 2025 Agreement to argue that FPUC’s authorized ROE range should be different than as set forth in this 2025 Agreement.

VII. General Liability Reserve

a. The Parties agree that FPUC shall be authorized to increase its General Liability Reserve (“self-insurance”) reserve annual accrual by \$189,432.

b. The Company shall continue to report the annual balance of the general liability reserve in its annual report to the Commission, and the credit balance shall be used to offset working capital in rate base for all applicable regulatory purposes.

VIII. Rate Case Expense

Rate case expense in an amount not to exceed \$1,536,000 shall be amortized over a 5-year period.

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Stipulation and Settlement

IX. Storm Accrual

The Company shall maintain its annual accrual of \$121,620 to its Storm Reserve until the existing target of \$1.5 million is achieved.

X. Enhanced Local Presence

a. The Parties hereto acknowledge that Company provides thirty-three (33) walk-in payment locations in and around Marianna (NW Division). Of those locations, seven (7) do not require an additional fee. On Amelia Island, the Company provides twenty-six (26) walk-in payment locations, of which nine (9) do not charge an additional fee. To improve the process of paying bills at these walk-in locations, a bar code has been added to the back of all billing statements.

b. The Company commits to add enhanced bill messaging, social media messaging, and website visibility sharing the identities and locations of these payment centers. The Company will also promote an enhanced customer support email option for Florida electric customers at customersupport@FPUC.com, which is already available to customers.

c. The Company will host periodic virtual townhall meetings for its customers, at mutually agreeable times, which will provide customers with an opportunity to speak directly with members of FPUC's team, which will include, as may be necessary, members of the Customer Care team, Operations, and Billing and Accounts team members. Customers will be able to interact with these team members via a live video feed. These sessions may, as necessary, also include break-out sessions to protect customers' identifying and account information.

d. The Company will also host periodic in-person townhall meetings in each service territory. It is the intent of the Parties hereto that the Company conduct one to two such meetings per year, as scheduling allows, in each service territory at mutually agreeable times. Noticing for such meetings will be provided in bill inserts, as well as publication in local newspapers within 7 days of such an event.

e. The Parties also agree that conducting such in-person, townhall meeting will be considered a pilot initiative, and the Company will provide follow-up reports to the Consumer Parties

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and the Commission regarding the effectiveness of these events, including, but not limited to, participation by customers.

f. In addition, the Company will, at a minimum, conduct semi-annual reviews of the effectiveness of actions listed above, including conducting periodic surveys to gather customer feedback to help guide the Company's continuing improvement efforts.

XI. Effective Date

Consistent with the Minimum Term set forth in Paragraph I-Term, the Parties agree that the rates to be implemented as a result of this 2025 Agreement shall be deemed to have gone into effect on March 20, 2025.

XII. Commission Approval

a. The provisions of this 2025 Agreement are contingent upon Commission approval of this 2025 Agreement in its entirety without modification. It is the desire of the Parties that this 2025 Agreement be noticed for consideration and a Commission decision as soon as possible, but in any event, no later than June 6, 2025. The Parties agree that:

- i. Consideration by the Commission of this 2025 Agreement at an appropriately noticed hearing, at which all interested persons are allowed to speak to address the 2025 Agreement, satisfies the applicable requirements of Chapter 120, Florida Statutes, for Commission action on the approval of the 2025 Agreement; and
- ii. The Commission's decision approving this 2025 Agreement may be issued as a final order.

b. The Parties agree that there is good cause to expedite approval of this 2025 Agreement, in that approval of the 2025 Agreement will avoid additional litigation costs for all Parties. To the extent necessary, the Parties agree to waive:

- i. Their right to require a hearing on the merits;
- ii. Their respective rights to seek reconsideration of any Final Order that approves this 2025 Agreement in its entirety without change; and

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Stipulation and Settlement

- iii. Their respective right to judicial review of any such final agency action approving this 2025 Agreement afforded by Section 120.68, Florida Statutes.

c. The Parties further agree they will support this 2025 Agreement and affirmatively assert that this 2025 Agreement is in the public interest and should be approved. The Parties likewise agree and acknowledge that:

- i. The revenue increase and resulting rates and charges developed from and in accordance with this 2025 Agreement are fair, just and reasonable; and
- ii. Approval of this 2025 Agreement promotes planning and regulatory certainty for both FPUC and its customers.

Approval of this 2025 Agreement in its entirety resolves all matters in Docket No. 20240099-EI addressed herein and the Docket will be closed effective on the date the Commission's order approving this 2025 Agreement becomes final and no longer subject to appeal.

d. No Party will assert in any proceeding before the Commission or before any court that this 2025 Agreement or any of the terms in this 2025 Agreement shall have any precedential value. The Parties' agreement to the terms in this 2025 Agreement shall be without prejudice to any Party's ability to advocate a position that differs from the terms of this Agreement in future proceedings not involving this 2025 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2025 Agreement by virtue of that Party's signature on, or participation in, this 2025 Agreement. It is the intent of the Parties to this 2025 Agreement that the Commission's approval of all the terms and provisions of this 2025 Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this 2025 Agreement endorses a specific provision, in isolation, of this 2025 Agreement by virtue of that Party's signature on, or participation in, this 2025 Agreement.

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XIII. Disputes

To the extent a dispute arises between or among the Parties about the provisions, interpretation, or application of this 2025 Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute within 30 days following such conferral, the matter may be submitted to the Commission for resolution.

XIV. Resolution of Issues

Approval of this 2025 Agreement resolves all issues in this proceeding, with the exception of issues regarding Cost of Service and Rate Design. The Consumer Parties take no position on the Cost of Service and Rate Design issues.

XV. New Rates

a. The New Rates for Year 1, calculated in accordance with Paragraph III of this 2025 Agreement and which are attached and incorporated herein as Exhibit A, shall be designed to accurately reflect the terms as presented in the 2025 Agreement, at the time of implementation. In addition, the New Rates presented in Exhibit A shall be designed in accordance with the methodology of the Cost of Service and Rate Design approved by the PAA Order, as shall each subsequent rate increase reflected herein. Tariffs reflective of the rates that will be effective March 20, 2026 and for the subsequent years of the Minimum Term will be provided within 90 days of the date a Commission Order approving this 2025 Agreement becomes final. Such rates will be reflective of the subsequent years' revenue requirements, as provided for in this 2025 Agreement, as reflected in Paragraph III, as well as the one-time netting of any overcollection, during the One-time True-up Period, in accordance with Paragraph III b. and c..

b. The Consumer Parties take no position with regard to the design of the rates and new service charges reflected therein, consistent with Paragraph XIV-Resolution of Issues, above.

c. Attached hereto and incorporated herein as Exhibit B are the appropriate tariff sheets reflecting these rate changes, which, upon Commission approval, shall become effective as of March 20, 2025.

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XVI. Execution

This 2025 Agreement is dated as of May 5, 2025. It may be executed in one (1) or more counterparts, all of which will be considered one and the same 2025 Agreement and each of which will be deemed an original.

[SIGNATURE PAGES FOLLOW]

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IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2025 Agreement by their signature(s).

Dated this 5 day of May, 2025.

Florida Public Utilities Company

By: 

Michael D. Cassel, Vice President/Governmental and Regulatory Affairs/Chesapeake Utilities Corporation

Signature Page to Stipulation and Settlement Agreement in Docket No. 20240099-EI

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IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2025 Agreement by their signature(s).

Dated this __ day of May 2025

Office of Public Counsel



Walt Trierweiler, Public Counsel
Patricia A. Christensen
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399-1400

Signature Page to Stipulation and Settlement Agreement in Docket No. 20240099-EI

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IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2025 Agreement by their signature(s).

Dated this 1st day of May, 2025

City of Marianna, Florida



Rico Williams, Mayor
City of Marianna

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2025 Agreement by their signature(s).

Dated this 5th day of May 2025

Jackson County, Florida



Hon. Jamey Westbrook, Chairman
Jackson County Board of County
Commissioners

Attested by:



Clayton O. Rooks, Clerk

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IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2025 Agreement by their signature(s).

Dated this 16th day of May 2025

Jackson County School Board


Chris Johnson, Chairperson
Jackson County School Board

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EXHIBIT A

	<u>PAA Rates</u>	<u>Final Settlement Rates</u>
		<u>Customer Charge(s)</u>
Residential (RS)	\$24.40	\$24.40
General Service (GS)	\$40.00	\$40.00
General Service Demand (GSD)	\$126.44	\$117.99
General Service Large Demand (GSLD)	\$241.70	\$225.55
General Service Large Demand (GSLD1)	\$1,183.57	\$1,104.48
Standby (SB)	N/A	N/A
		<u>Energy Charge \$/kwh</u>
Residential (RS) ≤1,000	\$.03042	\$.02696
>1,000	\$.04983	\$.04415
General Service (GS)	\$.04668	\$.04152
General Service Demand (GSD)	\$.00840	\$.00784
General Service Large Demand (GSLD)	\$.00390	\$.00364
General Service Large Demand (GSLD1)	\$.00000	\$.00000
Standby (SB) <500 kw	N/A	N/A
Standby (SB) ≥500 kw	N/A	N/A
		<u>Demand Charge \$/kw</u>
Residential (RS)	\$ 0.00	\$ 0.00
General Service (GS)	\$ 0.00	\$ 0.00
General Service Demand (GSD)	\$ 6.89	\$ 6.43
General Service Large Demand (GSLD)	\$ 9.86	\$ 9.20
General Service Large Demand (GSLD1)	\$ 2.74	\$ 2.56
General Service Large Demand (GSLD1)	\$ 0.53 kVAR	\$ 0.50 kVAR
Standby (SB)	N/A	N/A

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Outdoor/Street Lighting various various

	PAA RATES				FINAL SETTLEMENT RATES			
	Facility	Energy	Maint	Total	Facility	Energy	Maint	Total
	Charge	Charge	Charge	Charge	Charge	Charge	Charge	Charge
150w HPS Acorn	\$23.91	\$3.87	\$3.02	\$30.80	\$22.31	\$3.61	\$2.82	\$28.74
150w HPS ALN 440	\$34.08	\$3.87	\$4.03	\$41.98	\$31.80	\$3.61	\$3.76	\$39.17
100w HPS Amer Rev	\$11.73	\$2.61	\$3.99	\$18.33	\$10.95	\$2.44	\$3.73	\$17.12
150w HPS Am Rev	\$10.99	\$3.87	\$4.04	\$18.90	\$10.25	\$3.61	\$3.77	\$17.63
100w HPS Cobra Head	\$8.80	\$2.61	\$2.56	\$13.97	\$8.21	\$2.44	\$2.39	\$13.04
200w HPS Cobra Head	\$11.87	\$5.17	\$3.07	\$20.11	\$11.08	\$4.83	\$2.87	\$18.78
250w HPS Cobra Head	\$14.12	\$6.44	\$4.04	\$24.60	\$13.18	\$6.01	\$3.77	\$22.96
400w HPS Cobra Head	\$13.19	\$10.37	\$3.36	\$26.92	\$12.30	\$9.68	\$3.14	\$25.12
250w HPS Flood	\$13.81	\$6.44	\$2.94	\$23.19	\$12.88	\$6.01	\$2.74	\$21.63
400w HPS Flood	\$21.67	\$10.37	\$2.76	\$34.80	\$20.22	\$9.68	\$2.57	\$32.47
1000w HPS Flood	\$27.15	\$25.86	\$3.64	\$56.65	\$25.33	\$24.13	\$3.40	\$52.86
100w HPS SP2 Spectra	\$30.12	\$2.61	\$3.76	\$36.49	\$28.11	\$2.44	\$3.51	\$34.06
175w MH ALN 440	\$32.61	\$4.58	\$3.17	\$40.36	\$30.43	\$4.27	\$2.96	\$37.66
400w MH Flood	\$14.72	\$10.37	\$2.68	\$27.77	\$13.73	\$9.68	\$2.50	\$25.91
1000w MH Flood	\$25.02	\$25.86	\$3.55	\$54.43	\$23.35	\$24.13	\$3.31	\$50.79
175w MH Shoebox	\$27.54	\$4.58	\$3.56	\$35.68	\$25.70	\$4.27	\$3.32	\$33.29
250w MH Shoebox	\$29.31	\$6.44	\$3.98	\$39.73	\$27.35	\$6.01	\$3.72	\$37.08
100w MH SP2 Spectra	\$29.89	\$2.61	\$3.64	\$36.14	\$27.90	\$2.44	\$3.40	\$33.74
1000w MH Vert Shoebox	\$30.90	\$25.86	\$4.03	\$60.79	\$28.84	\$24.13	\$3.76	\$56.73
175w MV Cobra Head-OL	\$1.69	\$4.49	\$1.51	\$7.69	\$1.57	\$4.19	\$1.40	\$7.16
400w MV Cobra Head-OL	\$1.86	\$9.65	\$1.60	\$13.11	\$1.73	\$9.01	\$1.50	\$12.24
50W Outdoor Light (100W Equivalent)	\$7.99	\$1.08	\$2.53	\$11.60	\$7.46	\$1.01	\$2.36	\$10.83
50W Cobra Head (100W Equivalent)	\$10.09	\$1.08	\$3.14	\$14.31	\$9.42	\$1.01	\$2.93	\$13.36
82W Cobra Head (200W Equivalent)	\$9.45	\$1.78	\$2.95	\$14.18	\$8.82	\$1.67	\$2.75	\$13.24
130W Cobra Head (250W Equivalent)	\$9.41	\$2.87	\$2.94	\$15.22	\$8.78	\$2.67	\$2.74	\$14.19

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	PAA RATES				FINAL SETTLEMENT RATES			
	Facility Charge	Energy Charge	Maint Charge	Total Charge	Facility Charge	Energy Charge	Maint Charge	Total Charge
210W Cobra Head (400W Equivalent)	\$16.45	\$4.59	\$4.80	\$25.84	\$15.35	\$4.28	\$4.48	\$24.11
36W American Revolution Decorative (100W Equivalent)	\$9.45	\$0.57	\$3.30	\$13.32	\$8.82	\$0.53	\$3.08	\$12.43
44W American Revolution Decorative (150W Equivalent)	\$9.36	\$0.96	\$3.27	\$13.59	\$8.74	\$0.90	\$3.05	\$12.69
90W Acorn Decorative (150W Equivalent)	\$13.53	\$1.98	\$4.50	\$20.01	\$12.62	\$1.85	\$4.20	\$18.67
60W Post Top Decorative (150W Equivalent)	\$23.97	\$1.34	\$7.59	\$32.90	\$22.37	\$1.25	\$7.08	\$30.70
80W Flood (250W Equivalent)	\$13.11	\$1.72	\$4.13	\$18.96	\$12.24	\$1.61	\$3.85	\$17.70
170W Flood (400W Equivalent)	\$13.11	\$3.70	\$4.13	\$20.94	\$12.24	\$3.46	\$3.85	\$19.55
150W Flood (350W Equivalent)	\$13.11	\$3.31	\$4.13	\$20.55	\$12.24	\$3.09	\$3.85	\$19.18
290W Flood (1,000W Equivalent)	\$13.11	\$6.37	\$4.13	\$23.61	\$12.24	\$5.95	\$3.85	\$22.04
82W Shoe Box (175W Equivalent)	\$11.56	\$3.31	\$3.92	\$18.79	\$10.79	\$3.09	\$3.66	\$17.54
131W Shoe Box (250W Equivalent)	\$13.02	\$2.87	\$4.36	\$20.25	\$12.15	\$2.67	\$4.07	\$18.89
150W Shoe Box	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
10' Alum Deco Base	\$22.53	\$0.00	\$0.00	\$22.53	\$21.03	\$0.00	\$0.00	\$21.03
13' Decorative Concrete	\$17.17	\$0.00	\$0.00	\$17.17	\$16.02	\$0.00	\$0.00	\$16.02
18' Fiberglass Round	\$12.12	\$0.00	\$0.00	\$12.12	\$11.31	\$0.00	\$0.00	\$11.31
20' Decorative Concrete	\$19.92	\$0.00	\$0.00	\$19.92	\$18.59	\$0.00	\$0.00	\$18.59
30' Wood Pole Std	\$6.51	\$0.00	\$0.00	\$6.51	\$6.07	\$0.00	\$0.00	\$6.07
35' Concrete Square	\$19.22	\$0.00	\$0.00	\$19.22	\$17.94	\$0.00	\$0.00	\$17.94
40' Wood Pole Std	\$13.02	\$0.00	\$0.00	\$13.02	\$12.15	\$0.00	\$0.00	\$12.15
30' Wood pole	\$5.85	\$0.00	\$0.00	\$5.85	\$5.46	\$0.00	\$0.00	\$5.46

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EXHIBIT B

Revised Tariff Sheets
For Florida Public Utilities Company

(clean/legislative)

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.001
Cancels Original Sheet No. 7.001

*RATE SCHEDULE RS
RESIDENTIAL SERVICE*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable for service to a single family dwelling unit occupied by one family or household and for energy used in commonly-owned facilities in condominium and cooperative apartment buildings.

Character of Service

Single-phase service at nominal secondary voltage of 115/230 volts; three-phase service if available.

Limitations of Service

The maximum size of any individual single-phase motor hereunder shall not exceed five (5) horsepower.

The Company shall not be required to construct any additional facilities for the purpose of supplying three-phase service unless the revenue to be derived therefrom shall be sufficient to yield the Company a fair return on the value of such additional facilities.

Monthly Rate

Customer Facilities Charge:

\$24.40 per Customer per month

Base Energy Charge:

2.696¢/KWH for usage up to 1000 KWH's/month

4.415¢/KWH for usage above 1000 KWH's/month

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company

7.001

F.P.S.C. Electric Tariff

Original Volume No. II

First Revised Sheet No.

Cancels Original Sheet No. 7.001

*RATE SCHEDULE RS
RESIDENTIAL SERVICE*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable for service to a single family dwelling unit occupied by one family or household and for energy used in commonly-owned facilities in condominium and cooperative apartment buildings.

Character of Service

Single-phase service at nominal secondary voltage of 115/230 volts; three-phase service if available.

Limitations of Service

The maximum size of any individual single-phase motor hereunder shall not exceed five (5) horsepower.

The Company shall not be required to construct any additional facilities for the purpose of supplying three-phase service unless the revenue to be derived therefrom shall be sufficient to yield the Company a fair return on the value of such additional facilities.

Monthly Rate

Customer Facilities Charge:

\$24.40 per Customer per month

Base Energy Charge:

~~2.6963-042¢~~/KWH for usage up to 1000 KWH's/month

~~4.4154-983¢~~/KWH for usage above 1000 KWH's/month

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.004
Cancels Original Sheet No. 7.004

RATE SCHEDULE GS
GENERAL SERVICE – NON DEMAND

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties
And on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial lighting, heating, cooking and small power loads aggregating
25 KW or less.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point.

Monthly Rate

Customer Facilities Charge:

\$40.00 per Customer per month

Base Energy Charge:

All KWH 4.152¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in
January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company
7.004

First Revised Sheet No.
Cancels Original Sheet No. 7.004

F.P.S.C. Electric Tariff
Original Volume No. II

RATE SCHEDULE GS
GENERAL SERVICE – NON DEMAND

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties
And on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial lighting, heating, cooking and small power loads aggregating
25 KW or less.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point.

Monthly Rate

Customer Facilities Charge:

\$40.00 per Customer per month

Base Energy Charge:

All KWH 4.1524-668¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in
January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.006
Cancels Original Sheet No. 7.006

RATE SCHEDULE GSD
GENERAL SERVICE – DEMAND

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 25 KW but less than 500 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 25 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:
\$117.99 per Customer per month

Demand Charge:
Each KW of Billing Demand \$6.43/KW

Base Energy Charge
All KWH 0.784¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet Nos. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company
7.006

First Revised Sheet No.
Cancels Original Sheet No. 7.006

F.P.S.C. Electric Tariff
Original Volume No. II

RATE SCHEDULE GSD
GENERAL SERVICE – DEMAND

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 25 KW but less than 500 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 25 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:

~~\$126.44~~ 117.99 per Customer per month

Demand Charge:

Each KW of Billing Demand ~~\$6.896~~ 43/KW

Base Energy Charge

All KWH 0. ~~840784~~ ¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet Nos. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.008
Cancels Original Sheet No. 7.008

RATE SCHEDULE GSLD
GENERAL SERVICE-LARGE DEMAND

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 500 KW but less than 5000 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 500 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:

\$225.55 per Customer per month

Demand Charge:

Each KW of Billing Demand \$9.20/KW

Base Energy Charge

All KWH 0.364¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet No. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

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Florida Public Utilities Company
7.008

First Revised Sheet No.
Cancels Original Sheet No. 7.008

F.P.S.C. Electric Tariff
Original Volume No. II

*RATE SCHEDULE GSLD
GENERAL SERVICE-LARGE DEMAND*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 500 KW but less than 5000 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 500 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:

~~\$241.70~~ 225.55 per Customer per month

Demand Charge:

Each KW of Billing Demand \$9. ~~86~~ 20/KW

Base Energy Charge

All KWH 0. ~~390364~~ ¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet No. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.010
Cancels Original Sheet No. 7.010

RATE SCHEDULE GSLD 1
GENERAL SERVICE - LARGE DEMAND 1

Availability

Available within the territory served by the Company in Jackson, Calhoun, and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial services of Customers contracting for at least 5,000 kilowatts of electric service.

Character of Service

Three-phase, 60 hertz, electric service delivered and metered at a single point at the available transmission voltage, nominally 69,000 volts or higher.

Monthly Base Rates

Customer Facilities Charge:	\$1,104.48
Base Transmission Demand Charge:	\$2.56/KW of Maximum/NCP Billing Demand
Excess Reactive Demand Charge:	\$0.50 kVar of Excess Reactive Demand

Purchased Power Charges

Purchased power charges are adjusted by the FPSC annually. Current purchased power rates are listed on Sheet Nos. 7.021 and 7.022. The Purchased Power Charges recover Energy and Demand Charges billed to FPUC by FPUC's Wholesale Energy Provider and Wholesale Cogeneration Provider including applicable line losses and taxes. See Sheet Nos. 7.010 and 7.011 for the methodology used to determine purchased power rate and calculation to develop annual true-up calculations.

Minimum Bill

The minimum monthly bill is the sum of the Transmission Demand Charge and the Customer Charge plus any Purchased Power Charges attributed to Transmission Demand Fuel Charge.

Terms of Payment

Bills are rendered net and due and payable within twenty (20) days from date of bill.

Conservation Costs

Not applicable.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

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Florida Public Utilities Company
7.010
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No.
Cancels Original Sheet No. 7.010

RATE SCHEDULE GSLD 1
GENERAL SERVICE - LARGE DEMAND 1

Availability

Available within the territory served by the Company in Jackson, Calhoun, and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial services of Customers contracting for at least 5,000 kilowatts of electric service.

Character of Service

Three-phase, 60 hertz, electric service delivered and metered at a single point at the available transmission voltage, nominally 69,000 volts or higher.

Monthly Base Rates

Customer Facilities Charge:	~~\$1,183.57~~ <u>\$1,104.48</u>
Base Transmission Demand Charge:	~~\$2,742.56~~ <u>\$2,742.56</u> /KW of Maximum/NCP Billing Demand
Excess Reactive Demand Charge:	~~\$0.5350~~ <u>\$0.5350</u> kVar of Excess Reactive Demand

Purchased Power Charges

Purchased power charges are adjusted by the FPSC annually. Current purchased power rates are listed on Sheet Nos. 7.021 and 7.022. The Purchased Power Charges recover Energy and Demand Charges billed to FPUC by FPUC's Wholesale Energy Provider and Wholesale Cogeneration Provider including applicable line losses and taxes. See Sheet Nos. 7.010 and 7.011 for the methodology used to determine purchased power rate and calculation to develop annual true-up calculations.

Minimum Bill

The minimum monthly bill is the sum of the Transmission Demand Charge and the Customer Charge plus any Purchased Power Charges attributed to Transmission Demand Fuel Charge.

Terms of Payment

Bills are rendered net and due and payable within twenty (20) days from date of bill.

Conservation Costs

Not applicable.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Issued by: Jeffrey Sylvester, Chief Operating Officer
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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.013
Cancels Original Sheet No. 7.013

RATE SCHEDULE LS
LIGHTING SERVICE

Availability

Available within the territory served by the Company in Calhoun, Jackson and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to any Customer for non-metered outdoor lighting service.

Character of Service

Lighting service from dusk to dawn as described herein.

Limitations of Service

Service is limited to lighting by high-pressure sodium vapor, metal halide, or light emitting diode lamps mounted on Company-owned poles as described herein. Company-owned facilities will be installed only on Company-owned poles.

Monthly Rate

When lighting fixtures are mounted on existing poles and served directly from existing overhead secondary distribution lines:

Type	Lamp	Size	KWH/Mo.	Facilities	Maintenance*	Energy	Total
<u>Facility</u>	<u>Lumens</u>	<u>Watts</u>	<u>Estimate</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>
<u>High Pressure Sodium Lights (CLOSED TO NEW CUSTOMERS)</u>							
Acorn	16,000	150	61	\$22.31	\$2.82	\$3.61	\$28.74
ALN 440	16,000	150	61	\$31.80	\$3.76	\$3.61	\$39.17
Amer. Rev.	9,500	100	41	\$10.95	\$3.73	\$2.44	\$17.12
Amer. Rev.	16,000	150	61	\$10.25	\$3.77	\$3.61	\$17.63
Cobra Head	9,500	100	41	\$8.21	\$2.39	\$2.44	\$13.04
Cobra Head	22,000	200	81	\$11.08	\$2.87	\$4.83	\$18.78
Cobra Head	28,500	250	101	\$13.18	\$3.77	\$6.01	\$22.96
Cobra Head	50,000	400	162	\$12.30	\$3.14	\$9.68	\$25.12
Flood	28,500	250	101	\$12.88	\$2.74	\$6.01	\$21.63
Flood	50,000	400	162	\$20.22	\$2.57	\$9.68	\$32.47
Flood	130,000	1,000	405	\$25.33	\$3.40	\$24.13	\$52.86
SP2 Spectra	9,500	100	41	\$28.11	\$3.51	\$2.44	\$34.06
<u>Metal Halide Lights (CLOSED TO NEW CUSTOMERS)</u>							
ALN 440	16,000	175	71	\$30.43	\$2.96	\$4.27	\$37.66
Flood	50,000	400	162	\$13.73	\$2.50	\$9.68	\$25.91
Flood	130,000	1,000	405	\$23.35	\$3.31	\$24.13	\$50.79
Shoebox	16,000	175	71	\$25.70	\$3.32	\$4.27	\$33.29
Shoebox	28,500	250	101	\$27.35	\$3.72	\$6.01	\$37.08
SP2 Spectra	9,500	100	41	\$27.90	\$3.40	\$2.44	\$33.74
Vertical Shoebox	130,000	1,000	405	\$28.84	\$3.76	\$24.13	\$56.73

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Florida Public Utilities

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Florida Public Utilities Company
7.013

First Revised Sheet No.
Cancels Original Sheet No. 7.013

F.P.S.C. Electric Tariff
Original Volume No. II

*RATE SCHEDULE LS
LIGHTING SERVICE*

Availability

Available within the territory served by the Company in Calhoun, Jackson and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to any Customer for non-metered outdoor lighting service.

Character of Service

Lighting service from dusk to dawn as described herein.

Limitations of Service

Service is limited to lighting by high-pressure sodium vapor, metal halide, or light emitting diode lamps mounted on Company-owned poles as described herein. Company-owned facilities will be installed only on Company-owned poles.

Monthly Rate

When lighting fixtures are mounted on existing poles and served directly from existing overhead secondary distribution lines:

Type	Lamp	Size	KWH/Mo.	Facilities	Maintenance*	Energy	Total
Facility	Lumens	Watts	Estimate	Charge	Charge	Charge	Charge
High Pressure Sodium Lights (CLOSED TO NEW CUSTOMERS)							
Acorn	16,000	150	61	\$23.9122.31	\$3.022.82	\$3.873.61	\$30.8028.74
ALN 440	16,000	150	61	\$34.0831.80	\$4.033.76	\$3.873.61	\$41.9839.17
Amer. Rev.	9,500	100	41	\$11.7310.95	\$3.993.73	\$2.612.44	\$18.3317.12
Amer. Rev.	16,000	150	61	\$10.9910.25	\$4.043.77	\$3.873.61	\$18.9017.63
Cobra Head	9,500	100	41	\$8.808.21	\$2.562.39	\$2.612.44	\$13.9713.04
Cobra Head	22,000	200	81	\$11.8711.08	\$3.072.87	\$5.174.83	\$20.1118.78
Cobra Head	28,500	250	101	\$14.1213.18	\$4.043.77	\$6.446.01	\$24.6022.96
Cobra Head	50,000	400	162	\$13.19 12.30	\$3.363.14	\$10.379.68	\$26.9225.12
Flood	28,500	250	101	\$13.8112.88	\$2.942.74	\$6.446.01	\$23.1921.63
Flood	50,000	400	162	\$21.6720.22	\$2.762.57	\$10.379.68	\$34.8032.47
Flood	130,000	1,000	405	\$27.1525.33	\$3.643.40	\$25.8624.13	\$56.6552.86
SP2 Spectra	9,500	100	41	\$30.1228.11	\$3.763.51	\$2.612.44	\$36.4934.06
Metal Halide Lights (CLOSED TO NEW CUSTOMERS)							
ALN 440	16,000	175	71	\$32.6130.43	\$3.172.96	\$4.584.27	\$40.3637.66
Flood	50,000	400	162	\$14.7213.73	\$2.682.50	\$10.379.68	\$27.7725.91
Flood	130,000	1,000	405	\$25.0223.35	\$3.553.31	\$25.8624.13	\$54.4350.79
Shoebox	16,000	175	71	\$27.5425.70	\$3.563.32	\$4.584.27	\$35.6833.29
Shoebox	28,500	250	101	\$29.3127.35	\$3.983.72	\$6.446.01	\$39.7337.08
SP2 Spectra	9,500	100	41	\$29.8927.90	\$3.643.40	\$2.612.44	\$36.1433.74
Vertical Shoebox	130,000	1,000	405	\$30.9028.84	\$4.033.76	\$25.8624.13	\$60.7956.73

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

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Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.014
Cancels Original Sheet No. 7.014

*RATE SCHEDULE 1S
LIGHTING SERVICE*

Light Emitting Diode Lights

Type	Charges						
	Facility Type	Lamp Lumens	Size Watts	Est. KWH/Mo.	Facilities	Maintenance	Energy Total
	50W Outdoor Light (100W Equivalent)	5,682	50	17	\$7.46	\$2.36	\$1.01 \$10.83
	50W Cobra Head (100W Equivalent)	5,944	50	17	\$9.42	\$2.93	\$1.01 \$13.36
	82W Cobra Head (200W Equivalent)	9,600	82	28	\$8.82	\$2.75	\$1.67 \$13.24
	130W Cobra Head (250W Equivalent)	14,571	130	45	\$8.78	\$2.74	\$2.67 \$14.19
	210W Cobra Head (400W Equivalent)	28,653	210	72	\$15.35	\$4.48	\$4.28 \$24.11
	26W American Revolution Decorative (100W Equivalent)	2,650	26	9	\$8.82	\$3.08	\$0.53 \$12.43
	44W American Revolution Decorative (150W Equivalent)	4,460	44	15	\$8.74	\$3.05	\$0.90 \$12.69
	90W Acorn Decorative (150W Equivalent)	10,157	90	31	\$12.62	\$4.20	\$1.85 \$18.67
	60W Post Top Decorative (150W Equivalent)	7,026	60	21	\$22.37	\$7.08	\$1.25 \$30.70
	80W Flood (250W Equivalent)	12,500	80	27	\$12.24	\$3.85	\$1.61 \$17.70
	170W Flood (400W Equivalent)	24,000	170	58	\$12.24	\$3.85	\$3.46 \$19.55
	150W Flood (350W Equivalent)	20,686	150	52	\$12.24	\$3.85	\$3.09 \$19.18
	290 W Flood (1,000W Equivalent)	38,500	290	100	\$12.24	\$3.85	\$5.95 \$22.04
	82W Shoe Box (175W Equivalent)	20,500	23	276	\$10.79	\$3.66	\$3.09 \$17.54
	131W Shoe Box (250W Equivalent)	17,144	131	45	\$12.15	\$4.07	\$2.67 \$18.89

Charges for other Company-owned facilities:

1)	30' Wood Pole	\$5.46
2)	40' Wood Pole Std	\$12.15
3)	18' Fiberglass Round	\$11.31
4)	13' Decorative Concrete	\$16.02
5)	20' Decorative Concrete	\$18.59
6)	35' Concrete Square	\$17.94
7)	10' Deco Base Aluminum	\$21.03
8)	30' Wood Pole Std	\$6.07

For the poles shown above that are served from an underground system, the Company will provide up to one hundred (100) feet of conductor to service each fixture. The Customer will provide and install the necessary conduit system to Company specifications.

Purchased Power Charges

Purchased power charges are adjusted annually by the Florida Public Service Commission. For current purchased power costs included in the tariff, see Sheet No. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

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7.014
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No.
Cancels Original Sheet No. 7.014

*RATE SCHEDULE LS
LIGHTING SERVICE*

Light Emitting Diode Lights

Type	Charges						
	Facility Type	Lamp Lumens	Size Watts	Est. KWH/Mo.	Facilities	Maintenance	Energy Total
	50W Outdoor Light (100W Equivalent)	5,682	50	17	\$7.997.46	\$2,532.36	\$1,081.01 \$11,6010.83
	50W Cobra Head (100W Equivalent)	5,944	50	17	\$10,099.42	\$3,142.93	\$1,081.01 \$14,3413.36
	82W Cobra Head (200W Equivalent)	9,600	82	28	\$9,458.82	\$2,952.75	\$1,781.67 \$14,4813.24
	130W Cobra Head (250W Equivalent)	14,571	130	45	\$9,448.78	\$2,942.74	\$2,872.67 \$15,2214.19
	210W Cobra Head (400W Equivalent)	28,653	210	72	\$16,4515.35	\$4,804.48	\$4,594.28 \$25,8424.11
	26W American Revolution Decorative (100W Equivalent)	2,650	26	9	\$9,458.82	\$3,303.08	\$0,570.53 \$13,3212.43
	44W American Revolution Decorative (150W Equivalent)	4,460	44	15	\$9,368.74	\$3,273.05	\$0,960.90 \$13,5912.69
	90W Acorn Decorative (150W Equivalent)	10,157	90	31	\$13,5312.62	\$4,504.20	\$1,981.85 \$20,0118.67
	60W Post Top Decorative (150W Equivalent)	7,026	60	21	\$23,9722.37	\$7,597.08	\$1,341.25 \$32,9030.70
	80W Flood (250W Equivalent)	12,500	80	27	\$13,1112.24	\$4,133.85	\$1,721.61 \$18,9617.70
	170W Flood (400W Equivalent)	24,000	170	58	\$13,1112.24	\$4,133.85	\$3,703.46 \$20,9419.595
	150W Flood (350W Equivalent)	20,686	150	52	\$13,1112.24	\$4,133.85	\$3,343.09 \$20,5519.18
	290 W Flood (1,000W Equivalent)	38,500	290	100	\$13,1112.24	\$4,133.85	\$6,375.95 \$23,6422.04
	82W Shoe Box (175W Equivalent)	20,500	23	276	\$11,5610.79	\$3,923.66	\$3,343.09 \$18,7917.54
	131W Shoe Box (250W Equivalent)	17,144	131	45	\$13,0212.15	\$4,364.07	\$2,872.67 \$20,2518.89

Charges for other Company-owned facilities:

- 1) 30' Wood Pole \$5,855.46
- 2) 40' Wood Pole Std \$13,0212.15
- 3) 18' Fiberglass Round \$12,1211.31
- 4) 13' Decorative Concrete \$17,1716.02
- 5) 20' Decorative Concrete \$19,9218.59
- 6) 35' Concrete Square \$19,2217.94
- 7) 10' Deco Base Aluminum \$22,5321.03
- 8) 30' Wood Pole Std \$6,546.07

For the poles shown above that are served from an underground system, the Company will provide up to one hundred (100) feet of conductor to service each fixture. The Customer will provide and install the necessary conduit system to Company specifications.

Purchased Power Charges

Purchased power charges are adjusted annually by the Florida Public Service Commission. For current purchased power costs included in the tariff, see Sheet No. 7.021 & 7.022.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

ORDER NO. PSC-2025-0287-AS-EI
DOCKET NO. 20240099-EI
PAGE 42

Attachment A
Page 35 of 36

Florida Public Utilities Company
F.P.S.C. Electric Tariff
Original Volume No. II

First Revised Sheet No. 7.016
Cancels Original Sheet No. 7.016

*RATE SCHEDULE OSL
MERCURY VAPOR LIGHTING SERVICE
(Closed To New Installations)*

Availability

Available within the territory served by the Company in Calhoun, Jackson and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to any Customer for mercury vapor lighting service.

Character of Service

Lighting service from dusk to dawn as described herein.

Limitations of Service

Service is limited to lighting by mercury vapor lamps of 7,000 or 20,000 initial level of lumens mounted on wood poles, as described herein.

Monthly Rate

When lighting fixtures are mounted on existing poles and served directly from existing overhead secondary distribution lines:

Lamp Size	KWH/Mo.	Facilities	Maintenance*	Energy	Total
<u>Lumens</u>	<u>Estimate</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>
7,000	72	\$1.57	\$1.40	\$4.19	\$7.16
20,000	154	\$1.73	\$1.50	\$9.01	\$12.24

For concrete or fiberglass poles and/or underground conductors, etcetera, the Customer shall pay a lump sum amount equal to the estimated differential cost between the special system and the equivalent overhead-wood pole system.

Purchased Power

Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The above rates times the number of lamps connected.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

ORDER NO. PSC-2025-0287-AS-EI
DOCKET NO. 20240099-EI
PAGE 43

Attachment A
Page 36 of 36

Florida Public Utilities Company
7.016

First Revised Sheet No.
Cancels Original Sheet No. 7.016

F.P.S.C. Electric Tariff
Original Volume No. II

*RATE SCHEDULE OSL
MERCURY VAPOR LIGHTING SERVICE
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Lamp Size	KWH/Mo.	Facilities	Maintenance*	Energy	Total
<u>Lumens</u>	<u>Estimate</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>	<u>Charge</u>
7,000	72	~~\$1,691.57~~	~~\$1,541.40~~	<u>\$4,494.19</u>	<u>\$7,697.16</u>
20,000	154	~~\$1,861.73~~	~~\$1,601.50~~	<u>\$9,659.01</u>	<u>\$13,112.24</u>

For concrete or fiberglass poles and/or underground conductors, etcetera, the Customer shall pay a lump sum amount equal to the estimated differential cost between the special system and the equivalent overhead-wood pole system.

Purchased Power

Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

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Terms of Payment

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Issued by: Jeffrey Sylvester, Chief Operating Officer
Florida Public Utilities

Effective: March 20, 2025

BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
OF
NICHOLAS A. CROWLEY
SENIOR ECONOMIST
CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

ON BEHALF OF
ALPENA POWER COMPANY

December 11, 2023

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Alpena Power Company
Case No. U-21488
Witness: Nicholas Crowley
Page 1 of 7

1 **1. INTRODUCTION**

2 **Q1. Mr. Crowley, please state your full name and business address.**

3 A.1 My name is Mr. Nicholas A. Crowley. My business address is 800 University Bay
4 Drive, Suite 400, Madison, Wisconsin, 53705.

5 **Q2. Mr. Crowley, by whom are you employed and in what capacity?**

6 A.2 I am a Senior Economist with Christensen Associates.

7 **Q3. Would you please summarize your educational background and business**
8 **experience?**

9 A.3 I have a Bachelor of Science in economics, as well as a Master of Science in
10 economics from the University of Wisconsin-Madison. I began working at
11 Christensen Associates in 2016. Prior to joining this firm, I was an Economist in the
12 Department of Pipeline Regulation at the Federal Energy Regulatory Commission
13 (“FERC”), where I assisted with energy industry benchmarking, the incentive
14 regulation of oil pipelines,¹ and the review and evaluation of natural gas pipeline rate
15 cases. In these roles, I have worked extensively with utility data and financial
16 accounting data for the development of cost of capital studies, as well as cost-of-
17 service, marginal cost, rate design, and productivity analysis. My curriculum vitae is
18 attached as Attachment A.

¹ Five-Year Review of the Oil Pipeline Index. Issued: December 17, 2015. 153 FERC ¶ 61,312.

Alpena Power Company
Case No. U-21488
Witness: Nicholas Crowley
Page 2 of 5

1 **Q4. Mr. Crowley, have you previously testified before the Michigan Public Service**
2 **Commission or other state regulatory commission?**

3 A.4 I have not testified before the Michigan Public Service Commission (“Michigan
4 PSC”), but I have testified on behalf of utilities in both the United States and Canada.
5 Most recently, I testified on behalf of Fitchburg Gas & Electric for their rate
6 application in Massachusetts.² I have also testified with Dr. Mark Meitzen on behalf of
7 NSTAR Electric Company d/b/a Eversource Energy and on behalf of Boston Gas
8 Company and the former Colonial Gas Company each d/b/a National Grid.³ I have
9 also testified in Alberta, Canada, on issues related to PBR on behalf of EPCOR
10 Distribution and Transmission, Inc.⁴ In addition, I have filed reports on cost of capital
11 that were filed in the Caribbean and in the state of Wisconsin.⁵ I have also filed reports
12 related to marginal costs before regulatory authorities in Canada.⁶

13 **Q5. What is the purpose of your testimony?**

14 A.5 I am submitting an analysis of Alpena Power Company’s (“Alpena Power”) cost of
15 capital before the Michigan PSC as a component of Alpena Power’s rate application
16 under docket U-21488. My analysis covers an estimation of Alpena Power’s cost of

² Direct Testimony of Nicholas A. Crowley, D.P.U. 23-80 and D.P.U. 23-81, August 17, 2023.

³ Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

⁴ Determination of the Third-Generation X Factor for the AUC Price Cap Plan, Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, January 20, 2023.

⁵ For Grand Bahama Power Company, in 2018 and again in 2021. Also, for St. Croix Gas Company, located in western Wisconsin, in 2019.

⁶ *Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029*, Prepared for Newfoundland and Labrador Hydro, November 15, 2018.

Alpena Power Company
Case No. U-21488
Witness: Nicholas Crowley
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equity, as well as a recommendation for Alpena Power's overall weighted average cost of capital.

Q6. Please describe the workpapers and exhibits contained within your testimony.

A.6 In addition to this document, my testimony consists of a full cost of capital report, submitted as a workpaper labeled Alpena COC and ROR Report. I am sponsoring Exhibits A-4 and A-14. Exhibit A-4 covers the Weighted Average Cost of Capital for the Historical Year ended April 30, 2024. Exhibit A-14 covers the Weighted Average Cost of Capital for the Projected 12 Month period ending June 30, 2025.

2. SUMMARY

Q7. What is the recommended cost rate to be applied to Alpena Power's long-term debt?

A.7 The cost of debt component of the Company's capital structure consists primarily of long-term debt issued in the form of Energy Thrift Notes at a cost of 4.57%. As well, a small amount of short-term debt is expected to be issued at a cost of 6.18%. These costs are derived from the 13-month average forecast for year ending June 2025. This cost of debt is a component of the company's overall weighted average cost of capital. In particular, the proportion of long-term debt in Alpena Power's capital structure is 41.69%, while the proportion of short-term debt is 3.08%.

Q8. What is the estimated cost of equity for Alpena Power?

A.8 The estimated COE for Alpena Power is within the range of 10.50 – 13.31%, with a mid-point of 11.91% resulting in a corresponding recommendation of 11.91% for the

Alpena Power Company
Case No. U-21488
Witness: Nicholas Crowley
Page 4 of 5

1 Company's allowed return on equity. Common stock equity constitutes 43.61% of the
2 Company's capital structure, as determined by the Company's 13-month forecast for
3 the year ending June 2025. In its deliberation of the of cost of capital, we recommend
4 that the MPSC endorse this COE estimate and set the allowed rate of return on
5 common equity for Alpena Power accordingly. Note that Alpena Power does not have
6 any preferred shares outstanding and does not anticipate issuing any such shares
7 during the test period.

8 **Q9. Please provide a summary of your findings.**

9 The analysis contained in Exhibit A-14 utilizes cost of capital methods common to
10 capital valuation and financial economics to estimate the return on equity required for
11 Alpena to continue to serve Alpena County, Michigan with reliable power. This
12 overall cost of equity estimate is obtained by applying four cost of equity methods
13 including capital asset pricing model ("CAPM"), discounted cash flow ("DCF"), risk
14 premia, and an assessment of realized market returns. These four methods are used to
15 assess the market experience of the three samples, including electric utilities, natural
16 gas distributors, and small low-risk non-utilities. The return on equity
17 recommendation that follows from this analysis is 11.91%. Aspects of the cost of
18 equity studies employ professional judgement, and the estimates contained in this
19 report may be conservative in several respects including size premia and inflation
20 expectations. Alpena Power's capital structure consist of contains debt, equity, and
21 deferred income taxes. The weighted average cost of capital, given Alpena's capital
22 structure and cost of debt, is 7.15%. The percentage of total capital and cost rates,
23 including the estimated cost of equity, are summarized in the following table:

Alpena Power Company
Case No. U-21488
Witness: Nicholas Crowley
Page 5 of 5

Summary of Overall Cost of Capital for Alpena Power

<u>Capital Type</u>	<u>Percent of Total Capital</u>	<u>Cost Rate</u>
Long-Term Debt	43.61%	4.57%
Common Stock Equity	41.69%	11.91%
Subtotal	85.30%	
Short-Term Debt	3.08%	6.18%
Deferred Income Taxes	11.62%	0.00%
Deferred ITC-Pre 1971	0.00%	0.00%
Deferred ITC-Post 1970	0.00%	8.16%
Weighted Average	100.00%	7.15%

Q10. Do you have additional remarks related to your cost of capital recommendation for Alpena Power?

A.9 Yes. I have produced a report with extensive analysis related to Alpena Power's cost of capital, which is supplied as a workpaper labeled Alpena COC and ROR Report. This report contains a full description of methods, assumptions, data, and citations that were used in determining the cost of capital for this rate application.

Q11. Does this conclude your testimony?

A.10 Yes it does.

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
ALPENA POWER COMPANY for authority to	)	
increase its rates for the sale of electricity.	)	Case No. U-21488
	)	

At the July 23, 2024 meeting of the Michigan Public Service Commission in Lansing,
Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Alessandra R. Carreon, Commissioner

ORDER APPROVING AMENDED SETTLEMENT AGREEMENT

On December 11, 2023, Alpena Power Company (Alpena) filed an application, with supporting testimony and exhibits, for approval of an annual revenue increase of \$3,959,588, based on a projected test year ending June 30, 2025. Alpena also requested: (1) authority to earn an overall return of 7.15%, including a rate of return of 11.91% on common equity; (2) new rates designed to continue to reflect no cross-subsidization between rate classes; (3) a revised power supply cost recovery (PSCR) base rate of 77.25 mills per kilowatt-hour (kWh); (4) approval, for accounting purposes, to defer and amortize the costs associated with this proceeding over a three-year period, and to record deferred taxes related thereto; (5) continuation of its Electric Vehicle Charging Pilot Program until December 31, 2028; (6) revised time-of-use periods, on-peak price ratios, and designated holidays in the following tariffs: Large Power, Large Industrial, Residential Plug-In Electric Vehicle, General Service Plug-In Electric Vehicle, and Efficient Electric Heat;

and (7) inflationary increases to its Special Charges specified in its Terms and Conditions of Service.

A prehearing conference was held on January 11, 2024, before Administrative Law Judge Lesley C. Fairrow (ALJ) at which, the ALJ recognized the intervention of the Michigan Department of Attorney General. Alpena and the Commission Staff also participated in the proceeding. Subsequently, the parties submitted an amended settlement agreement resolving all issues in the case.

According to key provisions of the amended settlement agreement, the parties agree that Alpena's tariffs should be revised to reflect an annual revenue increase of approximately \$2,500,000 as reflected on Attachment 1 to the amended settlement agreement, effective for service upon the date of the Commission's order approving the amended settlement agreement. The agreed upon rates are cost-based and include an authorized rate of return on common equity of 9.85% and an overall rate of return of 6.29%, as provided in the revised tariff sheets set forth in Attachment 2 to the amended settlement agreement. Attachment 2 to the amended settlement agreement also reflects miscellaneous tariff changes agreed upon by the parties. The parties further agree there shall be a subsequent rate increase moratorium with no new general rate increase prior to January 1, 2026; however, the parties agree that Alpena shall file a depreciation case, separate from a general rate case, by December 22, 2026. Additionally, the parties agree that the revised rates reflect a new PSCR base of 77.25 mills per kWh.

The Commission has reviewed the amended settlement agreement and finds that the public interest is adequately represented by the parties who entered into the amended settlement agreement. The Commission further finds that the amended settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The amended settlement agreement, attached as Exhibit A, is approved.

B. The revised rates and tariffs set forth in Attachment 2 to the amended settlement agreement are approved and shall become effective as of the date of this order.

C. Within 30 days of the issuance of this order, Alpena Power Company shall file with the Commission tariff sheets essentially the same as those set forth in Attachment 2 to the amended settlement agreement. After the tariff sheets have been reviewed and accepted by the Commission Staff for inclusion in the company's tariff book, Alpena Power Company shall promptly file the final tariff sheets in this docket and serve all parties.

D. Alpena Power Company shall file a depreciation case that is separate from a general rate case by December 22, 2026.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel.

Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General – Public Service Division at hugheys@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Alessandra R. Carreon, Commissioner

By its action of July 23, 2024.

Lisa Felice, Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
ALPENA POWER COMPANY	)	
for authority to increase its rates for the	)	Case No. U-21488
sale of electricity.	)	
_____	)	

AMENDED SETTLEMENT AGREEMENT

Alpena Power Company (“Alpena”), by and through its attorney, Timothy M. Gulden; the Michigan Public Service Commission Staff (“Staff”), by and through its attorneys, Michael J. Orris and Anna B. Stirling; and the Attorney General of Michigan (“the Attorney General”), by and through her attorney, Michael E. Moody, hereby present this Amended Settlement Agreement in resolution of the above matter. This Amended Settlement Agreement replaces the Settlement Agreement that was previously filed with the Michigan Public Service Commission on June 20, 2024.

1. On December 11, 2023, Alpena filed its application with supporting testimony and exhibits, for approval of an annual increase in jurisdictional revenue of \$3,959,558. In addition, Alpena’s application and supporting testimony sought:

- a) authority to earn an overall return of 7.15%, including a rate of return of 11.91%

SETTLEMENT AGREEMENT
U-21488

on common equity;

- b) new rates designed to continue to reflect no cross-subsidization between rate classes;
- c) a revised PSCR base rate of 77.25 mills;
- d) approval, for accounting purposes, to defer and amortize the costs associated with this proceeding over a three-year period, and to record deferred taxes related thereto;
- e) continuation of its Electric Vehicle Charging Pilot Program until December 31, 2028;
- f) revised time of use periods, on-peak price ratios, and designated holidays in the following tariffs: Large Power, Large Industrial, Residential Plug-In Electric Vehicle, General Service Plug-In Electric Vehicle, and Efficient Electric Heat; and
- g) inflationary increases to its Special Charges specified in its Terms and Conditions of Service.

2. On December 13, 2023, the Commission issued its Notice of Hearing scheduling a pre-hearing conference for January 11, 2024, before Administrative Law Judge Lesley C. Fairrow.

3. In accordance with the directives of the Commission, Alpena gave notice of the prehearing conference throughout its service territory. Alpena electronically filed its proof of service and affidavit of publication of the Notice of Hearing with the Commission on January 4, 2024.

SETTLEMENT AGREEMENT
U-21488

4. At the January 11, 2024, prehearing conference, it was established that Alpena timely served and published the Notice of Hearing. In addition, a case schedule was established, and intervenor status was granted by Judge Fairrow to Attorney General Dana Nessel.

5. On March 25, 2024, Alpena, Staff, and the Attorney General conducted settlement discussions that led to the agreements incorporated in this Amended Settlement Agreement.

6. The parties agree that this Amended Settlement Agreement will aid in the expeditious conclusion of this matter and will minimize the expense of this proceeding by both Alpena and the Commission.

7. This Amended Settlement Agreement resolves this case, and all provisions of this agreement are dependent upon all other provisions.

8. Alpena, Staff, and the Attorney General agree as follows:

- A. Alpena shall be authorized to revise its tariffs to reflect an annual revenue increase of approximately \$2,500,000, effective upon the Commission's order approving this Settlement Agreement. There shall be a subsequent rate increase moratorium with no new general rate increase prior to January 1, 2026.
- B. On a class-by-class basis, the tariff sheets in Attachment 2 implement percentage rate increases as set forth in Attachment 1 hereto.
- C. The agreed upon rates reflect an authorized rate of return on common equity of 9.85% and an overall rate of return of 6.29%.
- D. The revised rates reflect a new Power Supply Cost Recovery

SETTLEMENT AGREEMENT
U-21488

("PSCR") base of 77.25 mills per kWh at the generation level.

- E. The revised rates reflect a new loss factor of 7.58%.
- F. Alpena shall revise its Customer Charges as follows: Residential \$5.25, General Service \$7.50, Standard Power \$35, Large Power \$125, Large Industrial \$425.
- G. Alpena shall allocate costs associated with its Low-Income Assistance Service Provision among all jurisdictional customer classes.
- H. Alpena shall modify its DG Tariff to be consistent with the provisions of 2023 PA 235, as directed by the Commission.
- I. Alpena shall modify its Special Charges as set forth in Attachment 2.
- J. Alpena shall file a depreciation case, separate from a general rate case, by December 22, 2026.
- K. Alpena shall be authorized to extend its Electrical Vehicle Charging Pilot Program approved in the July 27, 2022, order in Case No. U-21234 until December 31, 2028.
- L. Alpena shall be authorized to revise its time of use periods and on-peak to off-peak price ratios in the following tariffs: Large Power, Large Industrial, Residential Plug-In Electric Vehicle, General Service Plug-In Electric Vehicle, and Efficient Electric Heat as set forth in Attachment 2.
- M. Alpena shall be authorized to defer and amortize the cost, and related deferred taxes, of this rate case over a three-year period to begin the same date that the rate relief requested herein is effective.
- N. The total increase to the Street and Highway Lighting

SETTLEMENT AGREEMENT
U-21488

Service Tariff will be implemented over a five-year period. The annual shortfall will be distributed to the General Service Tariff. The implementation period will be revisited if the Company files a general rate case before the expiration of the five-year period.

- O. The provisions of this Settlement Agreement shall take effect upon the Commission's order approving this Settlement Agreement.

9. This Amended Settlement Agreement will become binding upon the parties only if the Commission accepts and approves it without modification. If the Commission does not approve this Amended Settlement Agreement without modification, it shall be withdrawn and shall not constitute any part of the record in the proceeding or be used for any purpose whatsoever.

10. This Amended Settlement Agreement has been made for the sole and express purpose of reaching a compromise among the positions of the signatories without prejudice to their rights to take new and different positions in other proceedings. All offers of settlement and discussions relating to this Amended Settlement Agreement shall be considered privileged under MRE 408. If the Commission approves this Amended Settlement Agreement without modification, the parties shall make no reference to or use this Amended Settlement Agreement or the order approving it as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceedings; provided, however, such references or use may be made to enforce this Amended Settlement Agreement and order.

SETTLEMENT AGREEMENT
U-21488

11. All parties waive Section 81 of the Administrative Procedures Act of 1969, as amended, MCL 24.281.

12. The parties agree that approval of this Amended Settlement Agreement by the Commission would be reasonable and in the public interest; this Amended Settlement Agreement is intended for final disposition of this proceeding; and the parties join in respectfully requesting the Commission to grant prompt approval of the agreement.

ALPENA POWER COMPANY

**Timothy
M. Gulden**

Digitally signed by Timothy M. Gulden
DN: cn=Timothy M. Gulden, o=Bauer,
Florip & Wojda PLC, ou,
email=tmgulden@bfwlawfirm.com,
c=US
Date: 2024.07.03 09:47:11 -04'00'

By: Timothy M. Gulden (P41232)
Its: Attorney
Bauer, Florip & Wojda PLC
109 E. Chisholm St.
Alpena, MI 49707
(989) 356-3444

MICHIGAN PUBLIC SERVICE

COMMISSION

Michael J. Orris



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By: Michael J. Orris (P51232)
Anna B. Stirling (P84919)
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
(517) 284-8140

MICHIGAN ATTORNEY GENERAL

**Michael E.
Moody**

Digitally signed by Michael
E. Moody
Date: 2024.07.03 08:56:11
-04'00'

By: Michael E. Moody (P51985)
Assistant Attorney General
Special Litigation Division
6th Floor, G. Mennen Williams Bldg.
525 W. Ottawa Street
P.O. Box 30755
Lansing, MI 48909
(517) 335-7627

SETTLEMENT AGREEMENT
U-21488

Attachment 1
Case No. U-21488

ALPENA POWER COMPANY

Present and Proposed Revenues by Rate Schedules for Settlement Agreement

Line No.	(a) Description	(b) Total Present Revenue	(c) Total Proposed Revenue	2024		2025		2026		2027		2028	
				(d) Change	(e) Percent Increase	(f) Change	(g) Percent Increase	(h) Change	(i) Percent Increase	(j) Change	(k) Percent Increase	(l) Change	(m) Percent Increase
1	Residential	14,225,600	15,900,369	1,674,769	11.77%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
2	General Service	4,556,900	5,056,095	499,195	10.95%	-3,742	-0.07%	-3,742	-0.07%	-3,454	-0.07%	-3,742	-0.07%
4	Standard Power	5,722,700	6,361,234	638,534	11.16%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
5	Large Power	2,605,100	2,606,978	1,878	0.07%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
6	Large Industrial	4,322,400	3,931,401	-390,999	-9.05%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
7	Outdoor Protective Lights	243,900	316,165	72,265	29.63%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
8	Street & Highway Lights	21,600	25,293	3,693	17.10%	3,706	14.65%	3,698	12.75%	3,696	11.30%	3,704	10.18%
9	Misc Operating Revenue	229,900	229,900	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
10	Total Jurisdictional Revenues	31,928,100	34,427,435	2,499,335	7.83%	-36	0.00%	-44	0.00%	242	0.00%	-38	0.00%
11	Special Contract	5,500,900	5,500,900	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
12	Total Revenues	37,429,000	39,928,335	2,499,335	6.68%	-36	0.00%	-44	0.00%	242	0.00%	-38	0.00%

Attachment 2

Case No. U-21488

ALPENA POWER COMPANY

Tariff Sheets

For Settlement Agreement

ALPENA POWER COMPANY

**RATE BOOK
FOR
ELECTRIC SERVICE**

These Standard Rules and Regulations and Rate Schedules contained herein have been adopted by the Company to govern its relations with customers and have been approved by the Michigan Public Service Commission as an integral part of its Rate Book for the delivery of Electric Service.

Copies of the Company's Rate Book for Electric Service are available on Alpena Power Company's website at the following website address:

<https://www.alpenapower.com/wp-content/uploads/2023/09/alpena9cur-3.pdf>

or at the Michigan Public Service Commission's website at the following website address:

<https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/alpena/alpena9cur.pdf?rev=9793904964f944a498135e23584451be&hash=5E928EA7FEB72CAE023174D66CDCA273>

Territory

This Rate Book applies to the entire territory served by Alpena Power Company. All rates contained in these schedules are standard rates and have general application.

**THIS RATE BOOK SUPERSEDES AND CANCELS RATE BOOK
M.P.S.C. No. 8**

Issued , by
Kenneth A. Dragiewicz, President
Alpena, MI 49707

M.P.S.C. No. 9
Alpena Power Company
(Revise links)

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M.P.S.C. No. 9
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SECTION B

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SECTION B

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SECTION B

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R 460.974	Interconnection metering and communications.
R 460.976	Post commissioning remedy.
R 460.978	Disconnection.
R 460.980	Capacity of the DER.
R 460.982	Modification of the interconnection application.
R 460.984	Modifications to the DER.
R 460.986	Insurance.
R 460.988	Easements and rights-of-way.
R 460.990	Interconnection penalties.
R 460.991	Business day exclusions.
R 460.992	Electric utility annual reports.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001	Application process.
R 460.1004	Legacy net metering program application and fees.
R 460.1006	Distributed generation program application and fees.
R 460.1008	Legacy net metering program and distributed generation program size.
R 460.1010	Generation and legacy net metering program or distributed generation program equipment.
R 460.1012	Meters for legacy net metering program.
R 460.1014	Meters for distributed generation program.
R 460.1016	Billing and credit for legacy net metering program customers taking service under true net metering.
R 460.1018	Billing and credit for legacy net metering program customers taking service under modified net metering.
R 460.1020	Billing and credit for distributed generation program customers.
R 460.1022	Renewable energy credits.
R 460.1024	Penalties.
R 460.1026	Legacy net metering grandfathering clause.

B9. SERVICE QUALITY AND RELIABILITY STANDARDS FOR ELECTRIC DISTRIBUTION SYSTEMS (R460.701 - R460.752)

<https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.701%20to%20R%20460.752.pdf>

PART 1. GENERAL PROVISIONS

R 460.701	Application of rules.
R 460.702	Definitions.
R 460.703	Revision of tariff provisions.

(continued on Sheet No. B-11.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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ADMINISTRATIVE RULES INDEX
(Continued from Sheet No. B-10.00)

**B9. SERVICE QUALITY AND RELIABILITY STANDARDS FOR ELECTRIC DISTRIBUTION SYSTEMS
(R460.701 - R460.752) (continued)**

<https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.701%20to%20R%20460.752.pdf>

PART 2. UNACCEPTABLE LEVELS OF PERFORMANCE

- R 460.721 Duty to plan to avoid unacceptable levels of performance.
- R 460.722 Unacceptable levels of performance during service interruptions.
- R 460.723 Wire down relief requests.
- R 460.724 Unacceptable service quality levels of performance.

PART 3. RECORDS AND REPORTS

- R 460.731 Deadline for filing annual reports.
- R 460.732 Annual report contents.
- R 460.733 Availability of records.
- R 460.734 Retention of records.

PART 4. FINANCIAL INCENTIVES AND CUSTOMER ACCOMMODATIONS

- R 460.741 Approval of incentives by the commission.
- R 460.742 Criteria for receipt of an incentive.
- R 460.743 Disqualification.
- R 460.744 Customer accommodation for failure to restore service after sustained interruption due to gray sky and catastrophic conditions.
- R 460.745 Customer accommodation for failure to restore service during normal conditions.
- R 460.746 Customer accommodation for repetitive interruptions.
- R 460.747 Multiple billing credits allowed.
- R 460.748 Effect in other proceedings.

PART 5. WAIVERS AND EXCEPTIONS

- R 460.751 Waivers and exceptions by electric utilities.
- R 460.752 Proceedings for waivers and exceptions.

ADDITIONAL ADMINISTRATIVE RULES

*Waivers may have been granted by the Commission to the Company for certain portions of the administrative rules below.

(continued on Sheet No. B-12.00)

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ADMINISTRATIVE RULES INDEX
(Continued from Sheet No. B-11.00)

- B10. **ADMINISTRATIVE HEARING RULES. PP. 1-18. AND PRACTICE AND PROCEDURE BEFORE THE COMMISSION PP. 45-68.**
<https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20792.10101%20to%20R%20792.11903.pdf>
- B11. **FILING PROCEDURES FOR ELECTRIC, WASTEWATER, STEAM, AND GAS UTILITIES (R 460.2011 - R 460.2031)**
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=832_10798_AdminCode.pdf
- B12. **RESIDENTIAL CONSERVATION PROGRAM STANDARDS (R 460.2401 - R 460-2414)-*Rescinded***
- B13. **PRESERVATION OF RECORDS OF ELECTRIC, GAS AND WATER UTILITIES (R460.2501 - R 460.2582)**
<https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.2501%20to%20R%20460.2582.pdf>
- B14. **UNIFORM SYSTEM OF ACCOUNTS FOR MAJOR AND NONMAJOR ELECTRIC UTILITIES (R 460.9001-460.9019)**
https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=841_10807_AdminCode.pdf
- B15. **RATE CASE FILING REQUIREMENTS FOR MAJOR ELECTRIC UTILITIES**
<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000009M7qdAAC>
- B16. **CODE OF CONDUCT (R 460.10101 - R 460.10113)**
<https://ars.apps.lara.state.mi.us/AdminCode/DownloadAdminCodeFile?FileName=R%20460.10101%20to%20R%20460.10113.pdf>

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M.P.S.C. No. 9
Alpena Power Company
(Reformatted Rate Book)

First-Revised Sheet No. C-13.00
Cancels Original Sheet No. C-13.00

TERMS AND CONDITIONS OF SERVICE
(Continued from Sheet No. C-12.00)

F. SPECIAL CHARGES - The Company will make such charges for reasonable special services as necessary to discourage abuse, and to prevent subsidy of such services by other customers.

1. AMOUNTS - The following schedule of amounts shall apply as applicable:

Charge for any Special Services at Customer's Request -	
During Regular Working Hours	\$40
Outside Regular Working Hours	\$80
Meter Reading Charge	\$17
Meter Test Charge	\$34
Meter Relocation Charge	Actual Cost
Reconnect Charge -	
Disconnected at Meter, During Regular Working Hours	\$34
Disconnected at Pole, During Regular Working Hours	\$40
Collection Charge When Nonpayment Disconnect Order is Written	\$17
Bad Check Handling Charge	\$25

2. DESCRIPTIONS - The above charges shall be applied in the following instances:

- a. CHARGES FOR ANY SPECIAL SERVICES AT CUSTOMER'S REQUEST** - Special services provided by the Company at the customer's request including, but not limited to, the following items:
- (1) When the Company temporarily disconnects service to facilitate repairs or other work on the customer's premises.
 - (2) When the Company reconnects service after repairs or other work on the customer's premises have been completed.
 - (3) When the Company makes a service call in response to an outage and it is determined that the outage was caused by a problem with the customer's facilities and not by the Company's facilities.

(continued on Sheet No. C-14.00)

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Alpena, MI 49707

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TERMS AND CONDITIONS OF SERVICE
(Continued from Sheet No. C-13.00)

- b. **METER READING CHARGE** - If the customer requests the Company to read his meter, the meter reading charge shall be paid in advance by the customer. If such read reveals that the Company had misread the meter, the meter reading charge shall be refunded and a billing adjustment made. This charge does not apply to meter reads made in conjunction with service connects or disconnects.
- c. **METER TEST CHARGE** - If the customer requests a test of his meter the meter test charge shall be paid in advance by the customer. If such test reveals the meter registration to be outside the accuracy limits prescribed by the Michigan Public Service Commission as specified in R 460.3301 through R 460.3306, the meter test charge shall be refunded and a billing adjustment made.
- d. **METER RELOCATION CHARGE** - Where service has been discontinued for reasons outlined in Sheet No. C-4.00, or as prescribed by the Michigan Public Service Commission as specified R 460.101 through R 460.169 (Residential Customers) or R 460.1601 through R 460.1640 a meter relocation charge, if applicable, and assessed in accordance with applicable rules shall be collected from the customer whose service was discontinued. The Company shall charge the customer for relocating the meter, based on the Company's actual cost.
- e. **RECONNECT CHARGE** - Where service has been discontinued for reasons outlined in Sheet No. C-4.00, or as prescribed by the Michigan Public Service Commission as specified in R 460.3301 through R 460.3306 a reconnect charge shall be collected from the customer as follows:
- (1) Reconnections during regular working hours where the service was disconnected at the meter shall be **\$34**.
 - (2) Reconnections during regular working hours where the service was disconnected at the point of contact with the Company's distribution system shall be **\$40**.
- f. **COLLECTION CHARGE WHEN NONPAYMENT DISCONNECT ORDER IS WRITTEN** - If the customer, about to be disconnected for nonpayment, elects to pay the energy arrears in full at the time of disconnection, the Company employee shall be authorized to accept payment. In addition to full payment of arrears, an additional **\$17** charge shall be paid by the customer if the Company has dispatched an employee to the customer's premises for the purpose of disconnecting the customer's service for nonpayment and the customer pays the full amount of the arrearage before the disconnection has occurred.

(continued on Sheet No. C-15.00)

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POWER SUPPLY COST RECOVERY CLAUSE

(Continued from Sheet No. D-1.00)

2. **PSCR FACTOR** - All rates for metered electric service shall include an amount up to the Power Supply Cost Recovery Factor (PSCR Factor) for the specified billing period as set below. The PSCR factor shall consist of an increase or decrease of **0.010758** mills per kWh for each full 0.01 mill per kWh increase or decrease in the projected annual power supply costs above or below a base cost of **77.25** mills per kWh, rounded to the nearest one-hundredth of a mill per kWh. The projected power supply costs per kWh shall equal the total projected annual net power cost divided by the projected annual net system energy requirements. Net system energy requirements shall be the sum of net generation and net purchased and interchange power.

Should the Company apply lesser factors than those shown below or if the factors are later revised pursuant to Commission orders or 1982 PA 304, the Company will notify the Commission if necessary and file a revision.

3. **MONTHLY REPORTS** - Not more than 45 days following the last day of each billing month in which a PSCR factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the PSCR factor and the allowance for cost of power included in the base rates established in the latest Commission Order for the Company, and the cost of power supply.
4. **ANNUAL RECONCILIATION** - All power supply revenues received by the Company, whether included in base rates or collected pursuant to a PSCR clause, shall be subject to annual reconciliation with the cost of power supply. Such annual reconciliations shall be conducted in accordance with the reconciliation procedures described in section 6j(12) to (18) of 1939 PA 3, as amended, including the provisions for refunds, additional charges, deferral and recovery, and shall include consideration by the Commission of the reasonableness and prudence of expenditures charged pursuant to any PSCR clause in existence during the period being reconciled.

(continued on Sheet No. D-3.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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M.P.S.C No. 9
Alpena Power Company
(To revise EWR surcharge)

Fifth-Revised Sheet No. D-4.91
Cancels Fourth Revised Sheet No. D-4.91

SURCHARGES
(continued from Sheet D-4.90)

Rate Schedule	<u>Energy Waste</u>	<u>Distribution</u>	<u>Total</u>
	<u>Reduction Surcharge</u>	<u>Charge</u>	
	<u>Effective <i>January 2024</i></u>	<u>for all Residential</u>	<u>Distribution Charge</u>
	<u>Bill Month</u>	<u>Rate Schedules</u>	
Residential	<i>\$0.00334/kWh</i>	<i>\$0.07926/kWh</i>	<i>\$0.08260/kWh</i>
Rate Schedule		<u>Customer Charge</u>	<u>Total Customer Charge</u>
General Service	<i>\$2.87/meter/month</i>	<i>\$7.50/month</i>	<i>\$10.37/month</i>
Standard Power	<i>\$45.29/meter/month</i>	<i>\$35.00/month</i>	<i>\$80.29/month</i>
Large Power (less than 13,200 volts)	<i>\$400.94/meter/month</i>	<i>\$125.00/month</i>	<i>\$525.94/month</i>
Large Power (13,200 volts or higher)	<i>\$400.94/meter/month</i>	<i>\$125.00/month</i>	<i>\$525.94/month</i>
Large Industrial (13,200 volts or lower)	<i>\$1,757.00/meter/month</i>	<i>\$425.00/month</i>	<i>\$2,182.00/month</i>
Large Industrial (higher than 13,200 volts)	<i>\$0.00/meter/month</i>	<i>\$425.00/month</i>	<i>\$425.00/month</i>
Large Industrial (>13,200 volts-Self Direct)	<i>\$230.92/meter/month</i>	<i>\$425.00/month</i>	<i>\$655.92/month</i>
Outdoor Protective Lighting (100 watt)	<i>\$0.27/light/month</i>	NA	<i>\$0.27/light/month</i>
Outdoor Protective Lighting (250 watt)	<i>\$0.45/light/month</i>	NA	<i>\$0.45/light/month</i>
Street & Highway Lighting	<i>\$0.25/light/month</i>	NA	<i>\$0.25/light/month</i>
Special Power Contracts (Self Direct)	<i>\$931.33/meter/month</i>	<i>\$600.00/month</i>	<i>\$1,531.33/month</i>

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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and after

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Michigan Public Service Commission
dated, in Case U-21488
and December 1, 2023 in Case U-21320

M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Eleventh-Revised Sheet No. D-5.00
Cancels Tenth-Revised Sheet No. D-5.00

RESIDENTIAL SERVICE

Availability:

Open to any customer desiring service for domestic and farm uses, which include only those purposes which are usual in individual private family dwellings, or separately metered apartments, and in the usual appurtenant buildings served through the residential meter. This rate is not available for commercial or industrial service, or for resale purposes.

Residences in conjunction with commercial or industrial enterprises; homes or dormitories for groups other than private family units; apartment buildings or multiple dwellings; and mobile homes in courts may take service on this rate only under the terms and conditions contained in the Company's Standard Rules and Regulations.

Service for single phase motors may be included under this rate, provided the individual capacity of such motors does not exceed 3 Hp, and the total capacity of such motors does not exceed 10 Hp, without the specific consent of the Company.

Nature of Service:

Alternating current, 60 hertz, single phase, 120/240 volts.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in (Sheet No E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Distribution Charges:

Customer Charge: \$ **5.25** per customer per month
Energy Charge: \$ **0.07926** per kWh for all kWh

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

(continued on Sheet No. D-6.00)

Issued, by
Kenneth A. Dragiewicz, President
Alpena, MI 49707

Effective for service rendered on and
after

Issued under authority of the
Michigan Public Service Commission
Dated
in Case No. U-21488

M.P.S.C. No. 9
Alpena Power Company
(To revise rate and RIA)

Fifth-Revised Sheet No. D-6.00
Cancels Fourth-Revised Sheet No. D-6.00

RESIDENTIAL SERVICE
(Continued from Sheet No. D-5.00)

Power Supply Charges:

Energy Charge: \$ *0.08536* per kWh for all kWh

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

Minimum Charge:

The Customer Charge and Renewable Energy Surcharge.

Income Assistance Service Provision (RIA):

When service is provided to a Residential Customer, where total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid
5. Supplemental Nutrition Assistance Program (SNAP)

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The Company reserves the right to verify eligibility. This provision is not available for alternate or seasonal homes. The customer must re-certify annually.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Distribution Charges: These charges are applicable to Full-Service Customers.

Income Assistance Credit: *\$(5.25)* per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

(continued on Sheet No. D-7.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Eleventh-Revised Sheet No. D-8.00
Cancels Tenth-Revised Sheet No. D-8.00

GENERAL SERVICE

Availability:

Open to any customer desiring lighting and incidental power service for any metered non-residential use, provided the load does not exceed 35 kW, measured on a 15-minute interval basis.

Nature of Service:

Alternating current, 60 hertz, single phase or three-phase, the particular voltage level in each case to be determined by the Company.

When the service is three-phase, 3-wire, lighting may be included provided the customer furnishes all transformation facilities required for such purpose, and so arranges the lighting circuits as to avoid excessive unbalance of the three-phase load. When service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 Hp, and the total single-phase motor capacity shall not exceed 10 Hp, without the specific consent of the Company.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in Section E, starting on (Sheet No. E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Distribution Charges:

Customer Charge: \$7.50 per customer per month

Energy Charge for service from XXXX X, 2024 to June 30, 2025: \$ 0.07439 per kWh for all kWh

Energy Charge for service from July 1, 2025 to June 30, 2026: \$ 0.07426 per kWh for all kWh

Energy Charge for service from July 1, 2026 to June 30, 2027: \$ 0.07413 per kWh for all kWh

Energy Charge for service from July 1, 2027 to June 30, 2028: \$ 0.07401 per kWh for all kWh

Energy Charge for service on and after July 1, 2028: \$ 0.07388 per kWh for all kWh

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

Power Supply Charges:

Energy Charge: \$ 0.08801 per kWh for all kWh

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

(continued on Sheet No. D-9.00)

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Alpena Power Company
(To Revise Expiration Date)

First-Revised Sheet No. D-10.10
Cancels Original Sheet No. D-10.10

GENERAL SERVICE
(Continued from Sheet No. D-10.00)

Demand Waiver for Electric Vehicle Chargers:

An Electric Vehicle Charging ("EVC") customer may take service under rate schedule General Service if the following criteria are met:

- (1) The maximum monthly demand must not exceed 150 kW, measured on a 15-minute interval basis.
- (2) The EVC installations taking service under rate schedule General Service pursuant to the terms of the demand waiver are required to establish a new, dedicated service for the EVC system.
- (3) EVC equipment load that is aggregated with other material non-EVC load at existing or new service locations are not permitted to participate in the Demand Waiver for Electric Vehicle Chargers.
- (4) EVC systems must be installed in locations where the existing distribution system can support the additional load without material modifications or incurrence of atypical interconnection costs, unless otherwise approved by the Company.
- (5) The Demand Waiver for Electric Vehicle Chargers will expire no later than ***December 31, 2028***.

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Eleventh-Revised Sheet No. D-11.00
Cancels Tenth-Revised Sheet No. D-11.00

STANDARD POWER SERVICE

Availability:

Open to any customer desiring secondary or primary voltage service where the annual highest actual demand, measured on a 15-minute interval basis, is at least 30 kW but less than 275 kW.

This rate is not available for street lighting service or for resale purposes.

Nature of Service:

Alternating current, 60 hertz, single phase or three-phase, the particular voltage level in each case to be determined by the Company.

When the service is three-phase, 3-wire, lighting may be included provided the customer furnishes all transformation facilities required for such purpose, and so arranges the lighting circuits as to avoid excessive unbalance of the three-phase load. When service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 Hp, and the total single-phase motor capacity shall not exceed 10 Hp, without the specific consent of the Company.

Where the Company elects to measure the service on the primary side of the transformers, 2% shall be deducted for billing purposes from the energy measurements thus made.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in Section E, starting on (Sheet No. E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Distribution Charges:

Customer Charge:

\$**35.00** per customer per month

Capacity Charge:

\$**15.922** per kW of billing demand

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

(continued on Sheet No. D-12.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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Commission Dated, December
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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Fifth-Revised Sheet No. D-12.00
Cancels Fourth-Revised Sheet No. D-12.00

STANDARD POWER SERVICE
(Continued from Sheet No. D-11.00)

Monthly Rate (Continued):

Power Supply Charges:

Energy Charge:

\$ **0.09219** per kWh for the first 300 kWh per kW of billing demand

\$ **0.08297** per kWh for the excess kWh

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

Billing Demand:

The billing demand shall be the maximum kilowatt demand, on a 15-minute interval basis, during the billing month, but not less than 50% of the highest billing demand of the preceding eleven months.

Billing demand determinations shall be rounded to the next highest full kilowatt.

Adjustment for Power Factor:

When the average power factor during the billing month is less than 80% lagging, the Company reserves the right to increase the capacity charge or charges, as applicable, for such billing month in the ratio that 80% bears to such average power factor. The Company shall determine the average power factor by test or by permanently installed measuring equipment.

Substation Ownership Credit:

When the customer furnishes and maintains complete substation equipment, including all transformers, switches, and other apparatus necessary to take service at primary voltage, 3% of the capacity charge or charges, as applicable, shall be deducted for billing purposes.

Minimum Charge:

The Customer Charge, Energy Waste Reduction Surcharge, Renewable Energy Surcharge and the Capacity Charge .

(continued on Sheet No. D-13.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Eleventh-Revised Sheet No. D-14.00
Cancels Tenth-Revised Sheet No. D-14.00

LARGE POWER SERVICE

Availability:

Available to any customer where the annual highest actual demand is at least 250 kW, measured on a 15-minute interval basis, but not more than 1,300 kW, measured on a 60-minute interval basis.

This rate is not available for resale purposes.

Nature of Service:

Alternating current, 60 hertz, three-phase, the particular voltage level in each case to be determined by the Company.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in Section E, starting on (Sheet No. E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Distribution Charges:

Customer Charge:

\$125.00 per month

Capacity Charge:

Maximum Demand Charge:

For service provided at 13,200 volts or higher nominal voltage:

\$ **9.919** per kW of maximum demand

For service provided at less than 13,200 volts nominal voltage:

\$ **12.099** per kW of maximum demand

Power Factor Charge:

\$ **0.284** per excess kVar

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

(continued on Sheet No. D-15.00)
Effective for service rendered on
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in Case No. U-21488

LARGE POWER SERVICE
(Continued from Sheet No. D-14.00)

Monthly Rate (Continued):

Power Supply Charges:

Energy Charge:

For service provided at 13,200 volts or higher nominal voltage:

\$ **0.09048** per kWh for all kWh consumed during the on-peak period

\$ **0.06751** per kWh for all kWh consumed during the off-peak period

For service provided at less than 13,200 volts nominal voltage:

\$ **0.09227** per kWh for all kWh consumed during the on-peak period

\$ **0.06886** per kWh for all kWh consumed during the off-peak period

On-Peak Billing Demand Charge:

For service provided at 13,200 volts or higher nominal voltage:

\$ 4.560 per kW of on-peak billing demand

For service provided at less than 13,200 volts nominal voltage:

\$ 4.651 per kW of on-peak billing demand

Power Factor Charge:

\$ **0.39** per excess kVar

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

On-Peak Billing Demand:

The on-peak billing demand shall be based on the highest on-peak demand created during the billing month, provided that no on-peak billing demand shall be less than 50% of the highest on-peak billing demand of the previous eleven billing months.

The on-peak demand shall be the highest 60-minute demand created during on-peak hours. Billing demand determinations shall be rounded to the next highest full kilowatt.

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(continued on Sheet No. D-16.00)

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in Case No. U- 21488

M.P.S.C. No. 9
Alpena Power Company
(To revise the schedule of On-Peak & Off-Peak Hours and Holidays)

First Revised Sheet No. D-16.00
Cancels Original Sheet No. D-16.00

LARGE POWER SERVICE
(Continued from Sheet No. D-15.00)

Monthly Rate (Continued):

Maximum Demand:

The maximum demand shall be the highest 60-minute demand created during the current month or previous eleven billing months.

Maximum demand determinations shall be rounded to the next highest full kilowatt.

Existing Customers:

Customers who switch to this rate from another rate shall have their demand history utilized in determining the minimum on-peak billing demand and maximum demand, until they have been on this rate for a full year.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

On-Peak Hours: **1:00 p.m. to 7:00 p.m.**

Off-Peak Hours: All other hours

Holidays Designated by the Company:

The following are designated as holidays by the Company:

New Year's Day

Labor Day

Memorial Day

Thanksgiving Day

Independence Day

Christmas Day

New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event that they fall on a Sunday, the Holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the Holiday remains on that Saturday.

Power Factor:

This rate requires the metering of kilovar-hours during the billing period. Each month an excess kilovar amount will be calculated using the following method:

- 1) Determine total lagging kilovar-hour usage by subtracting the metered leading kilovar-hours from the metered lagging kilovar-hours.
- 2) Determine the total lagging kilovar-hours that would have resulted in an average power factor of 90% for the billing month.
- 3) Subtract 2) from 1), divide the result by the actual number of hours in the billing month and round to the nearest whole number.

If the excess kilovar amount is positive a power factor charge will be added to the bill. If the excess kilovar amount is negative a power factor charge will be credited to the bill.

(continued on Sheet No. D-17.00)

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Seventh-Revised Sheet No. D-18.00
Cancels Sixth-Revised Sheet No. D-18.00

LARGE INDUSTRIAL SERVICE

Availability:

Available to any customer desiring primary voltage service where the capacity requirement is 1,250 kW or more. However, customers whose capacity requirements exceed 2,000 kW, or whose service requirements involve unusual Company investments, may be required to enter into a special contract. This rate is not available for resale purposes.

Nature of Service:

Alternating current, 60 hertz, three-phase, the particular voltage level in each case to be determined by the Company.

Term and Form of Contract:

All service under this rate shall require a written contract with a minimum term of one year.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in Section E, starting on (Sheet No. E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Distribution Charges:

Customer Charge:

\$ **425.00** per month

Capacity Charge:

Maximum Demand Charge:

For service provided at 34,500 volts nominal voltage:

\$ **3.956** per kW of maximum demand

For service provided at 13,800 volts nominal voltage:

\$ **3.956** per kW of maximum demand

For service provided at 13,200 or lower volts nominal voltage:

\$ **9.417** per kW of maximum demand

(continued on Sheet No. D-19.00)

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and after

Issued under authority of the
Michigan Public Service
Commission dated,
in Case No. U-21488

M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Eleventh-Revised Sheet No. D-19.00
Cancels Tenth-Revised Sheet No. D-19.00

LARGE INDUSTRIAL SERVICE
(Continued from Sheet No. D-18.00)

Monthly Rate (Continued):

Distribution Charges (Continued):

Power Factor Charge: \$ 0.284 per excess kVar

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

Power Supply Charges:

Capacity Charge:

On-Peak Billing Demand Charge:

For service provided at 34,500 volts nominal voltage:

\$ **12.431** per kW of on-peak billing demand

For service provided at 13,800 volts nominal voltage:

\$ **12.431** per kW of on-peak billing demand

For service provided at 13,200 volts or lower nominal voltage:

\$ **17.699** per kW of on-peak billing demand

Energy Charge:

For service provided at 34,500 volts nominal voltage:

\$ **0.06078** per kWh for all kWh consumed during the on-peak period

\$ **0.04536** per kWh for all kWh consumed during the off-peak period

For service provided at 13,800 volts nominal voltage:

\$ **0.06078** per kWh for all kWh consumed during the on-peak period

\$ **0.04536** per kWh for all kWh consumed during the off-peak period

For service provided at 13,200 volts or lower nominal voltage:

\$ **0.06323** per kWh for all kWh consumed during the on-peak period

\$ **0.04719** per kWh for all kWh consumed during the off-peak period

Power Factor Charge: \$0.39 per excess kVar

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

(continued on Sheet No. D-20.00)

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M.P.S.C. No. 9
Alpena Power Company
(To revise the On-Peak & Off-Peak hours & Holidays)

Second Revised Sheet No. D-20.00
Cancels First Revised Sheet No. D-20.00

LARGE INDUSTRIAL SERVICE
(Continued from Sheet No. D-19.00)

Monthly Rate (Continued):

Power Supply Charges (Continued):

On-Peak Billing Demand:

The on-peak billing demand shall be based on the highest on-peak demand created during the billing month, provided that no on-peak billing demand shall be less than 50% of the highest on-peak billing demand of the previous eleven billing months.

The on-peak demand shall be the highest 60-minute demand created during on-peak hours. Billing demand determinations shall be rounded to the next highest full kilowatt.

Maximum Demand:

The maximum demand shall be the highest 60-minute demand created during the current month or previous eleven billing months.

Maximum demand determinations shall be rounded to the next highest full kilowatt.

Existing Customers:

Customers who switch to this rate from another rate (including special contract rates) shall have their demand history utilized in determining the minimum on-peak billing demand and maximum demand, until they have been on this rate for a full year.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

On-Peak Hours: *1:00 p.m. to 7:00 p.m.*

Off-Peak Hours: All other hours

Holidays Designated by the Company:

The following are designated as holidays by the Company:

New Year's Day

Memorial Day

Independence Day

Labor Day

Thanksgiving Day

Christmas Day

New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event that they fall on a Sunday, the Holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the Holiday remains on that Saturday.

(continued on Sheet No. D-21.00)

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Kenneth A. Dragiewicz, President
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Effective for bills rendered on
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Issued under authority of the
Michigan Public Service Commission
dated, in Case No.
U-21488

M.P.S.C. No. 9
Alpena Power Company
(To revise off-peak hours)

First-Revised Sheet No. D-21.00
Cancels Original Sheet No. D-21.00

LARGE INDUSTRIAL SERVICE
(Continued from Sheet No. D-20.00)

Monthly Rate (Continued):

Extension of Off-Peak Hours:

The Customer may request that the off-peak billing hours be extended beyond **1:00 p.m.**, on any day of the year, for a time period of one to **six** additional hours. The first hour of any such extension shall be the hour ending at **2:00 p.m.** Such extension of the off-peak hours shall be continuous and may last for the entire on-peak period of that day.

The Customer shall request such extension at least 90 minutes before the beginning of the hour that would otherwise be an on-peak hour. The Customer's request will be automatically deemed approved by the Company unless the Company, at its sole discretion, specifically denies the request by informing the Customer of its denial at least 45 minutes prior to the beginning of the hour that would otherwise be an on-peak hour. All requests, approvals, or denials shall be transmitted in a mutually agreed upon method.

The total number of off-peak extended hours shall be limited to **36** hours in a calendar year. Once a Customer's request for extending off-peak hours is approved, either directly or indirectly, such request is irrevocable and the requested hours shall count against the **36** hour limit, regardless of the Customer's actual load during such hours.

During extended off-peak hours the Customer's energy charge shall be computed using the on-peak energy rate. When computing the monthly on-peak billing demand, demands set during extended off-peak hours will not be considered.

Power Factor:

This rate requires the metering of kilovar-hours during the billing period. Each month an excess kilovar amount will be calculated using the following method:

- 1) Determine total lagging kilovar-hour usage by subtracting the metered leading kilovar-hours from the metered lagging kilovar-hours.
- 2) Determine the total lagging kilovar-hours that would have resulted in an average power factor of 90% for the billing month.
- 3) Subtract 2) from 1), divide the result by the actual number of hours in the billing month and round to the nearest whole number.

If the excess kilovar amount is positive a power factor charge will be added to the bill. If the excess kilovar amount is negative a power factor charge will be credited to the bill .

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Alpena, MI 49707

(continued on Sheet No. D-22.00)
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M.P.S.C. No.
Alpena Power Company
(To revise rate)

Fifth-Revised Sheet No. D-22.00
Cancels Fourth-Revised Sheet No. D-22.00

LARGE INDUSTRIAL SERVICE
(Continued from Sheet No. D-21.00)

Monthly Rate (Continued):

Interruptible Load Discount:

A credit of **\$6.961** per kW of on-peak billing demand shall be applied to any Full Requirements Service customer who contracts in writing to permit the Company to curtail its entire load during a period of short-term power emergency.

If the customer wishes to allow a portion, but not all, of its load to be curtailed during a period of short-term power emergency, it can, subject to approval by the Company, nominate a firm load reservation that is no more than 25% of its maximum load. The customer's load above the firm load reservation will then be subject to curtailment. A credit of **\$ 6.683** per kW of that portion of the on-peak billing demand which is in excess of the customer's firm load reservation shall be applied to any customer who contracts in writing to permit the Company to curtail a portion of its load during a period of short-term power emergency.

The customer shall be provided, whenever possible, notice in advance of probable interruption and the estimated duration of the interruption. Customers who do not interrupt within one hour following notice of an interruption order shall be billed at the cost of replacement energy plus \$0.01 per kWh during the time of the interruption, but not less than \$0.07 per kWh. Additionally the customer shall be billed at the rate of \$50 per kW for the highest 60-minute kW demand created during the interruption period for all usage above the customer's firm demand, in addition to the prescribed monthly rate.

Once the customer has contracted in writing to permit all or a portion of its load to be curtailed it must provide 24 months written notice of its desire to revert to firm service or to increase the firm load reservation. The Company may waive all or a portion of this notice requirement.

Billing Determinants:

All billing determinants shall be based upon recorded meter information.

Minimum Charge:

The Capacity Charge plus the Customer Charge, ***Energy Waste Reduction Surcharge***, and Renewable Energy Surcharge.

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Alpena, MI 49707

(continued on Sheet No. D-23.00)
Effective for service rendered on
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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Sixth-Revised Sheet No. D-27.00
Cancels Fifth-Revised Sheet No. D-27.00

EFFICIENT ELECTRIC HEAT SERVICE (EEHS)

Availability:

Open to any customer eligible for the Residential or General Service Rates who uses Geothermal or Heat Pump Systems and take service from the Company. This rate is not available for resale purposes. Total load is not to exceed 35kW, measured on a 15-minute interval basis. Customers under this tariff may not operate distributed generation resources or participate in the Company's Net Metering Program.

The customer can select from two billing options, both of which include metering that is capable of separately identifying EEHS usage. Customer-specific information will be held confidential and the data presented in any analysis will protect the identity of the individual customer.

Nature of Service:

Alternating current, 60 hertz, single phase or three-phase, the particular voltage level in each case to be determined by the Company.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in (Sheet No E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Option 1 - Separately Metered EEHS Time-of-Day: An additional multi-register meter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure EEHS kWh usage from all other kWh usage at the residence. EEHS kWh usage will be billed at the following Monthly Rates and all other kWh usage will be billed separately at applicable Rates.

Distribution Charges for Residential Service Customer:

Customer Charge: \$ **5.25** per customer per month
Energy Charge: \$ **0.07926** per kWh for all kWh consumed

(continued on Sheet No. D-28.00)

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Alpena, MI 49707

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EFFICIENT ELECTRIC HEAT (EEHS)
(Continued from Sheet No. D-27.00)

Distribution Charges for General Service Customer:

Customer Charge: \$ *7.50* per customer per month

Energy Charge for service from XXXX X, 2024 to June 30, 2025: \$ 0.07439 per kWh for all

kWh Energy Charge for service from July 1, 2025 to June 30, 2026: \$ 0.07426 per kWh for all

kWh Energy Charge for service from July 1, 2026 to June 30, 2027: \$ 0.07413 per kWh for all

kWh Energy Charge for service from July 1, 2027 to June 30, 2028: \$ 0.07401 per kWh for all

*kWh Energy Charge for service on and after July 1, 2028: \$ 0.07388 per kWh for all
kWh*

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

Power Supply Charges for Residential Service Customer:

Energy Charge: \$ *0.08536* per kWh for all kWh consumed during the on-peak period

\$ *0.04423* per kWh for all kWh consumed during the off-peak period

Power Supply Charges for General Service Customer:

Energy Charge: \$ *0.08801* per kWh for all kWh consumed during the on-peak period

\$ *0.04560* per kWh for all kWh consumed during the off-peak period

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on
Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements
Service from the Company.

Minimum Charge:

The Customer Charge and Renewable Energy Surcharge.

Option 2 - Sub-metered EEHS Time-of-Day: A standard meter will measure total kWh usage and an
additional submeter capable of measuring electrical energy consumption during on-peak and
off-peak billing periods will be installed to separately measure EEHS kWh usage only. Total
usage will be billed at Standard Monthly Rates. A second meter charge will apply and for all off-
peak EEHS kWh usage additional credits will apply as follows:

Distribution Charges:

Second Meter Charge: \$3.00 per customer per month

(continued on Sheet No. D-29.00)

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EFFICIENT ELECTRIC HEAT (EEHS)
(Continued from Sheet No. D-28.00)

Power Supply Charges

Power Supply Charge Credit for Residential Customers: *\$(0.04113)* per kWh for all kWh consumed during the off-peak period.

Power Supply Charge Credit for General Service Customers: *\$(0.04241)* per kWh for all kWh consumed during the off-peak period.

Minimum Charge:

The Customer Charge, Renewable Energy Surcharge and a second meter charge shall apply.

Customer Switching Service Charge:

\$5.00 each time a customer switches between Generation Service providers. This includes switches from one AES to another, from the Company to an AES, and from an AES to the Company. The customer may switch Generation Service providers at the end of any billing month provided the notice requirements of (Sheet No. E-6.00, Section 2.4) are met. The Customer Switching Service Charge shall not be applied for the first switch of each calendar year or at a time the customer returns to its immediately previous Generation Service provider because the customer was Slammed by an AES.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the unpaid balance, net of taxes, shall be assessed to any bill which is delinquent. The late payment charge shall not apply to customers participating in the Winter Protection Plan.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

On-Peak Hours: *1:00 p.m. to 7:00 p.m.*

Off-Peak Hours: All other hours

Holidays Designated by the Company:

The following are designated as holidays by the Company:

New Year's Day

Labor Day

Memorial Day

Thanksgiving Day

Independence Day

Christmas Day

New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event that they fall on a Sunday, the Holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the Holiday remains on that Saturday.

Rules and Regulations:

Service under this rate is governed by the Company's Standard Rules and Regulations. The charges under this rate are subject to the General Terms and Conditions of Rate Schedules (Sheet No. D-1.00 through Sheet No. D-4.00).

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Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Twelfth-Revised Sheet No. D-30.00
Cancels Eleventh-Revised Sheet No. D-30.00

OUTDOOR PROTECTIVE LIGHTING SERVICE

Availability:

Customers desiring controlled service for outdoor protective lighting on premises where the customer is presently taking service under a standard rate schedule.

Hours of Service:

Dusk to dawn service controlled by photo-sensitive devices which provide service every night and all night for approximately 4,200 hours per year.

Nature of Service:

New Service requests will consist of a light emitting diode (LED) fixture appropriately mounted. Customers that have existing high-pressure sodium (HPS) lights in place are able to continue to use those lights until such time as the fixture is damaged or the company determines it needs to be replaced. At that time, it will be replaced with an LED fixture. Non-functioning lights must be reported by the customer and the Company shall undertake to repair the light as soon as reasonably possible during regular working hours.

Customers that request to have their existing HPS lights replaced with the new LED lights would be responsible for paying a \$200.00 service charge to have a company service crew go to their site, remove the old HPS light and install a new LED light.

Monthly Rate:

Existing pole and existing secondary facilities:

100 watt, 8,500 nom. lumens	\$ 17.76 per month, per light
250 watt, 24,000 nom. lumens	\$ 29.85 per month, per light
60 watt, 7,100 nom. lumens	\$ 17.76 per month, per light
177 watt, 18,050 nom. lumens	\$ 29.85 per month, per light

New pole and single span of new secondary facilities:

100 watt, 8,500 nom. lumens	\$ 20.51 per month, per light
250 watt, 24,000 nom. lumens	\$ 32.77 per month, per light
60 watt, 7,100 nom. lumens	\$ 20.51 per month, per light
177 watt, 18,050 nom. lumens	\$ 32.77 per month, per light

Bills shall be rendered in equal monthly installments without provision for partial or seasonal service.

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

(continued on Sheet No. D-31.00)

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Kenneth A. Dragiewicz, President
Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Ninth-Revised Sheet No. D-32.00
Cancels Eighth-Revised Sheet No. D-32.00

STREET AND HIGHWAY LIGHTING SERVICE

Availability:

Open to the State of Michigan or any political subdivision thereof having jurisdiction over public streets or roadways, for street or highway lighting service for any system where the Company has existing distribution facilities appropriate for supplying such services.

Hours of Service:

Dusk to dawn service controlled by photo-sensitive devices which provide service every night and all night for approximately 4,200 hours per year.

Nature of Service:

The Company shall furnish, install and own the entire equipment, including wood poles, overhead lines, luminaires, supporting brackets for wood pole mounting and lamps. All new installations shall consist of a light emitting diode (LED) fixture. Existing high-pressure sodium (HPS) lights shall continue to be maintained by the company until such time as the fixture is damaged or the Company determines it needs to be replaced. At that time, it will be replaced with an LED fixture. Non-functioning lights must be reported by the customer and the Company shall undertake to repair the lights as soon as reasonably possible during regular working hours.

Monthly Rate:

The charge per light, with the Company reserving the right to select the type of fixture to be installed, shall be:

*For Service from XXXX X, 2024 to June 30, 2025: \$ 16.21 per month, per
light For Service from July 1, 2025 to June 30, 2026: \$ 18.63 per month, per
light For Service from July 1, 2026 to June 30, 2027: \$ 21.05 per month, per
light For Service from July 1, 2027 to June 30, 2028: \$ 23.46 per month, per
light For Service on or after July 1, 2028: \$ 25.88 per month, per
light*

Bills shall be rendered in equal monthly installments without provision for partial or seasonal service.

(continued on Sheet No. D-33.00)

Issued, by
Kenneth A. Dragiewicz, President
Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Third-Revised Sheet No. D-67.00
Cancels Second-Revised Sheet No. D-67.00

RESIDENTIAL PLUG-IN ELECTRIC VEHICLE SERVICE

Availability:

Open to any customer eligible for Residential Service who uses Plug-In Electric Vehicles (PEV) and take service from the Company. This rate is not available for commercial or industrial service, or for resale purposes. Customers under this tariff may not operate distributed generation resources or participate in the Company's Net Metering Program.

The customer can select from two billing options, both of which include metering that is capable of separately identifying PEV usage. Customer-specific information will be held confidential and the data presented in any analysis will protect the identity of the individual customer.

Nature of Service:

Alternating current, 60 hertz, single phase, 120/240 volts.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in (Sheet No E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Option 1 - Separately Metered PEV Time-of-Day: An additional single phase, multi-register meter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage from all other kWh usage at the residence. PEV kWh usage will be billed at the following Monthly Rates and all other kWh usage will be billed separately at Residential Rates.

Distribution Charges:

Customer Charge: \$ 5.25 per customer per month
Energy Charge: \$ 0.07926 per kWh for all kWh consumed

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

(continued on Sheet No. D-68.00)

Issued, by
Kenneth A. Dragiewicz, President
Alpena, MI 49707

Effective for service rendered on
and after

Issued under authority of the
Michigan Public Service
Commission dated,
in Case No. U-21488

M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Third-Revised Sheet No. D-68.00
Cancels Second-Revised Sheet No. D-68.00

RESIDENTIAL PLUG-IN ELECTRIC VEHICLE SERVICE

(Continued from Sheet No. D-67.00)

Power Supply Charges:

Energy Charge: **\$ 0.08536** per kWh for all kWh consumed during the on-peak period
 \$ 0.04423 per kWh for all kWh consumed during the off-peak period

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

Minimum Charge:

The Customer Charge and Renewable Energy Surcharge.

Option 2 - Sub-metered PEV Time-of-Day: A standard meter will measure total residence kWh usage and an additional submeter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage only. Total residence usage will be billed at Residential Service Monthly Rates. A second meter charge will apply and for all off-peak PEV kWh usage additional credits will apply as follows:

Distribution Charges:

Second Meter Charge: \$3.00 per customer per month

Power Supply Charges:

Power Supply Charge Credit: **\$ 0.04113** per kWh for all kWh consumed during the off-peak period

Minimum Charge:

The Customer Charge, Renewable Energy Surcharge and a second meter charge shall apply.

(continued on Sheet No. D-69.00)

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Commission dated,
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M.P.S.C. No. 9
Alpena Power Company
(To Revise On-Peak & Off-Peak Hours & Holidays)

First-Revised Sheet No. D-69.00
Cancels Original Sheet No. D-69.00

RESIDENTIAL PLUG-IN ELECTRIC VEHICLE SERVICE

(Continued from Sheet No. D-68.00)

Customer Switching Service Charge:

\$5.00 each time a customer switches between Generation Service providers. This includes switches from one AES to another, from the Company to an AES, and from an AES to the Company. The customer may switch Generation Service providers at the end of any billing month provided the notice requirements of (Sheet No. E-6.00, Section 2.4) are met. The Customer Switching Service Charge shall not be applied for the first switch of each calendar year or at a time the customer returns to its immediately previous Generation Service provider because the customer was Slammed by an AES.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the unpaid balance, net of taxes, shall be assessed to any bill which is delinquent. The late payment charge shall not apply to customers participating in the Winter Protection Plan.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

On-Peak Hours: ***1:00 p.m. to 7:00 p.m.***

Off-Peak Hours: All other hours

Holidays Designated by the Company:

The following are designated as holidays by the Company:

New Year's Day

Labor Day

Memorial Day

Thanksgiving Day

Independence Day

Christmas Day

New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event that they fall on a Sunday, the Holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the Holiday remains on that Saturday.

Rules and Regulations:

Service under this rate is governed by the Company's Standard Rules and Regulations. The charges under this rate are subject to the General Terms and Conditions of Rate Schedules (Sheet No. D-1.00 through Sheet No. D-4.00).

Issued by
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Alpena, MI 49707

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M.P.S.C. No. 9
Alpena Power Company
(To revise rate)

Third-Revised Sheet No. D-70.00
Cancels Second-Revised Sheet No. D-70.00

GENERAL SERVICE PLUG-IN ELECTRIC VEHICLE

Availability:

Open to any customer eligible for the General Service Rate who uses Plug-In Electric Vehicles (PEV) and take service from the Company. This rate is not available for Residential Service, or for resale purposes. Total load is not to exceed 35kW, measured on a 15-minute interval basis. Customers under this tariff may not operate distributed generation resources or participate in the Company's Net Metering Program.

The customer can select from two billing options, both of which include metering that is capable of separately identifying PEV usage. Customer-specific information will be held confidential and the data presented in any analysis will protect the identity of the individual customer.

Nature of Service:

Alternating current, 60 hertz, single phase or three-phase, the particular voltage level in each case to be determined by the Company.

Customer Choice of Generation Service Provider:

A customer may choose to have its Generation Service provided by an Alternative Electric Supplier, under the terms and conditions applicable to Retail Access Service as delineated in (Sheet No E-1.00). A customer whose Generation Service is provided by an AES is subject to the Distribution Charges shown below but is not subject to the Power Supply Charges shown below.

A customer that does not choose to have its Generation Service provided by an AES shall be provided Full Requirements Service by the Company and is subject to both the Distribution Charges and the Power Supply Charges shown below.

Monthly Rate:

Option 1 - Separately Metered PEV Time-of-Day: An additional multi-register meter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage from all other kWh usage at the location. PEV kWh usage will be billed at the following Monthly Rates and all other kWh usage will be billed separately at General Service Rates.

Distribution Charges:

Customer Charge: \$ 7.50 per customer per month

Energy Charge for service from XXXX X, 2024 to June 30, 2025: \$ 0.07439 per kWh for all

kWh Energy Charge for service from July 1, 2025 to June 30, 2026: \$ 0.07426 per kWh for all

kWh Energy Charge for service from July 1, 2026 to June 30, 2027: \$ 0.07413 per kWh for all
kWh

(continued on Sheet No. D-71.00)

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GENERAL SERVICE PLUG-IN ELECTRIC VEHICLE
(Continued from Sheet No. D-70.00)

Monthly Rate: (continued)

Distribution Charges: (continued)

Energy Charge for service from July 1, 2027 to June 30, 2028: \$ 0.07401 per kWh for all kWh

Energy Charge for service on and after July 1, 2028: \$ 0.07388 per kWh for all kWh

Energy Waste Reduction Surcharge:

This rate is subject to the Energy Waste Reduction Surcharge shown on Sheet No. D-4.91.

Power Supply Charges:

Energy Charge: \$0. *0.08801* per kWh for all kWh consumed during the on-peak period

\$0. *0.04560* per kWh for all kWh consumed during the off-peak period

Power Supply Cost Recovery:

This rate is subject to the Company's Power Supply Cost Recovery Factors as shown on Sheet Nos. D-3.00 and D-4.00.

Renewable Energy Surcharge:

This rate is subject to the Renewable Energy Surcharge shown on Sheet No. D-4.90.

Note: Power Supply Charges are applicable only to customers who receive Full Requirements Service from the Company.

Minimum Charge:

The Customer Charge and Renewable Energy Surcharge.

Option 2 - Sub-metered PEV Time-of-Day: A standard meter will measure total kWh usage and an additional submeter capable of measuring electrical energy consumption during on-peak and off-peak billing periods will be installed to separately measure PEV kWh usage only. Total usage will be billed at General Service Monthly Rates. A second meter charge will apply and for all off-peak PEV kWh usage additional credits will apply as follows:

Distribution Charges:

Second Meter Charge: \$3.00 per customer per month

Power Supply Charges:

Power Supply Charge Credit: \$(*0.04241*) per kWh for all kWh consumed during the off-peak period

Minimum Charge:

The Customer Charge, Renewable Energy Surcharge and a second meter charge shall apply.

(continued on Sheet No. D-72.00)

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Michigan Public Service
Commission dated,
in Case No. U-21488

M.P.S.C. No. 9
Alpena Power Company
(To Revise On-Peak & Off-Peak Hours & Holidays)

First Revised Sheet No. D-72.00
Cancels Original Sheet No. D-72.00

GENERAL SERVICE PLUG-IN ELECTRIC VEHICLE
(Continued from Sheet No. D-71.00)

Customer Switching Service Charge:

\$5.00 each time a customer switches between Generation Service providers. This includes switches from one AES to another, from the Company to an AES, and from an AES to the Company. The customer may switch Generation Service providers at the end of any billing month provided the notice requirements of (Sheet No. E-6.00, Section 2.4) are met. The Customer Switching Service Charge shall not be applied for the first switch of each calendar year or at a time the customer returns to its immediately previous Generation Service provider because the customer was Slammed by an AES.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the unpaid balance, net of taxes, shall be assessed to any bill which is delinquent.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak.

On-Peak Hours: **1:00 p.m. to 7:00 p.m.**

Off-Peak Hours: All other hours

Holidays Designated by the Company:

The following are designated as holidays by the Company:

New Year's Day

Labor Day

Memorial Day

Thanksgiving Day

Independence Day

Christmas Day

New Year's Day, Independence Day, and Christmas Day, by definition, are predetermined dates each year. However, in the event that they fall on a Sunday, the Holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the Holiday remains on that Saturday.

Rules and Regulations:

Service under this rate is governed by the Company's Standard Rules and Regulations. The charges under this rate are subject to the General Terms and Conditions of Rate Schedules (Sheet No. D-1.00 through Sheet No. D-4.00).

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Alpena, MI 49707

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Michigan Public Service Commission
dated,
in Case No. U-21488

**SECTION F
STANDARD FORMS INDEX**

**STANDARD FORMS, INCLUDING APPLICATIONS, AGREEMENTS AND CONTRACTS FOR
ELECTRIC SERVICE. ELECTRIC LINE EXTENSIONS, STREET LIGHTING ETC.**

F1. Residential, Commercial, or Industrial Overhead Service

<https://www.alpenapower.com/new-service/>

F2. Residential, Commercial, or Industrial Underground Service

<https://www.alpenapower.com/underground-service-2/>

F3. Outdoor Protective Lighting Service

<https://www.alpenapower.com/outdoor-protective-lighting/>

F4. Credit Card Enrollment Form

<https://www.alpenapower.com/wp-content/uploads/2023/03/MONTHLY-CREDIT-CARD-ENROLLMENT-FORM-03.13.23.pdf>

F5. Direct Payment Enrollment Form

https://www.alpenapower.com/wp-content/uploads/2013/12/AUTOMATIC_PAYMENT_ENROLLMENT_FORM.pdf

F6. Emergency Contact Form

<https://www.alpenapower.com/emergency-contact-form/>

F7. Landlord Update Form

<https://www.alpenapower.com/wp-content/uploads/2013/12/LANDLORD-FORM-2013.pdf>

F8. Medical Hold Form

<https://www.alpenapower.com/wp-content/uploads/2018/03/Medical-Hold-Form.pdf>

F9. Voluntary Green Pricing Program Application

<http://www.alpenapower.com/wp-content/uploads/2018/04/voluntary-green-pricing-program-application-2018.pdf>

F10. Standard Purchase Power Agreement

<https://www.alpenapower.com/wp-content/uploads/2020/12/Power-Purchase-Agreement.pdf>

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Alpena, MI 49707

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Michigan Public Service
Commission dated,
In Case No. U-21488

PROOF OF SERVICE

STATE OF MICHIGAN)

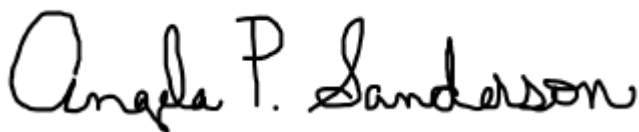
Case No. U-21488

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on July 23, 2024 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).


Brianna Brown

Subscribed and sworn to before me
this 23rd day of July 2024.



Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

Service List for Case: U-21488

Name	On Behalf Of	Email Address
Alpena Power Company	Alpena Power Company	kd@alpenapower.com
Anna B. Stirling	MPSC Staff	stirlinga1@michigan.gov
Lesley C. Fairrow	ALJs - MPSC	fairrowl1@michigan.gov
Lori Mayabb	MPSC Staff	mayabbl@michigan.gov
Michael E. Moody	Department of Attorney General	moodym2@michigan.gov
Michael J. Orris	MPSC Staff	orrism@michigan.gov
Timothy M. Gulden	Alpena Power Company	tmgulden@gillardlaw.com

Exhibit 1.04

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

REPORT

COST OF CAPITAL STUDY

for

ST. CROIX VALLEY NATURAL GAS COMPANY, INC.

prepared by

Robert J. Camfield

Nicholas A. Crowley

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC
ECONOMIC CONSULTING AND STRATEGY

June 20, 2019

*(Confidential Work Product;
Not for General Circulation)*

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Not for General Circulation)***

Report

**Cost of Capital Study
for
St. Croix Valley Natural Gas Company, Inc.**

prepared by
Robert J. Camfield
Nicholas A. Crowley
Christensen Associates Energy Consulting, LLC

June 20,2019

EXECUTIVE SUMMARY

This report presents estimates of the *Cost of Equity Capital* for St. Croix Valley Natural Gas Company, Inc. (SCV). The study employs cost of capital methods common to capital valuation and financial economics and takes account of the business context and capital needs of SCV in order to continue to serve Wisconsin's St. Croix Valley with reliable gas supply.

The study is underscored by established fair rate of return principles. The application of these principles results in *just and reasonable* prices paid by consumers for retail gas services. Fair rate of return, moreover, is in keeping with the overarching principles that support the long-established institutional foundations for determining the prices for public utility services in North America. Namely, the rates for utility services are judged to be just and reasonable provided that two conditions are satisfied:

- First, that charges paid by consumers for the services rendered are not unduly burdensome.
- Second, that the revenue flows realized by service providers are sufficient to cover all costs prudently incurred within the provision of service, including a fair rate of return on the capital committed by investors to the convenience and necessity of the public.

To this end, the return on equity recommendations presented herein are based on well-founded estimates of the cost of equity capital (COE), as incurred by SCV.¹

The estimated COE is obtained by applying cost of capital methods to three samples of U.S. equity markets, including *Natural Gas Distributors*, *Moderate-Sized Electric Utilities*, and small *Non-Utility Companies* with moderate profiles of investment risks. The sample entities provide a broad base of equity

¹ Investors *incur* the cost of capital insofar as financial instruments, traded competitively on capital market exchanges, will be valued at opportunity cost—the risk-adjusted highest return available on alternative investments opportunities.

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market experience, for gas and electric utilities and comparable low-risk non-utilities operating on the North American continent. The market-based estimates of the cost of equity are adjusted to take account for cost of capital differences between the U.S. sample entities and SCV, including a premium for small size and adjustments for financial leverage. The table below presents the overall findings of this cost of common equity study for SCV.

**COST OF EQUITY ESTIMATES FOR ST. CROIX VALLEY GAS, BASED
 ON U.S. MARKET EXPERIENCE OF COMPARABLE RISK COMPANIES**

	Range	
	Low	High
COE Estimates, US Exchange-Listed Entities (9.52%)	9.07%	9.97%
<u>Adjustment to U.S. Market Cost Estimates</u>		
Size Premium	2.48%	3.01%
Comparatively Thick Equity Participation	-1.14%	-1.04%
Total	10.41%	11.93%
Average	11.17%	

In summary, cost of equity estimates for the three samples reside within the range of 10.41% to 11.93%, with a midpoint 11.17% across the three cost of equity methods. Our return on equity recommendation follows accordingly. In its deliberation of the of cost of capital, we recommend that the Public Service Commission of Wisconsin (PSCW) endorse the broad-based market approach underlying this COE estimate and set the allowed rate of return on common equity for SCV between 11.0 and 12.0%.²

²² While the analyses performed in this study suggest an estimation range reaching below 11.0%, such result follows directly from a conservative interpretation of the analysis of size premia. Specifically, cost of capital varies inversely with investment and firm size. SCV is considerably smaller than the companies used to estimate size premia. As a consequence, the appropriate size premium is likely to be somewhat understated.

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INTRODUCTION

This report presents estimates of the *Cost of Equity Capital* for SCV. The *cost of equity* is a major component of the overall composite rate of return covering the debt and equity contributed by investors to underwrite a utility's invested capital. Invested capital, generally referred to as the utility rate base, includes net depreciated capital invested in physical facilities, inventory and stores, and working capital. The composite cost of capital is referred to as the *Weighted Average Cost of Capital* (WACC). For purposes of utility regulation, the cost of equity (COE) is referred to as the *Allowed Return on Equity*, or simply *Return on Equity*. Determining the return on equity is vital because, as a practical matter, a utility's rate base typically constitutes a large, cumulative investment amount. Comparatively modest changes or adjustments to the allowed return equity can translate into significant changes in allowed operating income and revenue level.

This cost of equity study employs well-founded methods of estimation. The study draws upon observed market experience over recent years. Whereas the expected returns at the time of issuance is largely observable by inspection, for outstanding debt and preferred stock, the expected return requirement of investors in common equity is not readily observed. Thus, the appropriate return on equity must be inferred through estimation methods.

SUMMARY, COST OF CAPITAL STUDY

Underlying Principles, Objectives

This study utilizes cost of capital methods common to corporate finance and financial economics and takes account of the business context and capital needs of SCV in order to continue to serve the utility's service territory. The study is underscored by established fair rate of return principles. A proper application of these principles results in *just and reasonable* gas services, where the interests of retail consumers and investors who commit capital for the convenience and necessity of the public are appropriately balanced. The main features of fair rate of return principles include:

- Returns Equivalent to those Realized on Investment of Comparative Risk: As codified in key legal decisions across North America, capital committed by investors for the convenience and necessity of the public is entitled to returns equivalent to that realized on investments in similar regions, and of comparable risks.
- Financial Integrity: The process of regulatory governance must yield flows of revenue sufficient to cover all prudently incurred costs associated with the provision of utility services, including an adequate return on the capital committed by investors. In turn,

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adequate return on capital preserves and maintains the financial integrity of the service provider.

- Ability to Raise Capital on Fair Terms When Needed: The utility and its investors are entitled to adequate returns on capital so that the utility can raise additional capital as necessary, on fair and equitable terms and conditions—*i.e.*, an acceptable interest rate level.

The above principles are in keeping with the decisions and precedents of the PSCW, both stated and implied: To this end, the return on equity recommendations are based on well-founded estimates of the cost of equity; indeed,³ the resulting return on equity recommendation is based on a full complement of cost of capital methods. These methods are general to financial markets and can be applied to the market experience in North America. Accordingly, the resulting estimates of the cost of equity reflect a necessary level of market depth and liquidity to ensure that the cost of equity estimates are reliable. Cost of equity results drawn from this experience are then adjusted to take account of specific characteristics of SCV.

Return on Equity Recommendation

The estimated COE is obtained by applying cost of capital methods to three samples of U.S. equity markets including *Natural Gas Distributors*, *Moderate-Sized Electric Utilities*, and small *Non-Utility Companies* with moderate risk profiles. These market-based cost of equity estimates are adjusted in order to take account of cost of capital differences between the three samples drawn from exchange-traded equity markets and SCV, including a small-size premium and financial leverage.

As stated above, the cost of equity capital is not observable, and thus cannot be estimated precisely. Accordingly, it is appropriate to apply a range of methods of estimation. The immediate study employs well-recognized cost of capital models: *Capital Asset Pricing Model*, *Discounted Cash Flow*, and *Comparable Earnings* based upon historical realized returns of comparable-risk companies, where such returns serve as a basis of future earnings performance.⁴ The cost of capital methods selected for the immediate study are longstanding approaches within the cost of capital toolbox, and well accepted by regulatory authorities.

³ Investors *incur* the cost of capital insofar as financial instruments, traded competitively on capital market exchanges, will be valued at opportunity cost—the risk-adjusted highest return available on alternative investments opportunities.

⁴ Other approaches are available including *Risk Premium Analysis*, *Factor Models*, variants of *Arbitrage Pricing Theory* (“APT”), and other *CAPM* models such as “*Sum Beta*” (Non-synchronous estimation).

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The table below presents estimates of the cost of common equity across the comparable risk electric and gas utilities and non-utility companies drawn from these three methods. These samples provide a broad base of equity market experience of utilities and comparable low-risk non-utilities operating on the North American continent.

**COST OF EQUITY ESTIMATES FOR ST. CROIX VALLEY GAS, BASED
 ON U.S. MARKET EXPERIENCE OF COMPARABLE RISK COMPANIES**

	Range	
	Low	High
COE Estimates, US Exchange-Listed Entities (9.52%)	9.07%	9.97%
<u>Adjustment to U.S. Market Cost Estimates</u>		
Size Premium	2.48%	3.01%
Comparatively Thick Equity Participation	-1.14%	-1.04%
Total	10.41%	11.93%
Average	11.17%	

In summary, cost of equity estimates for the three samples reside within the range of 10.41% to 11.93%, with a midpoint 11.17% across the three cost of equity methods. The return on equity recommendation follows from this estimate. In its deliberation of the of cost of capital, we recommend that the PSCW endorse the broad-based market approach underlying this COE estimate and set the allowed rate of return on common equity for SCV between 11.0 and 12.0%.⁵

INSTITUTIONAL FOUNDATION FOR RETURN ON EQUITY

Statutory and legal guidelines for utility regulation across the North American continent are delineated in key decisions by authorities in Canada and the United States. For the immediate purposes, it is the principles that govern the return on capital, referred to as the *fair rate of return*. As a point of departure, the statutory principles of rate of return for public utilities rest substantially upon two decisions of the Supreme Court of the United States. In the *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia* case (262 U.S. 679, 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

“...A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally

⁵ While the analyses performed in this study suggest an estimation range reaching below 11.0%, such a result follows directly from a conservative interpretation of analysis of the size premium. Specifically, cost of capital varies inversely with investment and firm size. SCV is considerably smaller than the companies used to estimate the size premium. As a consequence, the size premium is likely to be somewhat understated.

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being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.”

A second landmark decision of the U.S. Supreme Court echoed the “Bluefield” decision and expanded upon the fair return standard for capital committed to public utilities. This second decision is the *Federal Power Commission v. Hope Natural Gas Company* case (320 U.S. 391, 1944); a relevant passage of the decision, referred to as *Hope*, is as follows:

“From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with return 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 attract capital.”

These longstanding decisions provide a more-or-less universally accepted framework for determining the fair rate of return on capital committed by investors to public service.⁶ In these decisions, the U.S. Supreme Court codified, in clear and well understood terminology, benchmarks for setting fair and equitable prices for utility services, including natural gas, while also providing a fair rate of return on the capital provided by investors. The immediate challenge for regulators, regulated utilities, and interested parties to rate setting proceedings is to operationalize these principles in contemporary regulatory processes.

⁶ In the Permian Basin Area Rate Cases (390 U.S., 747, 1968), the U.S. Supreme Court stressed that:

“the court must determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. The court's responsibility is not to supplant the Commission's balance of these interests with one more nearly to its liking, but instead to assure itself that the Commission has given reasoned consideration to each of the pertinent factors.”

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FUNDAMENTALS OF COST OF CAPITAL

Definitions

The *Cost of Capital* is the underlying interest rate used by investors to discount and value the expected benefit flows obtained from holdings of financial assets,⁷ and referred to as the rate of discount, or simply the discount rate. The cost of capital is the compensation required by investors for postponing consumption, for expected inflation, and for exposure to capital risks of various dimensions, where such risks are, on the one hand, general to macroeconomies and financial markets but also specific to the underlying investment vehicles used to underwrite capital.

The cost of capital is determined by the demand for capital, supply of savings, expectations of inflation, and perceptions of risks harbored by participants in capital markets. The demand for capital is determined by expectations of future levels of economic activity, while expected inflation is driven largely by monetary policy over the relevant timeframe. Perceptions of risk, in turn, cover many dimensions of uncertainty including future performance of individual investments and macroeconomies, and policy of governing authorities regarding fiscal expenditures. Actions of sovereign governments have immense power to moderate, or contribute to, risk and to thus facilitate or hinder the formation of capital. Left unchecked, rising levels of outstanding debt across public and private sectors can lead to rapid contractions in macroeconomic activity as the potential for wide scale capital defaults and deleveraging becomes the consensus view. Going forward, the result can assume a lower path of economic activity over extended years. Furthermore, the effects of natural phenomena including violent storms, floods, and droughts are manifest in capital risks. Social and institutional stability matters: in some regions, the potential for unfair taxation; confiscation of investment; civil unrest, war and ultimately failed states are ongoing concerns. In brief, the cost of capital—the discount rate stated in nominal terms—increases with rising demand for capital, with expectations of higher rates of inflation, and with heightened perceptions of risk. As a practical matter, risk is arguably the key contributing factor for the estimation of the cost of capital.

⁷ Financial assets are one form of capital. More generally, *Capital* refers to economic resources of a durable nature that contribute to the production of goods and services, or provide services directly. Capital resources of an economy are readily at hand: manufacturing equipment, software, commercial buildings, residential dwellings, public infrastructure including highways, ports, airports and, importantly, the accumulation of skills and knowledge of the workforce (reference Gary S. Becker, *Human Capital*, National Bureau of Economic Research, 1975). Capital comes about from the accumulation of savings over time, where savings refers to the proportion of the potential output of an economy not consumed as current goods and services. Essentially, savings is the share of output (potential) held back and invested in—*i.e.*, put into—capital resources. The cumulative level of investment over time, covering decades, constitutes the capital stock of a macroeconomy and social systems thus served.

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Financial assets include a multitude of debt vehicles, equity, and derivatives,⁸ and are tailored to participants of capital markets including household, small business, corporate, and public entities. Market participants including lenders and holders of common and preferred stock supply capital as investors, while borrowers including public and private entities and common stock-issuing companies constitute the demand side of capital markets. Commercial banks, credit unions, finance companies, capital exchanges, and investment banks serve as intermediaries that provide the institutional means that facilitate the interaction and linkage of the supply and demand sides of capital markets, focused on financing. These functions essentially include lending, borrowing, and the issuance of equity vehicles. Banks and credit unions borrow (and store) financial assets that in turn are invested in the form of debt and, to a lesser extent, equity. Household debt vehicles include, for example, personal loans covering appliances, household services, and credit card mechanisms through finance companies and banks, and real estate loans in the form of mortgage debt and collateralized market value (home equity). Business loans include short-term loans and lines of credit with banks, inventory financing through business wholesalers, and commercial paper of various terms and credit risk ratings. Corporate debt can be in the form of lines of credit and notes with banks and commercial lenders, mortgage and debenture bonds, while government debt can be in the form of revenue bonds of municipalities, and short- and long-term debt vehicles of various terms.

Equity (or, Common Equity) of private entities such as electric utilities like SCV refers to net accumulated value of the contributed capital by equity investors. At a general level, equity is in the form of common and preferred stock, and includes the accrual of retained earnings, where investors, through the purchase of stock, assumes a share in the ownership of a corporate entity. In some cases, debt instruments can participate in equity returns and may also have rights of conversion to common stock.

The cost of capital associated with financial assets reflects the risks of the underlying capital, and is determined by investors, in view of other investment opportunities. Overall, households may hold savings individually or contribute savings passively through agency processes including retirement plans, pensions, and various publicly-sponsored savings plans. Examples include the social security system of the U.S., old-age pension system of the U.K, and Canada's national pension plan. Regardless, savings flows to

⁸ Derivatives are financial instruments whose value depends on investor expectations regarding the inherent value of the underlying assets. Derivatives, common forms of which include options and forward insurance contracts such as credit default swaps, also provide a basis to hedge—and to speculate on—risks associated with the underlying value and market worth of the asset.

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the macro economy and provides the means to invest, underwriting and funding of capital in the form of physical facilities, inventories, software, skills development, and knowledge acquisition of various types (medical research, for example, is a form of human capital). To investors (savers) who hold financial assets directly or indirectly, expected benefits are in the form of future cash flows including interest payments, dividend payments, market appreciation, and return of principal. When investors supply funds to entities such as utilities and public entities (e.g., government bonds), not only are they postponing consumption by foregoing value otherwise obtained from alternative expenditures, they are also exposing funds to the potential devaluation from ongoing inflation as well as to various uncertainties and risk attending future cash flows. Investors are willing to incur these risk factors only if they are adequately compensated.

While the market prices of other inputs including labor, materials, and energy can be easily verified, the cost of capital—essentially, the price of capital—is not easily discerned, thus requiring estimation through the cautious application of analytical methods. The cost of capital remains positive in the absence of inflation and risks, as savers require compensation for foregoing the right to use the funds saved for current consumption of goods and services—essentially, the time value of money.⁹

In addition to the global risks alluded to above (weather, institutional stability, public policy, etc.), dimensions of risk also cover idiosyncratic factors associated with specific capital resources, such as those of individual entities, asset facilities, or companies. Accordingly, financial markets will re-price downward the bonds of a private company, should the *current* financial condition of the company suddenly decline. Essentially, the decrease in the company's current condition reflected as reduced interest coverage—causes the expectation of the future condition of the company also to decline. Expectations of future financial conditions (possible “future states”, as perceived) of the specific company constitute idiosyncratic risks. Because the cost of capital rises with increased risks, the price of the bonds decline.¹⁰

Financial Markets

To facilitate the commitment of capital (investment) by savers and their agents to the firm, the firm offers property rights, including bonds or promissory notes to lenders and shares of stock to equity investors. These property rights define the commercial terms and conditions under which savers and their agents,

⁹ Numerous exceptions to this general statement can be cited. As an example, the recent experience of exceptionally low interest rates in many Western economies is telling, wherein real interest rates on virtually risk-free financial instruments were negative.

¹⁰ Bond prices and discount rates, in the form of the interest rates or bond yields (and yield to maturity), move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

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as investors, commit capital. Property rights are financial assets, and are generally tradable in organized financial markets, on an *over-the-counter* basis, or in bilateral transactions. Financial assets are claims on the income of the firm as compensation for the commitment of capital and constitute the fiduciary obligations of the firm.

In the case of long-term debt including mortgage bonds, debentures, and long-term notes, the interest on the principal (face) amount of a bond (debt) or the coupon rate on the share of preferred stock defines the level of compensation. Often, the interest rate is a predefined annual rate that remains fixed over the term of the debt instrument. However, long-term debt instruments may incorporate other provisions which, in essence, provide for more complete contracting by managing uncertainty through risk sharing between the debt holders (lenders) and issuers (borrowers). These provisions can include adjustments to the rate of interest to reflect contemporary market conditions *and* rates of inflation, call provisions, participation in the earnings of the firm, conversion rights, and voting rights in the management of the firm.

In the case of short-term debt, credit lines or promissory notes with commercial banks define the mechanism by which interest is determined. As an example, commercial terms may clarify that interest is to be paid monthly on the outstanding daily balance in the case of lines of credit, or quarterly in the case of a promissory note. The rate of interest applied to the outstanding balance can be tied (indexed) to the interest rate on obligations of some widely known financial market vehicle—say, the London Interbank Offer Rate (LIBOR)¹¹ or Fed Funds, or the prime rate of commercial banks (as surveyed and published)—which also varies daily or monthly.

Common stock property rights are somewhat different from other financial obligations because, as owners of the firm, the returns to shareholders are residual, following the compensation to other resources employed by the firm including debt obligations. Common equity is essentially compensated last, and bears the burden of much of the business, regulatory, and financial risks of investor-held entities. For this reason, common equity is more costly than other forms of financial instruments, in virtually all cases.

¹¹ LIBOR markets will be superseded in 2021 by a newly formed short-term market medium, a consequence of irregularities in the day-to-day operating procedures for determining LIBOR rates, both in Europe and the U.S.

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As with many other markets, capital markets have primary and secondary dimensions. Primary markets are the institutions and processes that facilitate the initial sale of the financial obligations of the firm to investors, whereas secondary markets are structured market processes that provide the means by which investors can purchase and sell existing rights including shares of stock and debt obligations.

Financial instruments can assume many forms. To the extent that debt securities (e.g., bonds) and equity shares are actively traded on the larger exchange and over-the-counter markets, the prices for securities reflect inherent risks perceived by investors; the conditions underlying these markets are generally considered to be sufficiently liquid and competitive. However, to the degree that markets are less liquid with little transaction activity or, secondarily, that financial obligations carry specialized and non-conventional terms, holders of such obligations assume higher risks, other factors held constant. This is the case where the pool of buyers and sellers is limited and the volume of transactions is comparatively small. Relatively low levels of liquidity imply higher transaction costs and risks to investors, which translates directly into higher costs of capital to the firm.

Markets can be described as *workably competitive*,¹² should certain conditions be satisfied: 1) a large number of buyers and sellers, 2) information relevant to the determination of prices is readily available, complete, and not costly, and 3) transactions costs including the costs of entry and exist are comparatively low. Because of the workably competitive nature of financial markets, arbitrage opportunities are more or less exhausted. This means that, for both primary and secondary markets, financial property rights trade at levels (prices) such that perceived risks and opportunities for prospective returns to capital are appropriately balanced and approximate those of other investment opportunities. Thus, above-normal returns, which implicitly include compensation for risks, cannot be readily be realized by investors over prospective periods in systematic fashion.

Market Efficiency and Capital Valuation

Expected market returns is the core concept. Under the assumption of efficient markets, competition inherent to U.S. and selected worldwide financial markets implies that the prices of common shares (share prices) and bonds reside at levels that reflects the opportunity cost of capital. As an example, assume that the perceived risks attending the expected returns to common shareholders of Firm A are equivalent to

¹² Relevant to the notion of market competition is *contestable markets* wherein, as shown, a small number of a firms can result in competitive, marginal cost-based prices, providing that entry and exist is costless. As a practical matter, few markets fully satisfy these strict conditions.

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those of Firm B and other firms. If the share prices of Firm A imply an expected market return of 10%, while the prices of Firm B and other firms of comparable risks suggest (allow) market returns of 13%, the market price of Firm A will fall to a level that provides a basis for market returns of just 13%, prospectively. A price that allows for a 10% prospective market return is insufficient in the presence of opportunities for a market return of 13% on alternative investments of comparable risk. Essentially, the 13% market rate of return on investment alternatives constitutes the opportunity cost of capital. Most remarkable is the expedience—literally, in minutes for highly liquid financial markets—with which share prices adjust to levels that appropriately balance prospective returns to equilibrium levels *based upon perceptions of risks*. In short, equivalent and comparable risks translate directly into comparable market rates of return, as expected. This is the cost of capital of common shareholders in the firm.

As previously mentioned, the cost of capital is a function of the demand for and supply of capital, as well as investor expectations of inflation and perceptions of risks.¹³ Because the conditions of demand and supply as well as expectations of inflation are more-or-less common to financial markets at any point in time, financial vehicles are largely differentiated by risks. Hence, the expected returns and prices of bonds and common shares (normalized for denomination and size) at any point in time are largely if not exclusively differentiated by perceptions of risk.

In summary, whereas the cost of skilled labor, materials and supplies, and inputs (including fuel) employed in the provision of utility services are expressed in money terms, the cost of capital is expressed as an interest rate, typically shown as an annual percentage of investment. This means that the costs of the capital resources employed by SCV, including generation equipment, power delivery systems such as transformers and lines, meters, trucks and vehicles, computer systems, software, office facilities and buildings, inventory and stores, and land—essentially, the rate base of SCV—are reflected as annual carrying charges. The cost of capital for SCV—or perhaps more accurately, the *cost rate of capital*—is referred to as the *required rate of return* (%) on the capital resources committed by investors to SCV, where capital is valued at either original cost or fair value.¹⁴

¹³ Currency risks contribute to the overall risks associated with holding financial assets denominated in currencies other than that of the investor.

¹⁴ For the determination of setting retail utility prices in the U.S. and elsewhere, the regulatory convention is to value the capital of public utilities at original cost. Other measures of capital value including *fair value* and *trended original cost* have been applied, particularly during eras of high rates of inflation and under circumstances where original cost measures cause distortions in the relevant costs and prices of complementary or substitute inputs.

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Utility Revenues, Weighted Average Cost of Capital

As mentioned, total net invested capital is the basis for setting regulated prices and is the primary component of a utility's rate base. Public utilities such as SCV utilize and employ substantial levels of capital resource inputs (net capital) to provide utility services.

In general, the flow of revenues less the costs of non-capital inputs to the firm such as operating expenses provides a level of dollar returns to capital, in the form of operating income. If the level of income matches expectations, investors realize returns equivalent to the overall cost of capital. As discussed more fully below, the overall cost of capital, often referred to as the *weighted average cost of capital* ("WACC") and expressed in percentage terms, incorporates the pool of financing vehicles used by the utility to underwrite and fund the capital that it employs in the provision of services to the public. In summary, the WACC is the composite weighted cost of the financing vehicles including short-term debt, long-term debt such as mortgage bonds, preferred stock, and common stock.¹⁵ These financing vehicles are property rights and constitute the financial contracts between lender and equity investors, and the firm including government entities and private companies.

Utilities must compete with other entities in open markets for the input factors (labor, materials, and energy inputs). The prices of these inputs are set in the marketplace,¹⁶ and the costs of these inputs that are incorporated into the total costs and required revenues. Likewise, prices for capital resources such as equipment, facilities, software, inventories, and working capital are also set by markets. Since utilities including SCV must directly (or ultimately) attract capital through open financial markets, there exists a market price to pay for the capital they require—in short, the market cost of capital that implicitly exhausts all opportunities for higher returns, given perceived risks.

¹⁵ As mentioned earlier, the capital structure and overall rate of return, for purposes of regulation, can also include customer deposits. This is the case for SCV.

¹⁶ The discussion recognizes that entities including utilities may not participate in workably competitive markets for the various inputs that they require. Along this line, however, it is useful to mention that, worldwide, the larger financial markets are generally considered to be relatively competitive, where the notion of competition implies that the actions and behavior by individual market participants including buyers and sellers have, as a general rule, no significant impact on the market clearing prices or the availability and sale of goods and services. Innumerable examples challenging the assumption of workable competition can be cited. Within capital markets, for example, the sudden sale or purchase of large blocks of shares of a specific entity may have significant impact on the market value of shares.

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REGULATION, DEMAND FOR CAPITAL, CAPITAL ATTRACTION

The cost of capital concept may also be interpreted from the perspective of internal investments and the demand for resources. Regulated utilities accommodate, by law, the ongoing and steadily rising demand for services, which involves the expanding employment of resources, capital in particular. Senior managers of firms, as agents for the ownership or controlling interest of the entity such as shareholders or a local municipality, are responsible for ensuring that the expected internal returns on incremental capital committed by the firm are equivalent to the cost of capital to the firm—*i.e.*, investors' rate of return requirements. The adequacy of the internal returns on incremental investment by electric utilities to fund capital at full opportunity costs, however. This is highly dependent upon the soundness of the regulatory governance structure to ensure that the utility has the opportunity to obtain sufficient revenues, which in turn provide adequate returns on incremental investment in new facilities.

When the rate of return, set by regulators, leads to inadequate returns to capital or to the expectation that returns to capital are likely to be insufficient, utility managers are understandably reluctant to make investments in infrastructure. Indeed, when the expansion of capital resources occurs under a regulatory requirement including the obligation to serve, the absence of adequate returns may be interpreted to implicitly constitute the confiscation of the capital. Under these regulatory conditions, the utility is forced to provide services that involve new investment, even though adequate returns are not obtainable. The result can be a failure of capital attraction by the utility, and the confiscation of capital of investors—a direct result of the inherent efficiency of competitive capital markets.

Investors, investment rating agencies, investment banks, and commercial bank lenders follow regulatory developments. Markets are sensitive to unexpected changes. The unanticipated shortfall of the allowed return on equity vis-à-vis the cost of equity will cause capital markets to bid down the prices of the outstanding securities of the utility. The reduced market capitalization of the utility constitutes, arguably, the confiscation of the existing capital of holders of the utility's securities. Essentially, the utility has failed to (or simply cannot) attract capital on fair terms—terms that do not cause outstanding investors to incur wealth losses.

In summary, the utility and its managers can often find themselves, as a result of service requirements, forced to invest in real physical assets that are uneconomic from the perspective of the firm and its

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constituent investors, should the return on ongoing investments falls short of the cost of capital.¹⁷ The cost of capital is the minimum rate of return that must be earned on physical assets to justify their acquisition, and thus the regulator must be mindful of the allowed rate of return levels and implement regulatory procedures that provide the utility with an acceptable level of opportunity to realize returns, on the margin, that satisfy the cost of capital—*i.e.*, a rate of return equivalent to that realized on investments of comparable risks. In the context of a binding regulatory constraint, and other regulatory requirements such as obligations to serve, it is sufficient but also necessary for the required rate of return on incremental investment to adequately satisfy the opportunity cost of funds. The regulator should set the allowed rate of return equal to the cost of capital so that the utility is free to satisfy its capital needs and service customers at fair prices.

The aforementioned principle and accompanying rule can be illustrated by example. Suppose a utility has a rate base of \$250 million financed 58% through debt and 42% through equity. Assume that the cost rate of the outstanding debt capital is 7.25%, and that the rate of return on equity capital is 13.0%, giving a weighted average cost of capital of 9.66%. Suppose further that the regulator sets the allowed rate of return at 8.50%, rather than 9.66%. To fully service the property right claims of both bondholders and shareholders, revenues over operating costs should amount to \$24.16 million annually (*i.e.*, $0.0966 \times \$250$ million). An allowed rate of return of only 8.5% on a rate base of \$250 million provides returns to capital equal to just \$21.25 million. The returns to total capital (operating income) are sufficient to service the outstanding debt, \$10.51 million (*i.e.*, $\$250 \text{ million} \times 0.58 \times 7.25 \%$). However, bondholders have primary claims to the returns to capital; financial results available to shareholders are residual. Hence, the return available to service equity holders is a mere \$10.74 million, allowing for a realized equity rate of return of just 10.23%, a shortfall of 2.77% which translates into a loss to shareholders of \$2.91 million.

As a consequence, share prices can be significantly bid down, giving rise to a sharp decline in the market capitalization of the firm. The result is a significant wealth transfer from shareholders, as investors, to retail consumers. In short, the capital of investors can be confiscated as a consequence of compromised regulatory outcomes. Further, the regulatory governance structure, particularly where the utility has binding service requirements and constraints, causes a breach of fairness criteria and leads to a failure of the utility to satisfy capital attraction standards where capital can be raised at fair and equitable terms.

¹⁷ Over current years, incremental investment is a particular concern to SCV and other electric utilities in view of aging facilities and the ongoing replacement of the capital stock, where the incremental cost of the physical equipment and resources can be several times greater than the book value of legacy facilities.

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Essentially, higher cost of debt interest charges result from the reduced credit standing in view of the lower levels of interest coverage.

It is useful to pursue this line further and consider the counterfactual case. Specifically, if the allowed rate of return is greater than the cost of capital, the capital investments are undertaken, and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to equity holders, resulting in a rise in share prices. In this case, the wealth transfer occurs from electricity consumers to shareholders.

The upshot is that investments and capital expansion are undertaken by utilities without inappropriate and unfair wealth transfers between consumers and shareholders if, and only if, the allowed rate of return is set at levels which approximate the cost of capital. In the case of the above example, at an allowed rate of return of 9.66% the expected earnings realized on incremental investments are just sufficient to service both the incremental and outstanding claims of debt and equity holders on the capital returns of the utility, no more, no less. In conclusion, setting the allowed rate of return equal to the cost of capital is the only policy that ensures commitment of necessary investments in order to satisfy utility service requirements while also providing fair and equitable returns to investors.

METHODOLOGY: ESTIMATION OF THE COST OF EQUITY

Approach

The cost of common equity is based upon the observed market experience of the common equity shares of samples of companies traded on U.S. financial markets. Stock price data along with various other financial data including capital risks and realized returns for financial market indexes are assessed with cost of equity models. U.S. market-based estimates of the cost of equity for the comparable risk samples are obtained. The U.S. market-based estimates are then adjusted in order to 1) account for the market context of SCV, and 2) the size differences between SCV and the U.S. sample companies.

Methods to *determine the cost of equity* (Models), and *adjustments to cost of equity estimates* are discussed below.

Context for Cost of Equity

It is useful to reiterate three essential points that we elaborated upon above. First, the cost of equity of the firm—opportunities costs incurred by investors in the firm—is a function of perceptions of risk, the

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demand for and supply of capital, and expectations of inflation. Second, the cost of common equity of the firm is equal to the opportunity cost of capital incurred by common shareholders of the firm *contemporaneously*, though the experience of long-term history guides the assessment of opportunity costs. Third, the cost of equity of the firm is equal to the expected market rate of return on alternative investments of comparable risks available to shareholders—i.e., the opportunity cost of capital—within a contemporary timeframe.

The determination of the opportunity cost rate for equity capital is challenging for two reasons. In the case of debt, both the market price and future expected cash flow returns to capital, in the form of dividend payments, are observable by inspection. Thus, the net expected yield to maturity, which reflects the opportunity cost of capital to holders of debt, can be determined directly.¹⁸ This is the market rate of return, *ex ante*. For purposes of determining the overall utility rate of return, however, the cost rate of long-term debt is that which is set at the time of issuance in primary financial markets.

In contrast, expectations of investors about the prospective cash flows and market returns on common equity cannot be observed. Cost of equity must be discerned through estimation. Also, the allowed equity rate of return is typically set according to the current and expected cost of capital, though much of the equity investment was committed in many years past. That is, the cost of equity may change over time as market conditions change, even though the original equity contribution has been in place for some time.

In the determination of cost rate for debt obligations, investors' perceptions of risks are implicit in the primary and secondary market prices of the debt obligations themselves and need not be known or even estimated. In contrast, the determination of the cost of common equity involves an understanding of the perceptions of future risks harbored by investors, as a matter of the consensus view. Perceptions of risk are also not observable, and thus must therefore be inferred with estimation procedures.

To summarize, the cost of common equity can only be discerned through the proper and careful application of well-established methods that provide the cornerstone for modern finance theory. While

¹⁸ This is not absolutely correct. Debt carries a certain likelihood of default by borrowers—default risk. Arguably, the underlying cost of capital should account for the probability distribution that outstanding issues of debt will, mostly likely, pay dividends through the remain term of the issue, as well as the likelihood, however small, will default on debt outstanding.

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the methods employed herein are established, the procedures to determine the cost of equity capital require estimation of key parameters.

Models for Cost of Equity Estimation

In order to develop our recommendation for the rate of return on equity for SCV, we apply three cost of capital methods. These estimation procedures include variants of the constant growth *Discounted Cash Flow* model (DCF), and the *Capital Asset Pricing Model* (CAPM). These classical approaches are commonly recognized within modern finance theory and are readily utilized for purposes of capital valuation. The results of these two formal models of the cost of capital are augmented by an assessment of *Realized Market Returns* for utility and non-utility companies of comparable risks. The three estimation methods are discussed below.

DISCOUNTED CASH FLOW: The constant growth Discounted Cash Flow (DCF) model was originally developed by Myron Gordon in 1957, and has been broadly applied during the following decades. In its classic, one-stage form, the derived DCF model defines the cost of capital as the sum of the adjusted dividend yield, and expectations of future growth in cash flows to investors, including dividends and future appreciation in share prices. The classic DCF model is as follows:

$$k_{e,j} = D_{0,j}(1 + E(g_j))/P_{0,j} + E(g_j)$$

with,

$k_{e,j}$ = cost of equity capital for asset j

$D_{0,j}$ = current dividends per common share for asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share for asset j

The one-stage form of the DCF approach is elegant and intuitively tractable. As shown above, the model includes two terms, a mathematical result derived from the general form of discounted present value, as applied to a series of benefits over time characterized by uniform growth. A cursory review of historical returns on equities suggests that differences in the observed internal returns to capital, as well as expectations of future returns as expressed by security analysts, contribute to realized market appreciation as well as to the total returns to capital. It is plausible that the *expected path* of future returns harbored by investors may assume a pattern of non-constant growth. To allow for the possibility that the constant growth from discounted cash flow does not fully capture investors' expectations of growth, other forms of DCF are available for purposes of capital evaluation.

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A plausible means to better model expectations of varying growth might be with stochastic models, where the path of returns and growth is a function of time, with a random component. However, stochastic models introduce considerable complexity, while providing little advantage in the form of reduced estimation error.¹⁹ Largely for this reason, the immediate cost of capital study employs the classic DCF model. Appendix I provides a step-by-step derivation of the classical and multi-stage discounted cash flow models shown above.

CAPITAL ASSET PRICING MODEL: The Capital Asset Price Model (CAPM) was developed by William Sharpe (1961) and John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular, portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk-free returns and an *adjusted risk-based return*. Surrogates for risk-free returns can be observed directly in capital markets, including market returns on short- and intermediate-term debt. As a general rule, the cost rates (yields) and market returns of government debt obligations serve as appropriate surrogates.

The adjusted risk-based return is based upon three factors: 1) the covariation of the returns of the asset and that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the *difference* between expected overall returns on risky assets, and risk-free returns. The third

¹⁹ A first-order approximation to stochastic processes, a variant of classic DCF, multiple-step constant growth models known as multi-stage DCF, serves as an approximation of this more complex method. Essentially, multi-stage DCF is a variation of present value theory which postulates that future returns assume a pattern of several growth steps or stages. While any number of stages of constant growth is possible, two or three stages are typically applied. In stylized fashion, the Three-Stage DCF model is shown below:

$$P_{0,j} = (1+g_j)/[(k_{e,j}-g_j)\{D_{0,j}(1-F^5_j) + D_{5,j}(F^5_j - F^{10}_j) + D_{10,j}(F^{10}_j)\}]$$

with,

$k_{e,j}$ = cost of equity capital for asset j

$D_{t,j}$ = current and future dividends per common share for asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share for asset j

$$F_j = (1+E(g_j))/(1+k_{e,j})$$

As shown in the above formulation for the Three-Stage DCF, discounted prospective cash flows are represented by three terms that incorporate the factor “F”, each of which is differentiated by expected growth, $E(g)$. In the Three-Stage approach, investor expectations of future growth are differentiated among time frames. Unlike the single-stage DCF approach, the estimated cost of equity capital solution to the multi-stage model (the discount rate k) can be obtained through a mathematical search procedure that iteratively searches for the discount rate that balances the left- and right-hand-sides of the equation.

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parameter is referred to as the excess return and is equal to the difference between the overall returns to risky assets for equity markets as a whole and the risk-free return rate. The CAPM is shown below:

$$k_{e,j} = r_f + B_{jm}*(r_m - r_f) \quad \text{with, } B_{jm} = \sigma_{jm}/\sigma_m^2$$

where

$k_{e,j}$ = cost of equity capital for risky asset j , stated in percentage terms

r_f = risk-free rate of return

B_{jm} = ratio of the covariation between risky asset j and the market as a whole, σ_{jm} , and the variance of market returns, σ_m^2

r_m = expected rate of return on equity markets, as a whole

Appendix II derives the Capital Asset Pricing Model, as shown above. A succinct derivation of the CAPM model is developed by David Luenberger, to which intermediate steps have been added for purposes of exposition.²⁰

The efficient market hypothesis plays an essential role in the determination of the cost of capital. Specifically, the working assumption, which is largely though not completely borne out by empirical analysis, is that capital markets are fairly efficient. This means that the supply and demand for risky financial assets, as reflected in bid and asked prices to buy and sell shares, result in financial assets being traded at price levels where *rates of return above the cost of capital cannot be systematically realized*. Above-normal returns—returns above the cost of capital—are realized only randomly. Essentially, the opportunities to systematically realize returns above the underlying cost of capital are exhausted by the competitive market process.

Estimating the cost of capital, though not trivial, can be fairly straightforward, and both the DCF and CAPM approaches provide a useful framework. The risks to investors in various sectors of the energy services industry cannot ever be known directly; risks—and hence the implied cost of capital—can only be inferred. Specifically, the determination of useful estimates of the cost of common equity capital within either framework requires a discerning application of theory through careful analysis, such as that presented herein. In particular, the determination of the cost of equity capital faces two overarching assumptions, as follows:

- both approaches are forward looking and thus the results are highly dependent upon useful estimates of investor expectations about future market performance.

²⁰ David Luenberger, *Investment Science*, 1998.

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- the underlying assumptions for DCF and CAPM include, among other things, an efficient market and rational behavior of investors such that all opportunities for above- and below-normal returns to capital are exhausted on an expected value basis. In short, capital markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

It is useful to mention that the notion of *risky assets* can apply to any real or financial asset, wherein the prospective returns from holding the asset are uncertain. Risky assets include commodity contracts, financial property rights, financial derivatives, and real assets such as power delivery and generation facilities of electric utilities. Moreover, risk assessment and option theory can be applied to the analysis of unbundled services, such as electricity transmission development plans. Within the context of this discussion, however, risky assets refer to financial obligations of firms—i.e., common stock—and asset values refers to prices of common stock as observed on major stock exchanges.

REALIZED MARKET RETURNS: Measurements of *Realized Market Returns* and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that *all* financial assets are priced at levels such that the *expected* future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the *Realized Market Returns* methodology can be viewed as a market-based approach of *Comparable Earnings*, and thus fully satisfies the *Bluefield* and *Hope* criteria. More specifically, realized market return for a period is defined as:

$$R_{j, t-t-1} = (P_{j, t} + D_{j, t-t-1} - P_{j, t-1}) / P_{j, t-1}$$

with,

$R_{j, t-t-1}$ = market return realized within the interval $t - t-1$, for financial asset j

$D_{j, t-t-1}$ = dividends paid during the interval $t - t-1$, for financial asset j

$P_{j, t, t-1}$ = market value of financial asset j , at t and $t-1$

The key to successfully applying this third approach is identification and measurement of historical returns in a manner that reasonably reflects expectations of investors about the future outlook.

Observed historical returns and future expected returns of financial assets are ordered according to risks. This ordering is a natural and inevitable result of competitive financial markets: because risk is costly, higher costs must be offset by higher returns. While it is not based upon an explicit model, the analysis of

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the risk premia among classes of risky assets provides a means to infer the underlying opportunity cost of capital.

RISK PREMIA: The underlying concept of the risk premium approach is that *differences* in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns, referred to as risk premia, serve as a surrogate for the compensation for risk over future timeframes. When combined prospectively with the expected cost of short-term debt, risk premia provide a useful benchmark to gauge the underlying cost of equity capital. The immediate application of the Risk Premium approach is codified as follows:

$$k_{e,j} = r_f^{st} + rp_{int-st} + rp_{m-int} + rp_{y-m}^{CAPM} + rp_j^s$$

with,

$k_{e,j}$ = cost of equity capital for risky asset j , stated in percentage terms

r_f^{st} = risk-free rate of return, for a short-term asset

rp_{int-st} = risk premium for intermediate-term asset int with respect to a short-term asset

rp_{m-int} = risk premium for equity market m with respect to an intermediate-term asset

rp_{y-m}^{CAPM} = risk premium for industry y with respect to equity market m , where y refers to the relevant industry sample

rp_j^s = size-based risk premium for risky asset j ²¹

Application of the Risk Premium approach contains two potential pitfalls:

- the opportunity cost of common equity capital, stated in nominal terms, is sensitive to the demand for and supply of capital;
- risk premia among debt and equity instruments are also sensitive to expected inflation. Thus, risk premium analysis must account for expected inflation in the future. That is, the underlying rate of inflation and conditions of the historical period over which risk premia are estimated must match those of the expected conditions of the relevant period over which the common equity recommendation is being applied, and over which retail electricity prices are being set.

²¹ Size-related risk premia are, as a general rule, relevant within the context of the Capital Asset Pricing Model. Specifically, the CAPM-based estimates of market returns appear to systematically understate the cost of equity capital for small-sized stocks. Size-related risk premia may not be relevant or appropriate in other model contexts.

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SIZE PREMIUM: Size Premium refers to the differences in cost of equity estimates attributable to differences in the underlying size of entities. Size is typically measured by equity market capitalization though other size metrics are available. Evidence drawn from capital markets of North America and Europe clearly demonstrate that as measures of size such as market capitalization declines, cost of capital increases.²² Size premia are revealed with cost of capital valuation tools and realized market returns. That is, when gauged over extended years, more or less all viable cost of capital metrics including realized returns, CAPM, DCF (where applicable), and factor models of various specification suggest that cost of capital is inversely related to the size of the firm.

A second and arguably more serious issue is estimation error: the cornerstone of modern financial economics, CAPM, appears to systematically understate the estimated cost of capital, compared to realized historical returns over the long term. Valuation tools including CAPM, and also variations of Arbitrage Pricing Theory (APT),²³ demonstrate that size differences obtain differences in capital cost rates. The market-based risk metric in the case of CAPM, Beta, rises significantly as the capitalization of the exchange-listed firms declines. Additionally, measures of size when coupled with other explanatory factors, explain differences in realized returns better than CAPM, estimated in isolation. Whereas CAPM appears to capture differences in the cost of capital in the case of both large-and moderately-sized firms, CAPM understates the cost of capital for comparatively small-sized entities.²⁴ Below are estimates of CAPM bias and the implied adjustment.

²² For determining size premia, the well-known financial services firm, Duff and Phelps, has extended the original work of Ibbotson Associates using sized based on market value (1976) to include several other size metrics including book value, net income, total invested capital, total assets, EBITDA, sales, and number of employees.

²³ Reference the analysis underlying the widely applied three-factor APT model constructed by Fama-French in recent years. Reference the Ibbotson Associates *SBBi Report*, published by Morningstar, 2013.

²⁴ *2017 SBBi Yearbook*, Roger Ibbotson, published by Duff & Phelps, pages 7-15.

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**SYSTEMATIC UNDERSTATEMENT OF COST OF CAPITAL:
DIFFERENCES BETWEEN REALIZED RETURNS AND CAPM ESTIMATES²⁵**

Portfolio Rank by Size	Average Book Value (\$M)	Realized Market Return (%)	Risk Premium Above Risk Free Rate (%)	CAPM Beta, 1963 Forward	Estimated CAPM Risk Premium (%)	Risk Premium above CAPM (%)	Attenuated Risk Premium above CAPM (%)
1	67,532	12.78	6.32	0.78	3.93	2.39	0.98
2	21,719	11.91	5.45	0.84	4.23	1.23	1.68
3	14,074	12.93	6.47	0.92	4.64	1.83	1.95
4	9,200	14.32	7.86	0.90	4.52	3.35	2.22
5	6,875	13.42	6.96	0.98	4.94	2.02	2.40
6	5,488	14.09	7.63	1.01	5.05	2.58	2.54
7	4,590	14.90	8.44	1.04	5.21	3.22	2.65
8	3,716	13.01	6.55	1.07	5.38	1.17	2.78
9	3,112	14.01	7.55	1.12	5.64	1.91	2.89
10	2,586	14.45	7.99	1.07	5.39	2.60	3.01
11	2,266	14.48	8.02	1.08	5.43	2.59	3.09
12	2,012	14.39	7.93	1.10	5.55	2.39	3.16
13	1,751	16.25	9.79	1.07	5.36	4.44	3.25
14	1,500	14.57	8.11	1.17	5.86	2.25	3.34
15	1,303	15.60	9.15	1.12	5.63	3.52	3.43
16	1,174	16.63	10.17	1.17	5.88	4.29	3.50
17	1,030	16.28	9.82	1.18	5.93	3.89	3.58
18	861	16.50	10.04	1.17	5.86	4.18	3.69
19	711	15.17	8.72	1.26	6.35	2.36	3.81
20	577	15.22	8.76	1.25	6.25	2.51	3.94
21	479	19.29	12.84	1.22	6.14	6.70	4.05
22	385	15.90	9.44	1.21	6.07	3.37	4.19
23	303	17.21	10.76	1.26	6.31	4.44	4.34
24	207	17.89	11.43	1.27	6.37	5.07	4.57
25	76	18.68	12.22	1.25	6.29	5.93	5.19

Moreover, estimation error appears to increase progressively as size declines. Absent estimation error, cost of capital studies would need to merely align the size of sample firms to that of the investment option under investigation. The cost of capital conducted for firms of approximately equivalent size would capture size premia, and the issue would be closed. The challenge is, for CAPM analysis, incorporating adjustments to the inherent, systematic bias in estimates of the cost of capital.

There are several plausible explanations for CAPM bias. As intuition suggests, small firms have smaller moats,²⁶ and are typically more vulnerable to the intrusion of competition than larger firms. In addition, larger-sized firms have advantages in the form of economies of scope, market power, access and more specialized and higher quality resources, lower vulnerability to recessions and potential loss of individual

²⁵ Reported by Duff & Phelps, *U.S. Guide to Cost of Capital*, 2017. The work of Ibbotson with respect to size premia has a long history, including annual updates of size premia estimated for market portfolio deciles in lieu of the more granular delineation of market portfolios shown in the table below.

²⁶ The notion of a “moat” is attributed to Warren Buffett and refers to the degree that a business is vulnerable to market entry by competing entities. A firm with a fairly wide moat suggests that the firm is comparatively insulated from competition.

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customers (lower business risks). Smaller firms draw upon a narrower range of resources than larger firms and are less able to form economies of scope. Further, comparatively small firms are less able to realize scale economies in the processes of product development, in the production of goods and services, in administrative support functions, and in marketing. Finally, smaller firms are unable to diversify risks, both in terms of the range of geography and products and services.^{27, 28}

Finally, small entities have much less trading activity; lower levels of liquidity continue to be an overarching factor.²⁹ As an example, real-world analysis demonstrates that smaller entities are comparatively non-synchronous with overall markets.³⁰ Whereas the share prices of larger entities tend to mirror movements in overall equity markets, small entities have fairly high sensitivity to market movements during subsequent periods—captured as non-synchronous CAPM. This suggests that investors and business media follow contemporary developments (innovation in the form of new information) regarding larger entities more closely than for smaller entities. Further evidence is variation in estimated CAPM Beta, and other risk metrics also. Generally speaking, the various market-related risk metrics for smaller entities—such as CAPM Beta, size-related regression coefficients, and variance in overall market returns—tend to be greater than the counterpart measures for larger entities.

This body of accumulated empirical evidence has two implications for the application of cost of capital estimates to the financial assets of specific entities, such as SCV. First, where the estimates are drawn from a sample of exchange-traded entities which are either larger or smaller than the investment(s) of interest, the CAPM-based estimates can be adjusted. Second, where CAPM cost of capital estimates are applied to comparatively small-sized entities, it may be appropriate to incorporate size premia to account for the differences between the capitalization (or book value) of the sample entities and the entity for which the cost of capital is being applied. This approach provides the basis to account for systematic

²⁷ Reference Rolf Banz, “The Relationship Between Return and Market Value of Common Stocks”, *Journal of Financial Economics*, 1984. While Banz notes the differences, it is not clear whether size or

²⁸ Reference “Sizing Up the Size Premium”, Gerstein, Fisher & Associates Inc., Summer 2015.

²⁹ Reference Roger Ibbotson, Zhiwu Chen, Dan Y.-J. Kim and Wendy Y. Hu, “Liquidity as an Investment Style”, *Financial Analysts Journal*, 2013.

³⁰ Non-synchronous CAPM Betas was examined by Myron Scholes during the 1970s and has been subsequently explored by others. Reference R.J. Grabowski and D. King, “New Evidence of Size Effects and Equity Returns”, *Business Valuation Review*, September 1996 and September 1999, both revised March 2000.

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understatement of cost of capital estimates of the implicit discount rate harbored by investors in the firm—in this case, SCV.

The incorporation of size premia within the market-based estimates of the cost of equity of invested equity capital in SCV is facilitated via additional risk factor, stated in percentage points (basis points).

LEVERAGE: Leverage refers to the financing of assets, the cumulative value of investment net of capital depletion, with borrowed money, or debt. Leverage is a matter of degree: a progressively larger share of assets financed with debt is referred to as higher leverage. Leverage metrics include debt capitalization ratio (debt ratio), the quotient of debt outstanding divided by total capitalization; and the debt ratio divided by the capitalization ratio of common equity (debt/equity ratio). Higher leverage translates into increased risk and thus higher cost rates, for both debt and equity. This result follows directly from business risks inherent to the firm, measured as the statistical variation in operating income. By this measure, 10% variation in operating income translates into 10% variation in return on common equity, absent leverage (normalized by the amount of equity and debt outstanding). In the presence of debt or, further, comparatively high levels of debt within total capital—say, 70%—differences in realized operating income translates into much higher normalized variance in the return on equity, as well as debt.

The first formal recognition of the cost of capital leverage was that of Franco Modigliani and Merton Miller (M&M).³¹ Because of the sensitivity of the cost of capital to the degree of leverage, it is appropriate to adjust estimates of the cost of equity to account for leverage differences. Accordingly, the cost of capital estimates obtained within this study are adjusted in accordance with Miller and Modigliani's *Capital Structure Theorem*, Proposition II. Because capital structure, in particular equity participation, affects the market value of the firm in question, this study must consider equity participation in evaluating cost of capital for SCV.

The original Propositions I and II of M&M have been challenged and are not generally accepted because fundamental conditions are violated by market experience. In the case of SCV, corporate taxes are not present; however, investors and corporate entities cannot necessarily borrow at the same cost rate, and transactions costs are inherent to financial contracts; institutional restrictions on borrowing exist, and the prospect for bankruptcy and commensurate losses to shareholders appears to rise as the share of debt

³¹ Franco Modigliani and Merton Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment", *American Economic Review*, 1958.

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risers.³² Nonetheless, it is appropriate to accept the conceptual underpinnings inherent in M&M,³³ though the M&M framework has been challenged, with the results shown to not hold under real work conditions. Generally speaking, comparatively “thin” equity participation within total capital increases the cost of equity; higher participation places downward pressure on the cost of equity. In summary, the market cost of debt and equity both rise with respect to lower equity participation.

CURRENT CONDITIONS OF FINANCIAL MARKETS

A company’s cost of capital varies across regions and macroeconomies where, to a substantial extent, expectations are formed by private and institutional investors from both the long-term history and recent developments. The investment community takes account of macroeconomies and the prospects for growth in economic activity, fiscal policy concerns, and monetary policy as it impacts on inflation and real interest rates over the near-term future.

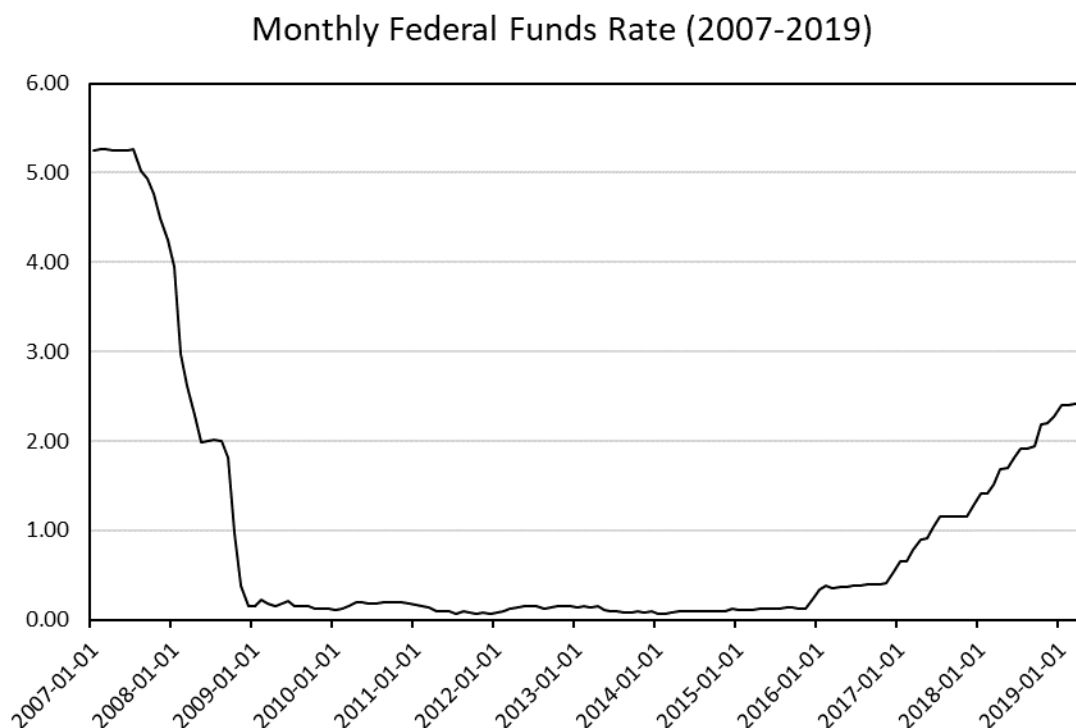
In particular, U.S. monetary policy is geared to the maintenance of overall price stability and moderation of variation in economic output across business cycles. To achieve this goal since the financial crisis of 2008, low interest rates have dominated the monetary policy landscape of the United States and Federal Reserve policy. The Federal Reserve maintained interest rates at near-zero percent between 2009 and 2016. Since then, the Fed has assumed a gradual, tentative approach to inch interest rates higher, though the current federal funds rate sits at approximately 2.4% which is relatively low by historical standards. The graph below shows the federal funds rate over time since the beginning of the last decade’s recession.³⁴

³² The traditional view regarding capital structure accepts that a judicious use of leverage can lower the cost of capital, and that beyond some normal range of debt leverage the overall cost of capital rises. This result comes about because the increases in the cost rates for debt and equity outweigh the impacts of the increase in the share of debt. In fact, this is the result and the reason that, over the relevant range, simulations suggest that the weighted average cost of capital for SCV declines ever so slightly with increased debt as the debt share rises from approximately 48% to 56%, holding the embedded cost of debt unchanged.

³³ That is, CAPM betas can be adjusted in order to recognize the implied differences in capital risks, for differences in leverage. Reference Robert Hamada, “The Effect of the Firm’s Capital Structure on the Systematic Risk of Common Stocks”, *Journal of Finance*, May, 1972. This concept provides the foundation to infer unlevered betas, referred to as asset betas. Once calculated, asset betas can then be used as the basis to determine the implied changes to the cost of capital, within a CAPM framework, as a result of changes to equity participation. The reason for utilizing a general formulation that simulates leverage impacts on cost of capital based on the elasticity of the cost rate with respect to leverage, in lieu of the Hamada adjustment to CAPM beta, is that the estimated betas do not appear to consistently conform to the theory.

³⁴ Data from the Federal Reserve Bank of St. Louis (FRED).

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To further support the slow recovery of the U.S. economy following the Great Recession (beginning late 2007) the Federal Reserve dramatically expanded its balance sheet, facilitated by Quantity Easing monetary policy. In essence, the U.S. Federal Reserve has expanded money supply with the intent of perturbing an expanding macroeconomy and raising employment.

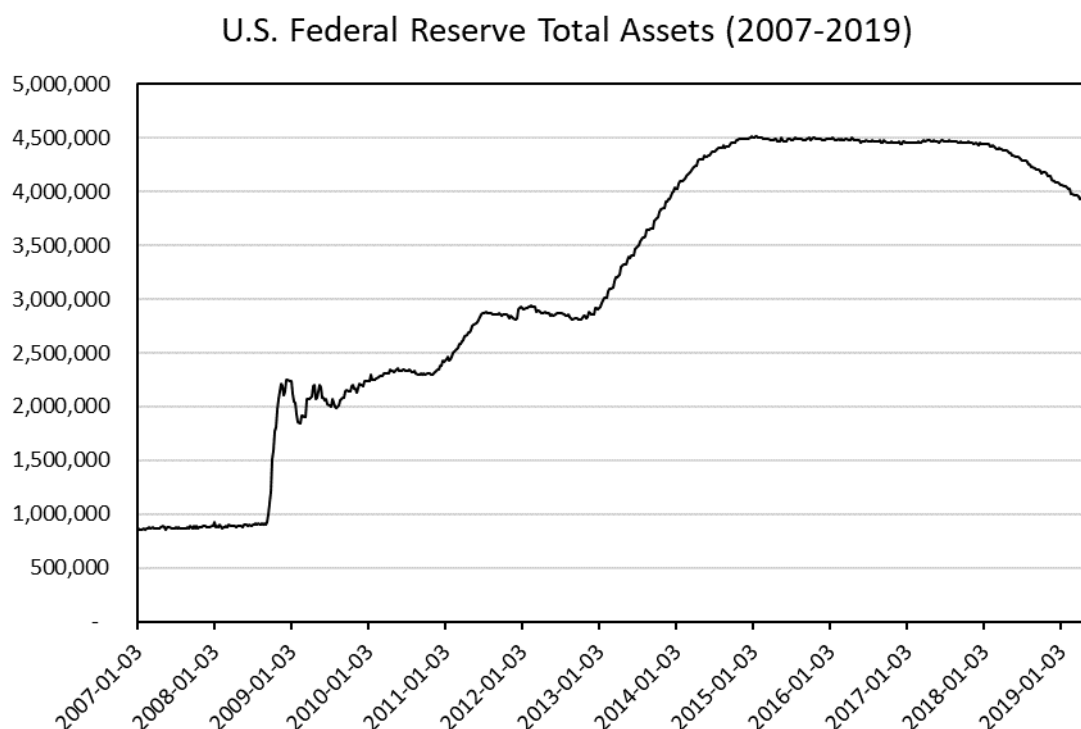
Before the crisis, the Fed’s balance sheet was roughly \$870 billion dollars, or about 7% of GDP. This size largely reflected the amount of currency in circulation, which was by far its biggest liability at the time. As the economy continued to weaken and with financial markets impaired, the Fed bought longer-term assets such as 10-year bonds from the Treasury, commercial paper, and mortgage-backed securities from government agencies and financial entities operating in wholesale financial markets. To pay for these assets, the Fed credited the accounts of the sellers’ banks at the Fed, thus increasing those banks’ reserves. By 2015, the balance sheet had more than quadrupled in size. The Federal Reserve states that, because of high demand for currency brought on by the longest economic expansion in United States history, its balance sheet will not see a substantive decline in liabilities in the near term.³⁵

³⁵ See Federal Reserve Board of San Francisco “Economic Letter”, June 3,2019.

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At this point, the U.S. Federal Reserve is expected to hold monetary policy steady, facilitated by setting the interest rate on overnight reverse repurchase agreements, the rate at which the Federal Reserve pays member banks on the bank reserve deposits that it holds. As alluded to by recent statements of policymakers, the Federal Reserve may lower the federal funds rate somewhat in the near-term, should the U.S. economy tend to slow.

Expectations of interest rates on federal funds over near-term months and years, as well as the long-term future, determines the interest rates on long-term U.S. Treasury securities, including 20- and 30-year bonds of constant maturity. Shown below, the yield curve on U.S. Treasury securities is unusually flat, suggesting that investors anticipate short term interest rates will remain more-or-less unchanged over the foreseeable future.

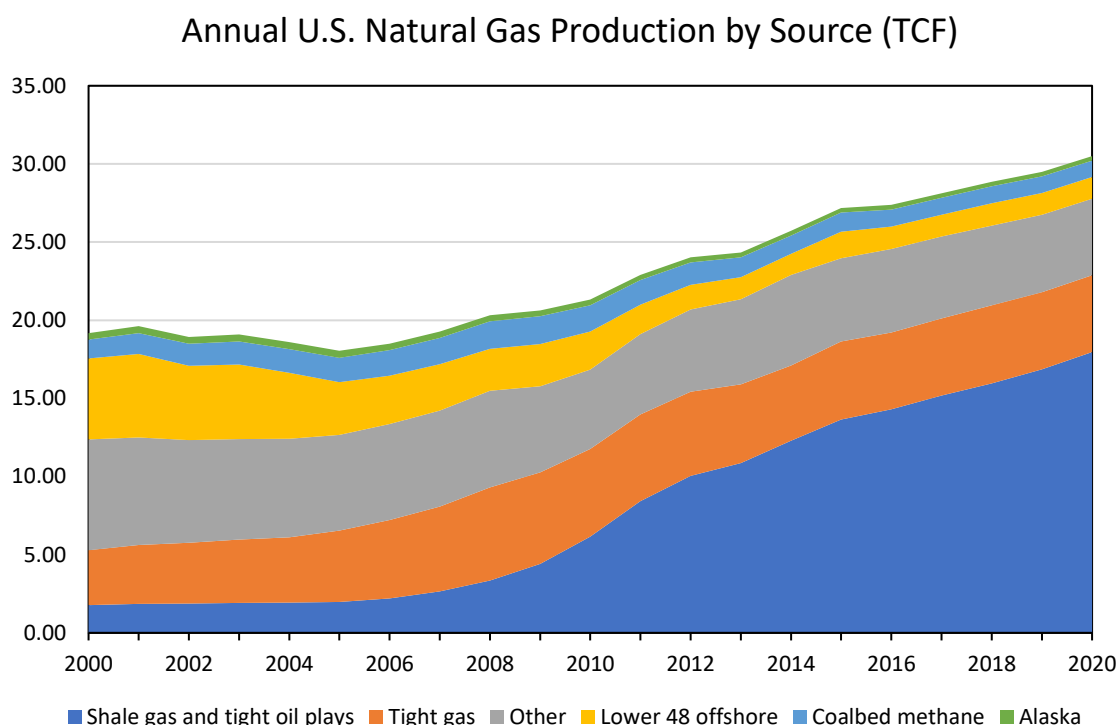


RISKS AND OPPORTUNITIES IN NATURAL GAS DISTRIBUTION

Since the turn of the 21st century, technological advances in oil and gas drilling has led to a supply boom in natural gas throughout the United States. Hydraulic fracturing techniques like horizontal drilling has facilitated commercial production volumes of shale gas in the Barnett Shale play of northern Texas, and, subsequently, producers have developed other shale formations in eastern Texas and north Louisiana, the

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Woodford in Oklahoma, the Eagle Ford in southern Texas, and the Marcellus and Utica shales in northern Appalachia.³⁶ This has generated an influx of cheap natural gas into the United States economy. The boom can be seen clearly in the graph below, which illustrates data from the Energy Information Administration (EIA) on total production of natural gas.³⁷ Around 2010, shale gas erupted as the country's primary source of natural gas, and ever since, natural gas production has increased on an aggregate basis each year.



Technological improvements in distribution infrastructure have also incentivized the build-out of a more extensive natural gas pipeline grid in the United States. For example, the widespread switch from steel to plastic distribution piping has led to cost decreases, as well as quality increases. Plastic is more durable than steel or copper because it does not corrode and needs no anticorrosion protection, and when buried with a tracer wire, it can be located as easily as metallic pipe.³⁸ As a result of such improvements, in conjunction with the influx of natural gas described above, pipeline construction has accelerated in the past decade, both for long distance transmission and for local distribution.

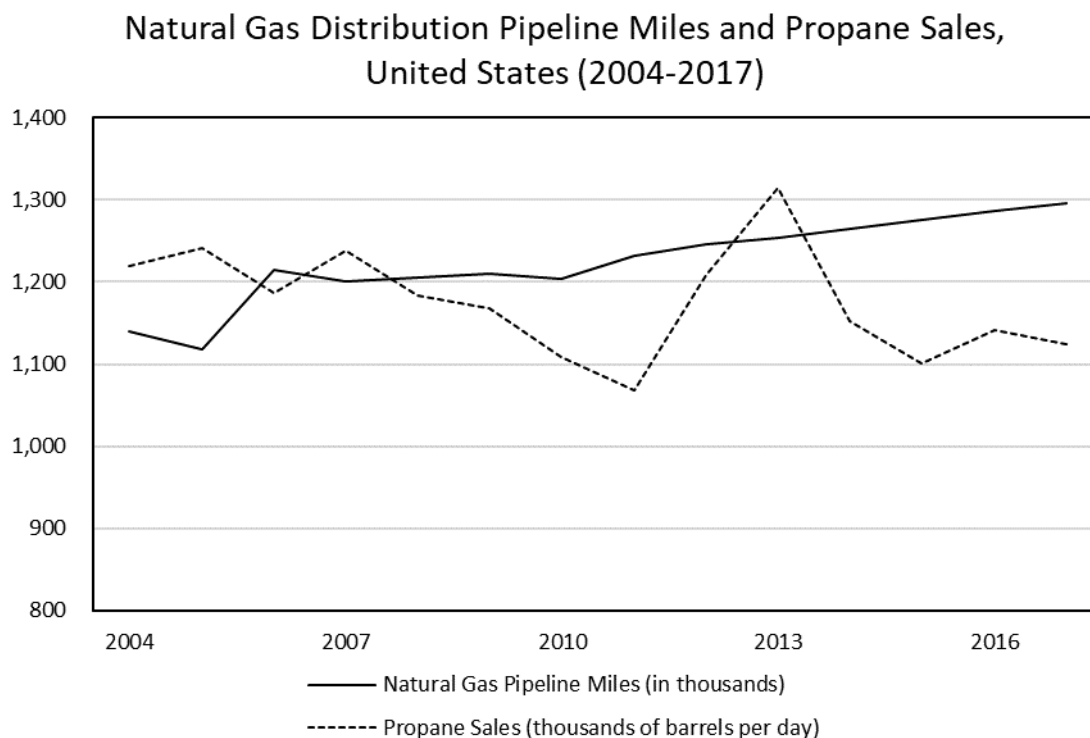
³⁶ Energy Information Association, *Basics*.

³⁷ Energy Information Association, *Annual Energy Outlook (2016)*

³⁸ Fire Engineering, *Construction Concerns (2007)*

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As distribution pipelines proliferate to less urban regions, natural gas has taken market share away from propane as the primary heating source of rural households. Since 2004, winter consumption of propane has steadily declined nationwide, on average, thanks to pipeline grid improvements and fracking, which has made natural gas more economical.³⁹ The graph below depicts the expansion of natural gas distribution pipeline mileage over the past two decades, along with propane sales that have declined, on average, since 2004.⁴⁰



Perhaps the most pressing expenditures among gas utilities as the distribution grid expands are the enhancement of infrastructure safety. Natural gas utilities spend \$22 billion annually to improve distribution and transmission safety, installing updated plastic lines at a rate of 30,000 miles per year.⁴¹ This investment has led to a decline of approximately 40% in pipeline accidents over the past decade. This emphasis on safety dramatically improves the wellbeing of ratepayers, but also constitutes a major expense for natural gas distribution utilities.

³⁹ Data from the Energy Information Association.

⁴⁰ Data from the American Gas Association.

⁴¹ See American Gas Association, *Pipeline Safety*.

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COST OF EQUITY—STUDY RESULTS

Selection According to Comparable Risks

The starting point for estimates of the cost of capital is the universe of equities listed with U.S. capital markets as a starting point from which to select comparable risk peer group of utilities and non-utility companies. Once selected, the cost of common equity is estimated for the sample companies. A distinguishing factor of comparability is market size. As discussed above, empirical evidence convincingly demonstrates that the cost of capital rises as the relative capitalization of firms declines, other factors held constant.

The cost of equity study draws heavily, though not exclusively, upon data and information sources including Value Line, Duff and Phelps, Ibbotson Associates (Morningstar), and the web-based services of Yahoo Finance, UBS Financial Services, and Zacks Financial Services. For the selected entities, an array of financial data, business descriptions and classifications, official financial results, historical price experience, and various diagnostic statistics of interest are reported by these data sources.⁴² The common equity shares of the comparable risk entities including utility and non-utility companies are traded on the New York Stock Exchange and the NASDAQ exchange.⁴³ The equity listings of NYSE and NASDAQ clearly do not constitute the full set of investment possibilities. Indeed, approximately 75 stock exchanges currently exist worldwide and, arguably, some combination of the Morgan Stanley Capital Markets (MSCI) plus exchange indexes of the North American equity markets is a more complete view of world equity markets, when assessing the performance of equity markets at a summary level, which is arguably necessary in the case of CAPM, Risk Premium, and also Arbitrage Pricing Theory-based methods. Nonetheless, NYSE and NASDAQ listings constitute large shares of worldwide equity markets, along with commensurate levels of transaction liquidity. Movements and performance of the indexes for the North American markets often parallel movements share prices of other world indexes, though differences are observed as a result of currency exchange rate movements, unanticipated random social and physical events within regions, and significant changes in expectations of economic performance within regions.

⁴² As an example, the *Value Line Investment Survey* publishes several commonly applied financial indicators including Financial Strength, Price Stability, Price Growth Persistence, and Earnings Predictability which presumably gauge the comparative risks of exchange listed entities. Other financial services firms including Morning Star, Charles Schwab, Thomson Reuters, Argus, Credit Suisse, Ned Davis Research, CFRA, and Market Edge provide qualitative assessments and numerical ratings to listed entities to gauge the investment worthiness.

⁴³ The NASDAQ exchange evolved from the over-the-counter trading procedures put in place by the National Association of Securities Dealers in years past.

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Furthermore, the North American markets, unlike worldwide exchanges, carry equity listings for numerous utility companies.

From the U.S. market portfolio, we develop two utility company samples and a comparable risk non-utility sample. The first utility sample is referred to as the *Gas Distribution Utilities*, and is composed of retail natural gas service providers in the U.S. The second sample, *Moderate-Sized Electric Utilities*, is limited to retail electricity service providers that have modest yet significant levels of market participation and, as a matter of business line, retail electricity services is similar to gas distribution services. Our studies demonstrate that, as a practical matter, the level of capital risks and thus the opportunity cost of capital is comparable for the two samples. For purposes of determining the equity rate of return requirements of SCV, the study also draws a third U.S. sample, referred to as *Comparable Risk Non-Utility Companies*.

The cost of capital methods used herein, coupled with evidence from international cost of capital studies, suggest that, particularly for contemporary capital markets with high levels of international capital flows, observable market and financial risk metrics are the predominant selection criteria. Line of business appears to have only a modest level of relevance to cost of capital, once market and financial criteria are satisfied. Thus, it is appropriate, for determining the allowed return on equity, to draw samples from a broad range of business fields once comparable risk criteria are satisfied. Nonetheless, the cost of capital study also utilizes two common business-line samples (utility samples 1 and 2), thus adhering to standard regulatory practices, in addition to developing cost of equity estimates for a separate sample of low-risk non-utility entities.

MODERATE SIZED GAS UTILITIES: A sample is first drawn on the basis of market liquidity and business line. The selected gas distributors are shown on Exhibit 4. It is virtually impossible, these days, to assemble a sizable set of electric companies that are exclusively retail electric utilities—sometimes referred to as a *pure play*.

The initial set of natural gas utilities and energy companies includes 19 entities. From this initial draw,⁴⁴ 7 gas distributors are retained by selection 1. As shown, the gas distribution utilities range from approximately \$200 million (Delta Natural Gas Company) to well over \$6.0 billion (Atmos Energy

⁴⁴ The U.S. natural gas industry includes many regional and national distributors of liquid propane and specialty industrial gas products and services, such as Penn Octane Corporation, Suburban Propane Partners, and Continental Fuels Inc.

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Corporation). Results of selection screen 2 for gas distribution utilities (Exhibit 4) reveal greater variation according to statistical variation in EPS as well as equity participation in capital. Note that Delta Natural Gas is not included in the final sample, reached in selection 2. Because of the comparatively small size of the gas utility sample, the defined criteria are not strictly adhered to. Specifically, the variation in market returns for Chesapeake Utilities is significantly above the average, a consequence of the exceptionally high earnings growth obtained through gained in market share over recent years.

The mean-variation *theory* on which the Capital Asset Pricing Model rests suggests that risk metrics other than CAPM Beta do not matter for the determination of portfolios that efficiently trade off risks and potential future return levels. However, empirical *evidence* suggests that a) internal financial metrics such as items 1-3 above are also utilized by investors to value equities, and b) CAPM theory (as with other capital market theories) does not necessarily explain historical market returns particularly well. Thus, it appears that, to a substantial degree, information other than CAPM Beta is also relevant to investors in the valuation of equities.

MODERATE-SIZED ELECTRIC UTILITIES: Turning to the moderate-sized U.S. Electric Utilities, the selection process is similar to methodology used to determine Gas Distribution Utilities. That is, the determination of the first sample of mid-sized electric utilities involves two steps. The first step involves an initial screen of utilities according to the predefined selection criteria. As mentioned, these criteria are as follows:

- *Liquidity:* companies that are of modest size but have sufficient market presence and participation to ensure sufficient market activity and transaction volume;
- *Business Line:* companies whose primary business line is retail electricity services; and,
- *Reasonably consistent financial performance.*

To determine U.S. this sample, the study begins with 42 moderate-sized entities within the U.S. electric utility and electric energy companies. From this initial selection, 16 electric utility companies are selected for potential use in cost estimation. Market and financial cost measures for the electric utilities are presented on Exhibit 4.⁴⁵ Some of these 16 companies have involvement in non-electric retail business lines including natural gas.

⁴⁵ The increased openness of U.S. electricity markets in recent years, including market entry as well as relaxation of financial restrictions, has resulted in an expanded range of business activity. Over recent years, entities within the U.S. electricity services industry have been, or are currently, involved in oil and gas exploration (MDU Resources), real estate (Pinnacle West), and renewable energy resources (Allete).

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However, electric utilities comprise entities where electric power supply and delivery is the dominant share of business activity. Non-utility activities should not matter in a measurable way, providing that such activities are of modest scale; indeed, endeavors to diversify risk over alternative business lines may reduce variation in earnings, variation in internal cash flow, and variation in market returns, thus reducing overall investment risk and the cost of capital. As revealed on Exhibit 4, electric utilities range from less than \$1.3 billion (Otter Tail) to over \$16.0 billion (Eversource Energy) in total capitalization, with similar differences in operating revenues and total net plant.

From this initial set of 16 companies, selection draw 2 including electric utilities that satisfy size criterion and comparable risk criteria, as follows:

- *Equity Participation in Total Capital*;
- *Variation in Earnings per share (EPS) over five and ten years;*⁴⁶
- *CAPM Beta* which, as discussed above, is the ratio of the covariation of the market returns of a specific stock of a company and the market as a whole, and the statistical variance of the returns of the market; and,
- *Variation in Market Returns measured as the* coefficient of variation in monthly market prices.

Three electric utilities in the selection 1 draw (Exhibit 4) including CMS Energy, Eversource Energy, and SCANA⁴⁷ are large, and are thus excluded from the selection 2 draw. For the sample, individual electric utilities fall within one standard deviation of the sample average, for the several criteria—the exceptions include PNM Resource for *Variation in EPS* over 10-years and market returns, and MGE Energy with respect to equity participation in total capital (equity ratio). It is these utility companies that, by this arguably objective approach, satisfy the criteria of comparable risks and thus the U.S. Supreme Court guidelines regarding fair rate of return contained within the *Bluefield* and *Hope* decisions. While moderate in size by U.S. standards, the electric utilities are nonetheless sizable compared to SCV.

NON-UTILITY COMPANIES: The sample of comparable risk non-utility companies is drawn from across all non-utility economic sectors. The initial selection criteria were equity market capitalization of less than \$3.0 million USD, some level of debt carried within the balance sheet, CAPM Beta range of 0.60 – 0.95, and legacy, captured by the availability of public domain financial data over ten years. These criteria

⁴⁶ As shown, the coefficient in earnings per share can vary widely as a result of specific earnings events (Black Hills, El Paso, and OGE Energy).

⁴⁷ Also, SCANA is the primary sponsor of a major central station nuclear power plant (V.C. Summer Units 1 and 2). The project has been recently cancelled, after accruing over \$10 billion in capital expenditures.

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resulted in the selection of 127 entities from well over 3,000 U.S. exchange-listed firms, where the selected firms include food markets, pipe manufacturing, financial services, health services, and a military equipment manufacturer. The application of a random selection procedure culled 17 entities⁴⁸ from the set of 127, and ultimately yielded a total of 15 entities with an average capitalization of \$431 million. The selection screen 2—equity participation, CAPM beta, variation in market returns, and variation in earnings per share (internal business and financial risk)—provides risk profiles for these 15 companies, which together constitute the comparable risk non-utilities, and are shown on Exhibit 4.

Non-utility companies have, arguably, similar risk characteristics to that of the U.S. electric and gas utilities. However, significant differences can be observed for the several measures including equity participation, variance of market returns and internal returns to capital (EPS). High levels of variation reflect much larger year-over-year variance in revenue flows, and changes in the outlook by investors—typical of smaller exchange-listed companies. However, CAPM betas for the non-utility companies are similar to those of the electric utilities and gas distributors. Furthermore, the non-utility companies typically have much higher levels of equity participation, and thus compensating for higher business risks.

In summary, estimates of the cost of equity capital of this study involves three samples including gas distribution companies (sample 1), moderate-sized U.S. electric utilities (sample 2), and comparable risk non-utility companies (sample 3). Market liquidity, measured by market capitalization, is a necessary selection criterion as stated above. The selection process results in comparatively small-sized electric and gas utilities that have sufficient liquidity to obtain reliable estimates of the cost of equity. Yet, the selected utility companies are substantially larger than SCV. Because the cost of equity capital appears to rise monotonically with smaller size, the implication is that the cost of equity capital estimated for the two utility samples does not fully capture the inherent capital risks incurred by investors in SCV.

Empirical Findings, Cost of Equity

The market experience of the selected entities within samples 1-3, as drawn from U.S. markets, are assessed with cost of capital models including DCF, CAPM and Realized Historical Returns, as reviewed above in detail. This first step yields estimates of the cost of equity. Cost estimates are then adjusted to reflect specific characteristics of SCV, including size premium and leverage.

⁴⁸ Incomplete or anomalous financial data, as reported, caused some randomly selected entities to be substituted with other entities from a nearby location within the total list of 127 entities from which a subset was culled.

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The return on equity recommendation follows accordingly. The estimation procedures, which begins with the selection of the comparable risk peer groups, does not explicitly take account of business context differences.

The three cost of capital methods draw on market experience over several timeframes, where timeframe is specific to approach. In the case of discounted cash flow, cost estimates reflect earnings and dividend growth over ten years ending in 2016, with market prices and dividend yields observed in May 2017. Historical market returns-based estimates are based on the realized returns from 1998 through 2016. The capital asset pricing model includes estimates of risk premium, measured as the difference between the realized returns on equity markets as a whole and long-term treasury bond yields for years 1970-2016. The study does not use equity market experience for the latter portion of 2017 and 2018 because the rapid run-up in equity values can distort cost of capital estimates, particularly for public utilities.

COMMON EQUITY COST ESTIMATES: The analysis draws on the recent and long-term historical experience as the basis to determine the cost of equity capital. The approach takes account of capital risks as well as the future prospects for capital returns—essentially, the potential for realized returns to investors, as holders of property rights claims to capital in the form of financial assets.

Estimates of the cost of equity hinge upon expectations formed by investors. Investors form their expectations regarding the future returns to capital on the basis of a broad range of information and data. The specific observed historical experience of individual utilities, as reflected in the official financial reports of various members of the two samples, are augmented by other information relevant to investors including idiosyncratic characteristics (such as investment plans), regulatory governance, and growth in sales. Further, we can be reasonably sure that the investment community takes account of macroeconomics and the prospects for growth in economic activity, fiscal policy concerns, and future monetary policy and its impacts on inflation and real interest rates over the near-term future. A given company's cost of capital varies across regions and macroeconomics where, to a substantial extent, expectations are formed by private and institutional investors from both the long-term history and recent developments.

Along with brief discussion, the cost of equity estimates are presented separately below for each of the three methods (discounted cash flow, capital asset pricing model, and realized market returns), for each of the three samples. These summary findings are further supported at a more detailed level in the several pages of the exhibits, with CAPM results shown in Exhibit 1, Discounted Cash Flow results presented in

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Exhibits 2, and Realized Returns presented in Exhibit 3. The cost of equity estimates obtained with the Discounted Cash Flow and CAPM are adjusted for issuance costs.

Discounted Cash Flow estimates of the cost of equity are as follows:

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY				
Gas Distribution Utilities				
Estimation Period	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate	Adjusted Cost Rate
Apr-May, '15	2.77%	7.70%	10.47%	10.65%
Apr-May, '16	2.52%	6.58%	9.09%	9.25%
Apr-May, '17	2.27%	5.93%	8.20%	8.35%

Moderate-Sized Electric Utilities				
Estimation Period	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate	Adjusted Cost Rate
Apr-May, '15	3.33%	6.31%	9.65%	9.86%
Apr-May, '16	3.33%	5.72%	9.05%	9.27%
Apr-May, '17	3.10%	6.08%	9.10%	9.38%

For the immediate study, the application of the Discounted Cash Flow methodology involves drawing three market samples, including the May market price experience for years 2015-2017. This multiple sample approach (covering three years) is carried out for each of the selected electric utilities and gas distributors which constitute samples 1 and 2. For each year's draw of prices, investors would have available multiple years of historical financial data including the earnings, internal cash flow, and dividend experience up through and including December of the previous year.⁴⁹

Capital Asset Pricing Model estimates of the cost of equity are shown below. As discussed above, the CAPM model involves three inputs including estimates of the risk-free cost of capital, expectations of future returns to equity markets as a whole, and CAPM beta, the ratio of the covariance of share prices/market to the variance of overall market returns. Consistent with theory and conventional practice, it is appropriate to match up the risk-free rate of interest with the duration of investment undergoing capital valuation. The physical facilities of SCV, like those of all gas distributors, are unusually long-lived. Accordingly, for the cost of capital study, the risk-free rate is set equal to the forward-looking dividend yields on 30-year U.S. Treasury Securities (constant maturity). Specifically, the risk-free rate is equal to the

⁴⁹ For example, the market price experience for May of 2015 would reflect expectations, by investors, of the future returns to capital, based on historical data through year end 2014 as well as other relevant information.

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average monthly yield on 30-year U.S. Treasury securities (constant maturity) for two timeframes including January 2009 through July of 2017, and January 2013 through July of 2017.

Estimates of future returns for equity markets (i.e., overall market return) is based on historical realized returns for U.S. markets, measured in real terms. Once estimated, the observed real rate of return for equity markets is adjusted upwards for expected inflation of 1.8%. Real rates of return are calculated as the arithmetic average of annual returns over two timeframes, 1970 through 2016, and 1990 through 2016.

The CAPM betas for the selected electric utilities, gas distributors and comparable risk non-utility companies are culled from the Value Line data bases. Value Line estimates CAPM betas with weekly frequency over five years, which are then adjusted for central tendency based on the methodology pioneered by Marshall Blume.⁵⁰ For this study, CAPM estimates of the cost of equity use the average of the estimated betas over years 2013-2017. CAPM estimates of the cost of equity are as follows:

(see following page)

⁵⁰ The so-called Blume methodology derives from the work of Marshall Blume, as first presented in the article, "On the Assessment of Risk", *Journal of Finance*, Vol. 26, 1971. The alternative approach to adjust the estimated raw Betas is the so-called Vasicek technique, as proposed by O.A. Vasicek in "A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas," *Journal of Finance*, vol. 28, 1973. Generally speaking, the Vasicek approach is considered the preferred methodology though considerable information is required for implementation. Commercial financial services including Bloomberg and Value Line, utilize the Blume approach, whereas Ibbotson Associates employs the Vasicek correction method.

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CAPM ESTIMATES OF THE COST OF EQUITY

	Cost Rate, Adjusted for Issuance Cost	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk-Free Rate
Gas Distribution Companies						
Low	8.24%	8.08%	3.20%	0.71%	10.04%	3.20%
High	9.20%	9.20%	4.50%	0.74%	10.94%	4.50%
Weighted Average	8.86%	6.90%	3.32%	0.75%	10.49%	3.32%
Moderate-Sized Electric Utilities						
Low	8.50%	8.33%	3.20%	0.75%	10.04%	3.20%
High	9.57%	9.39%	4.50%	0.79%	10.94%	4.50%
Weighted Average	9.15%	8.97%	3.32%	0.79%	10.49%	3.32%
Comparable Risk Non- Utility Companies						
Low	8.82%	8.65%	3.20%	0.80%	10.04%	3.20%
High	10.32%	10.12%	4.50%	0.89%	10.94%	4.50%
Weighted Average	9.84%	9.65%	3.32%	0.88%	10.49%	3.32%

Realized Market Returns are wholly consistent with fair rate of return statutes and law, and are not burdened with the circularity arguments of using realized book returns as the basis for determining authorized returns across regulatory authorities. Otherwise referred to as *historical returns* or *comparable earnings*, realized returns serve as plausible estimates of the cost of equity, providing that the returns reflect competitive financial market experience with adequate liquidity, and second, are measured over an appropriate timeframe. For this study, realized returns are reported for the three samples including electric utilities, gas distribution companies, and comparable risk non-utilities. Market returns include dividends in the case of the electric utilities and gas distributors (samples 1 and 2). However, dividends are not incorporated in the analysis for the non-utilities, as the dividend experience is inconsistent across the selected companies of the sample.⁵¹

The realized market returns for the non-utilities may be somewhat higher than the implicit opportunity cost of equity for the 2007-2016 timeframe insofar as the starting point reflects the 2009 nadir of the economic recession across Western Economies, particularly for the U.S. As consequence, many small non-

⁵¹ It is nonetheless arguably appropriate, despite the inconsistent dividend experience of the selected companies, for the dividend payments to be incorporated into the study results. Dividends constitute a non-trivial component of total return. If dividends had been included within the analysis, the realized returns for the non-utility sample would be higher, by perhaps two percentage points.

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utility companies experienced large declines in market value. As a consequence, the realized market returns subsequent to this timeframe reflect, in part, the deleveraging of the financial sector and households within the U.S. With the economic recovery, many small capitalization entities listed on the NASDAQ and NYSE exchanges have realized comparatively high returns. In brief, the 13.4% realized return level, for the smaller non-utility companies, may somewhat overstate prospective return opportunities. For this reason, the cost of equity study also includes realized market returns for a second sample of comparable risk non-utilities, covering the period 1999-2007. These realized returns are referred to as *Pre-recession Results*, where the realized returns are 9.40%.⁵² Historical market returns are summarized in the following table.

HISTORICAL RETURNS FOR THE UTILITY AND NON-UTILITY COMPANIES (Samples 1-3)

Company	2007-09	2008-10	2009-11	2010-12	2011-13	2012-14	2013-15	2014-16
Gas Distribution Companies								
Average	1.9%	4.2%	11.5%	2.8%	7.3%	9.5%	10.3%	11.3%
Weighted Average	0.1%	5.1%	11.8%	5.5%	9.2%	7.8%	15.5%	15.6%
Moderate-Sized Electric Utilities								
Average	-5.4%	-0.3%	13.9%	10.6%	11.5%	12.3%	9.6%	12.0%
Weighted Average	-4.1%	1.1%	15.7%	11.7%	11.4%	13.3%	10.4%	11.8%
Comparable Risk Non-Utility Companies								
Average	4.4%	18.8%	35.6%	14.4%	13.1%	15.4%	21.1%	22.0%
Weighted Average	1.2%	9.1%	29.7%	14.6%	20.9%	21.3%	32.9%	30.9%
<i>Pre Recession Results</i>				1999-03	1999-04	1999-05	1999-06	1999-07
Average				0.0391	0.0931	0.1123	0.124	0.1153
Weighted Average				0.0344	0.0889	0.1092	0.1236	0.1158
							Gas Distributors	10.8%
							Electric Utilities	10.1%
							Non-Utility Companies	13.4%
							N-U Companies (pre-recession)	9.4%

⁵² Note that the results of the cost of equity estimates are reported on both a simple average and capitalization-weighted average basis.

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ADJUSTMENTS TO COST ESTIMATES: As discussed more fully above, the cost of equity estimates developed for samples 1-3 of small to moderate sized utilities and non-utilities are adjusted for the market context of SCV. As mentioned above, adjustments cover two dimensions: small size premia and leverage.

As previously discussed, *Small Size Premia* refers to the differences—i.e., cost rate premia—associated with comparatively small sized companies, compared to moderate-sized and larger entities. Size can be measured in several ways, though market capitalization is the general measure. As alluded to in the above discussion of size premia, it is perhaps worth noting that extensive analysis of realized returns within U.S. equity markets reveals that progressively higher equity risk premia—and, thus, cost of capital—attend small-sized companies, particularly for very small entities such as SCV. For this reason, the cost of capital estimates must be adjusted wherein estimates of the cost of equity are based on the experience of much larger markets and equity listings.

Risk premia associated with small size, sometimes referred to as small capitalization risk premia, reflect intuition, well established principles that serve as the foundation of finance theory, and the observed realities of capital markets. First, ordinary common sense would lead one to recognize that small entities face higher business risks than large entities. Higher risks attending small size come about from the principle of large numbers. Specifically, the financial impacts of random business events, which occur over the course of business enterprise, cannot be diversified by small entities as well as by large entities. Essentially, the impacts of business events within larger enterprises get absorbed within a pool of other events, both positive and negative, with the result that such events are substantially muted in their total impacts on the financial results of the enterprise.

The intuitive idea of diversification of business activity is reflected in portfolio theory. In this regard, the larger entity can be viewed as, essentially, a larger portfolio of individual business activities with the attending diversification effects, providing that individual business activities have less than perfect correlation.

Capital markets reveal that, among other factors, the variability of the total returns to capital reflected as operating income, will typically be higher for smaller entities than larger entities. Second, historical market returns for entities with smaller market capitalization will have higher variation than for entities with higher capitalization levels. Within the context of CAPM theory, the core of modern finance theory, the relevant measure of risk is the covariation of market returns of individual equities with the market as a whole, normalized by the variance of the overall market, referred to as CAPM Beta. Insofar as this notion

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of risk—*i.e.*, systematic risk—is the only relevant measure of risk given optimal portfolio theory, competitive capital markets would ensure that equities are priced at levels such that the realized market returns of individual equities would be ordered according to CAPM Betas.

Estimates of size premia are based on market experience, where the differences in the realized rates of return are measured for specific size categories. In the case of U.S. and European markets, exchange-listed entities are ordered according to size based on market capitalization and other measures including equity book value. Market returns are estimated according to each size category. The table below presents size premia for selected size groups, along with estimates of realized market returns and risk premia.

**SUMMARY OF COST DIFFERENCES ACCORDING TO ENTITY SIZE:
REALIZED RETURNS AND THE COST OF EQUITY CAPITAL**

Book Value- Ranked Market Groups	Average Book Value (\$M)	Realized Market Return (%)	CAPM Beta, 1963 Forward	CAPM Estimated Returns (%)	Attenuated Risk Premium above CAPM (%)
3	14,074	12.93	0.92	11.10	1.95
8	3,716	13.01	1.07	11.84	2.78
13	1,751	16.25	1.07	11.82	3.25
18	861	16.50	1.17	12.32	3.69
21	479	19.29	1.22	12.59	4.05
23	303	17.21	1.26	12.76	4.34
25	76	18.68	1.25	12.75	5.19

As shown, size premia not captured by CAPM estimates range from modest understatement of 1.95% for size 3 to large differences for size groups 21, 23, and 25.⁵³ Note in particular, that the average book value for the smallest size entities, listed on U.S. exchanges, is \$76 million, more than fifteen times larger than the book value for SCV.

The study, however, attenuates this across-market premium for size. Evidence suggests that size premia vary with respect to economic sector. For purposes of this study, the working assumption is that the cost of equity capital for infrastructure industries generally have lower small size premia than for most sectors. For this reason, the immediate cost of capital has attenuated size premia differences to a range of 2.48% to 3.01%, though empirical measures suggest a somewhat higher range.

⁵³ Notably, the attenuated CAPM risk premia shown understates, for most all size groups including groups 21, 23, and 25, the calculated results. Because of variation in sample results with respect the tail distributions, the analyses underlying the cost of equity estimates used herein, employ these attenuated (smoothed) size-related risk premia differences. In essence, the cost of equity study assumes a conservative path; implicitly, the cost of equity estimates for SCV are arguably understated.

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The cost of capital study assumes a conservative posture in other respects also. Empirical analysis of understated capital risk within the CAPM model structure reveals higher small size premia for the smaller size categories/groups, when size groups are ordered with respect to market capitalization. Second, the empirical estimates of size premia do not cover entities nearly as small as SCV. Presuming that size-related risk premia rises more-or-less linearly with progressively smaller size, the implicit cost of equity capital for SCV is actually higher than the study results.

Leverage adjustment accounts for the differences in the equity participation in total capital (equity ratio) between SCV and the sample utilities and low risk non-utility companies. Other factors constant, increases in the debt share in total capital will cause both the cost of equity and cost of debt to rise. The coverage of interest on outstanding debt is a fundamental concern of corporate finance, as revealed in the credit assessments of credit rating agencies. Further, it is not uncommon to find specific interest coverage requirements to be incorporated in the bond covenants of bond issuing entities.

The differences in the level of debt financing by SCV and the sample companies (electric utilities, gas distributors, comparable risk non-utility companies) is significant. Whereas SCV has financed its assets with approximately 85% common equity over recent years, the levels of debt for the sample companies is significantly less.

The study adjusts the cost of equity estimates for the U.S. sample companies, for the leverage differences between SCV and the sample. Specifically, the differences in the cost of equity (and debt) are simulated, based on the equity/debt concepts originally advanced in the late-1950s by Merton Miller and Franco Modigliani, as discussed above. Once the effects of leverage on the cost rates of debt and equity are accounted for, the total value of the firm remains virtually unchanged, consistent with the original M&M concepts. Similarly, the overall weighted average cost of capital experiences only modest impact. These results are shown below.

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**DECREMENTAL IMPACT OF LEVERAGE ON
COST OF EQUITY FOR ST. CROIX VALLEY GAS**

Sample	Debt Cost Rate (%)	Equity Cost Rate (%)	PARTICIPATION (%)		Weighted Average Cost Rate, Absent Tax Effects (%)
			Debt	Equity	
Sample 2	5.26%	13.61%	60.0%	40.0%	8.60%
	4.95%	13.06%	55.0%	45.0%	8.60%
	4.75%	12.71%	51.0%	49.0%	8.65%
	4.70%	12.63%	50.0%	50.0%	8.66%
	4.66%	12.55%	49.0%	51.0%	8.68%
	4.62%	12.47%	48.0%	52.0%	8.70%
	4.50%	12.26%	47.0%	53.0%	8.61%
	4.54%	12.54%	46.0%	54.0%	8.86%
Sample 1	4.40%	12.28%	42.0%	58.0%	8.97%
	4.36%	12.22%	41.0%	59.0%	9.00%
	4.33%	12.16%	40.0%	60.0%	9.03%
	4.22%	11.94%	36.0%	64.0%	9.16%
Sample 3	4.11%	11.74%	32.0%	68.0%	9.30%
	4.02%	11.56%	28.0%	72.0%	9.45%
	4.00%	11.52%	27.0%	73.0%	9.49%
	3.97%	11.48%	26.0%	74.0%	9.53%
	3.95%	11.44%	25.0%	75.0%	9.57%
	3.93%	11.40%	24.0%	76.0%	9.61%
	3.85%	11.25%	20.0%	80.0%	9.77%
	3.78%	11.11%	16.0%	84.0%	9.94%
	3.77%	11.08%	15.0%	85.0%	9.98%

Consistent with theory, intuition, and market evidence, the cost of equity declines steadily as leverage increases. The above simulations have COE differences declining to 11.08% (equity share = 85%) from 12.26% (equity share = 53%). The end result is a decrease of approximately 110 basis points, which is incorporated in the cost of equity estimates and our return on equity recommendations.

Further to the analysis of leverage: the study utilizes the simulated differences in the equity cost rate to determine the differential impact of SCV's cost of equity, compared to the U.S. sample.⁵⁴ This involves the calculation of the cost rate differences, as a result of debt leverage decreasing from 47% (53% equity) to 15% (85% equity). The simulated impact of this decline in leverage provides estimates of the

⁵⁴ The algorithm underlying simulated difference in the cost of equity, measured in basis points, takes account of the relative sensitivity of cost rates to leverage, measured as elasticities. For the immediate study, the simulation of leverage effects is parameterized with an elasticity of 0.20.

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decrease in the cost of equity owing to SCV’s capital structure, compared to that of the U.S. comparable risk sample entities (samples 1, 2, and 3).⁵⁵ The cost of equity decreases by approximately 110 basis points (see table below entitled “Cost of Equity Summary Results”).

Analysis Summary

Estimates of the cost of equity (COE) are determined by applying capital valuation tools including the DCF, CAPM, and Realized Returns models to the market experience of exchange listed U.S. sample companies (samples 1,2 and 3). Model results include 14 COE estimates for the sample companies. The unadjusted model results are presented as low and high bounds along with averages, and are as follows:

COST OF EQUITY ESTIMATES FOR U.S. SAMPLE COMPANIES

METHODOLOGY	Estimates		
	Low	High	Average
Discounted Cash Flow			
Gas Distribution Utilities	8.35%	10.65%	9.25%
Mid-Sized Electric Utilities	9.49%	11.31%	10.68%
Capital Asset Pricing Model			
Gas Distribution Utilities	8.34%	9.38%	8.85%
Mid-Sized Electric Utilities	8.40%	9.46%	8.92%
Low Risk Non-Utility Companies	8.82%	10.32%	9.84%
Realized Market Returns, Rolling 5-Yrs			
<u>For 1998-2007</u>			
Gas Distribution Utilities	9.48%		
Mid-Sized Electric Utilities	10.70%		
Low Risk Non-Utility Companies	9.12%		

The study is based on samples of public utilities (samples 1, 2) and non-utility entities that appear to have comparable risks. The analysis accounts for cost of equity differences between SCV and the U.S. sample entities. Inclusion of these adjustments provide all-in cost of equity estimates for SCV—essentially, the opportunity cost of capital incurred by the equity investors of SCV. The final cost of equity estimates for SCV are summarized below.

⁵⁵ Note that SCV carries substantial levels of preferred stock within its capital structure, unlike the sample of U.S. utilities (samples 1 and 2). This distinction, however, poses no difficulties for the simulation, as preferred stock is much like debt capital, and faces much less capital risk than common equity.

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COST OF EQUITY SUMMARY RESULTS

	Range	
	Low	High
COE Estimates, US Exchange-Listed Entities (9.52%)	9.07%	9.97%
<u>Adjustment to U.S. Market Cost Estimates</u>		
Size Premium	2.48%	3.01%
Comparatively Thick Equity Participation	-1.14%	-1.04%
Total	10.41%	11.93%
Average	11.17%	

The U.S. sample results yield unadjusted COE estimates ranging from 9.07% to 9.97% with a mid-range value of 9.52%. Adjustments including size premia ranging from 2.48% to 3.01% and debt leverage effects ranging from -1.14% to -1.04% are incorporated within the COE estimates for SCV, obtaining overall cost of equity estimates of 10.41% to 11.93%, with a mid-point of 11.17%.

The cost of equity recommendation follows accordingly. SCV's regulatory authority, the PSCW, should set the return on equity for SCV within the range of 11.0% to 12.0%. An authorized return at this level is in keeping with the institutional foundation for the fair rate of return including returns equivalent to that realized on investment of corresponding risks while providing for the maintenance of financial integrity and the capability to raise capital at fair terms.

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Appendix I

Present Value of Investment and Derivation of the Constant Growth and Multi-Stage Discounted Cash Flow Model (DCF)

Present Value Theory

As wages are the compensation to labor, interest is the compensation or return to savings and capital. Savings is the share of current income held back to be consumed in later periods. A unit of current consumption has greater value than an equivalent amount of consumption later. Hence, savings must obtain greater consumption later, in order to compensate for its reduced (discounted) value.

The inducement to save is interest; essentially, the accrual of interest on savings offsets the reduction in value of later consumption vis-à-vis current consumption. Without the expectation of interest, savings would be largely exhausted as consumption in the current period. Savings are invested and, over time, give rise to and constitute the accumulation of capital. Savings realize the market rate of interest. Savings and investment – and thus the accumulation of capital – rise as expected interest increases.

Returns to savings, investment, and capital can be viewed as cash flow returns, and can be stated as an annual percentage amount. Cash flows in subsequent periods forego the interest that would have accrued on earlier cash flows. Because of foregone interest, later cash flows are worth less than those of earlier periods by the amount of interest that would have been realized on the earlier flows.

Cash flows over time can be ordered with a discounting procedure commonly known as present value. Present value revalues future cash flows according to the accrual of interest that would have been realized, had they occurred in the present. Specifically, the cash flow within a time step is discounted by a factor equal to the inverse of one plus the market rate of interest, k , compounded by time – $(1/(1+k))^t$.

The present value procedure can be shown more formally as:

$$PV = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \dots + \frac{CF_n}{(1+k)^n} \quad (1)$$

or,

$$\sum_{t=1}^n \frac{CF_t}{(1+k)^t} \quad (2)$$

where,

PV = present value

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CF_t = cash flow in time t

k = market cost (rate) of interest

Hence, $1/(1+k)^t$ is the discount factor by which the cash flows at time t are reduced.

Present value analysis equates cash flows at different points in time to the present, and constitutes a fundamental principle of financial and investment analysis. Essentially, present value normalizes the cash flows at the market rate of discount.

Consider a cash flow occurring at time, $t=0$. Since the cash flow occurs in the present and, unlike the subsequent cash flows shown in (3), below, no interest is foregone and thus it is not discounted:

$$NPV = CF_o + \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n} \quad (3)$$

Presume that a savings agent, a household, invests savings. The purchase of an investment or financial asset such as securities or other liquid assets by the agent constitutes a negative cash flow – an outflow of money. It is the expectation of positive cash flows later that induces the purchase. Positive cash flows prospectively, as expected, tend to balance the negative cash outflow associated with the purchase of the asset. All negative and positive cash flows are contained in net present value, as shown in (4) below:

$$NPV = -CF_o + \sum_{t=1}^n \frac{CF_t}{(1+k)^t} \quad (4)$$

where,

NPV = net present value – i.e., the net of all positive and negative cash flows

If net present value (NPV) is positive, the investment action is “economic” in the sense that the expected positive cash flows, discounted at the market cost of capital, are greater than – or at least equivalent to – the purchase price of the asset, the negative flow.

Competitive capital markets – or the processes of market competition – seek to discover and exhaust all opportunities for positive and negative present values. That is, the *expected* NPV of investment opportunities approximates zero, given the implicit rate of discount harbored by investors. Essentially, the market value of assets is driven to its competitive level prospectively because of arbitrage inherent to competitive markets. Market forces bid prices up in the presence of expected positive returns (NPV), or bid prices down if negative returns are expected. The discounted positive cash flows equate to and balance the purchase cost of the asset, as shown in (5), below:

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$$CF_o = \sum_{t=1}^n \frac{CF_t}{(1+k)^t} \quad (5)$$

In market equilibrium, then:

$$P_o = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \dots + \frac{CF_n}{(1+k)^n} \quad (6)$$

$$P_o = \sum_{t=1}^n \frac{CF_t}{(1+k)^t} \quad (7)$$

where,

P_o = market price at time $t=0$

The market cost of capital implicitly incorporates investor's perceptions of risk and expectations about inflation over the life of future cash flows. It is straightforward to solve for the market cost of capital, k , as we are confronted with one equation and one unknown value. For example, to solve for the internal rate of cost of a debt obligation of a borrowing firm, such as bond, simply determine the internal rate of discount that equates the positive cash flow occurring at time zero, CF_o , and the negative flows, $-\sum CF_t$, which represent the annual interest cost and retirement of the principle. The discounted negative cash flows from the perspective of the borrowing firm can be shown as $-\sum CF_t/(1+k)^t$. The analysis problem for lenders is precisely the same except that the signs attending the cash flows are reversed. Hence, the rate of discount is both the opportunity cost of capital to investors, given market arbitrage, and the cost of capital to the borrowing firm.

Constant Growth Discounted Cash Flow

For equity capital, investors' expected earnings reflect expectations of future cash flows associated with shares of stock, and thus determine the stock price currently. Assume that investors expect earnings, E_t , and dividends, D_t , to grow at some constant rate, g , over the future, such that:

$$E_t = (1+g)E_{t-1} \quad (8)$$

$$E_1 = (1+g)E_o$$

$$E_2 = (1+g)E_1 = (1+g)^2 E_o$$

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***(Confidential Work Product;
Not for General Circulation)***

$$\begin{aligned} &-- \\ &-- \\ E_n &= (1 + g)^n E_o \end{aligned}$$

Dividends of course are a function of earnings and therefore represent, along with price appreciation, the discounted cash flows. Dividends can thus be shown similarly to that of earnings, as below:

$$\begin{aligned} D_t &= (1 + g) D_{t-1} & (9) \\ \text{i.e., } D_1 &= (1 + g) D_o \\ D_2 &= (1 + g) D_1 = (1 + g)^2 D_o \\ &-- \\ &-- \\ &-- \\ D_n &= (1 + g)^n D_o \end{aligned}$$

Further, assume that dividends, D_t , are a fixed share, m , of earnings, E_t , such that:

$$D_t = mE_t \quad \text{and,} \quad D_t / E_t = m \quad (10)$$

From equation (8), then:

$$D_t = m(1 + g) E_{t-1} \quad (11)$$

$$\text{and,} \quad D_n = m(1 + g)^n E_o$$

Restating equation (7) to represent dividends as a fixed share of earnings which are paid out, provides:

$$\begin{aligned} P_o &= \sum_{t=1}^n \frac{mE_t}{(1 + k)^t} & (12) \\ &= \frac{mE_1}{(1 + k)^1} + \frac{mE_2}{(1 + k)^2} + \frac{mE_3}{(1 + k)^3} + \dots + \frac{mE_n}{(1 + k)^n} \end{aligned}$$

Observation will disclose that in fact the payout ratio is volatile and tends to offset the volatility in earnings so that dividend growth (realized cash flows) is smoothed.

Equation (12) can be restated to read:

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$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \dots + \frac{D_n}{(1+k)^n} \quad (13)$$

$$= \sum_{t=1}^n \frac{D_t}{(1+k)^t}$$

The relationship between D_{t-1} and D_t is simply $(1+g)$, which is also the relationship between E_{t-1} and E_t defined in (8). And, with an assumed constant payout ratio or share of earnings, the following is obtained:

$$P_o = \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \dots + \frac{D_o(1+g)^n}{(1+k)^n} \quad (14)$$

$$= \sum_{t=1}^n \frac{D_o(1+g)^t}{(1+k)^t}$$

Now, assume an infinite time horizon:

$$P_o = \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \dots + \frac{D_o(1+g)^\infty}{(1+k)^\infty} \quad (15)$$

Equation (15) above is simply a geometric series with a growth and discounting parameter, $(1+g)/(1+k)$, that defines the relative value of any two sequential terms.⁵⁶ Therefore, (15) may be expressed as:

$$P_o = \frac{D_o(1+g)}{(1+k)} \left[\frac{1 - [(1+g)/(1+k)]^\infty}{1 - (1+g)/(1+k)} \right] \quad (16)$$

And since $((1+g)/(1+k))^\infty$ is zero,⁵⁷ and $(1-(1+g)/(1+k))$ is equal to $(k-g)/(1+k)$, the following form can be obtained:

$$P_o = D_o(1+g)/(k-g) \quad (17)$$

⁵⁶ With $(1+g) = d$, and $(1+k) = r$, a series of the form:

$$\sum_{t=1}^n a(d/r)^t = a \sum_{t=1}^n (d/r)^t$$

This may be alternately expressed as:

$$a \frac{d}{r} [(1 - (d/r)^n) / (1 - (d/r))]$$

⁵⁷ If $k > g$

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Multiplying through by $(k-g)$ and $1/P_o$, and rearranging gives:

$$k = D_o(1+g)/P_o + g \quad (18)$$

This is the derived form of the constant growth Discounted Cash Flow model.

In addition, the assumption of an infinite time horizon can be relaxed. Assume that the investor has a finite time horizon, n , with a salvage value equal to P_n and a constant price-earnings ratio. Equation (14) is then restated as:

$$P_o = \sum_{t=1}^n \frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_n}{(1+k)^n} \quad (19)$$

Since $P_o/E_o = P_n/E_n$, $P_n = P_o(1+g)^n$. Thus, (19) can be restated as:

$$P_o = \sum_{t=1}^n \frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_o(1+g)^n}{(1+k)^n} \quad (20)$$

The first term on the right may be restated as described above, and incorporated into (21), shown below:

$$P_o = \frac{D_o(1+g)}{(k-g)} [1 - (1+g)^n / (1+k)^n] + P_o(1+g)^n / (1+k)^n \quad (21)$$

Rearranging and simplifying terms obtains:

$$P_o - P_o(1+g)^n / (1+k)^n = \frac{D_o(1+g)}{(k-g)} [1 - (1+g)^n / (1+k)^n] \quad (22)$$

or,

$$P_o [1 - (1+g)^n / (1+k)^n] = \frac{D_o(1+g)}{(k-g)} [1 - (1+g)^n / (1+k)^n]$$

Now, dividing both sides by $[1 - (1+g)^n / (1+k)^n]$ gives an equivalent result to (17):

$$P_o = D_o(1+g)/(k-g) \quad (23)$$

Rearranging terms provides:

$$k = D_o(1+g)/P_o + g \quad (24)$$

Thus, the constant growth form of Discounted Cash Flow is derived for a finite time horizon.

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Multi-Stage DCF

The model of constant growth over the future holding period may not be a fully satisfactory representation of investor expectations under some market conditions. The constant growth form can be generalized to a varying growth path or growth with stochastic elements. Such approach increases complexity.

As a practical matter, a useful extension of the constant growth model known as multi-stage DCF can be easily developed. Arguably, multi-stage DCF presents a platform for a more accurate representation of expectations of growth harbored by investors. A derived form of the multi-stage form is developed below:

Multi-stage DCF can be shown as a restatement of Equation 14 with three patterns or rates of growth applicable to specific forward timeframes or stages:

$$P_o = \sum_{t=1}^5 \frac{D_o(1+g_1)^t}{(1+k)^t} + \sum_{t=1}^5 \frac{D_5(1+g_2)^t}{(1+k)^t} (1/(1+k)^5) + \sum_{t=1}^{\infty} \frac{D_{10}(1+g_3)^t}{(1+k)^t} (1/(1+k)^{10}) \quad (25)$$

Each stage can be shown in a simplified form. We begin by separating out the first stage, S_1 – i.e., the first rhs term with growth = g_1 – as follows:

$$S_1 = \sum_{t=1}^5 \frac{D_o(1+g_1)^t}{(1+k)^t} \quad (26)$$

Pulling out the initial rate of dividends, D_o , from the sum,

$$S_1 = D_o \sum_{t=1}^5 \frac{(1+g_1)^t}{(1+k)^t}$$

Presenting the ratio of the growth and discount factors as a single term, $F = \frac{(1+g_1)}{(1+k)}$, and incorporating

F into the sum, $S_1 = D_o \sum_t F^t$.

The sum can then be expanded as follows:

$$S_1 = D_o (F^1 + F^2 + \dots + F^5). \quad (27)$$

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Defining a new term equal to unity, $\frac{(1-F)}{(1-F)}$, and including the term into the rhs of Equation 27:

$$S_1 = D_o \left(F^1 + F^2 + \dots + F^5 \right) \left(\frac{(1-F)}{(1-F)} \right), \text{ and then expanding,}$$

$$S_1 = D_o \left((F^1 + F^2 + \dots + F^5) - (F^2 + F^3 + \dots + F^6) \right) / (1-F). \quad (28)$$

Canceling terms of Equation 28 provides, $S_1 = D_o (F^1 - F^6) / (1-F)$, and then collecting common terms gives a simplified result, as follows:

$$S_1 = D_o F^1 (1 - F^5) / (1-F) \quad (29)$$

Expanding F in Equation 29 provides,

$$S_1 = D_o \left(\frac{(1+g_1)}{(1+k)} \right) \left(1 - \left(\frac{(1+g_1)}{(1+k)} \right)^5 \right) / \left(\frac{(1+k) - (1+g_1)}{(1+k)} \right)$$

Finally, canceling terms to simplify Equation 29 provides the result,

$$S_1 = D_o (1+g_1) \left(1 - \left(\frac{(1+g_1)}{(1+k)} \right)^5 \right) / (k - g_1) \quad (30)$$

The above result for Stage 1 can be stated as follows,

$$S_1 = D_o \left(\frac{(1+g_1)}{(k-g_1)} \right) \left(1 - \left(\frac{(1+g_1)}{(1+k)} \right)^5 \right) \quad (31)$$

Note that this outcome for Stage 1 is identical to Equation 22, above.

Stage 2 of Equation 25 is:

$$S_2 = \sum_{t=1}^5 \frac{D_5 (1+g_2)^t}{(1+k)^t} (1/(1+k)^5)$$

The derived form of Stages 2 and 3 are obtained through application of the same procedures as above, and need not be reviewed. The derived result for Stage 2 is as follows:

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$$S_2 = D_5 \left(\frac{(1+g_2)}{(k-g_2)} \right) \left(1 - \left(\frac{(1+g_2)}{(1+k)} \right)^5 \right) (1/(1+k)^5) \quad (32)$$

Stage 3 of Equation 25 is:

$$S_3 = \sum_{t=1}^{\infty} \frac{D_{10}(1+g_3)^t}{(1+k)^t} (1/(1+k)^{10})$$

Similarly, the derived form of Stage 3 is:

$$S_3 = D_{10} \left(\frac{(1+g_3)}{(k-g_3)} \right) \left(1 - \left(\frac{(1+g_3)}{(1+k)} \right)^{\infty} \right) (1/(1+k)^{10}) \quad (33)$$

Note that in Stage 3, the second term in the second bracket of the rhs vanishes as a result of, by assumption, $k > g$.

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Appendix II

Capital Asset Pricing Model (CAPM)⁵⁸

The Sharpe-Lintner Capital Asset Pricing Model (CAPM)—William Sharpe (1964) and John Lintner (1966)—is an extension of the one-period, mean-variance portfolio model of Markowitz (1959) and Tobin (1958), which in turn is built on the expected utility model of von Neumann and Morgenstern (1953). The Markowitz mean-variance analysis is concerned with how the investor should allocate wealth among the various assets available in the market, given that the investor is a one-period utility maximizer.

The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk free returns and an *adjusted risk-based return*. Surrogates for risk free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns associated with government debt obligations serve as appropriate surrogates.

The CAPM defines the market rate of return of asset j as a combination of the risk free return, R_f , and the product of a risk factor and the excess return above the risk free return, $\beta_{jm}(R_m - R_f)$. Excess return is determined as the difference between the return of the market as a whole, R_m , and the risk-free return. The relevant risk factor is the well-known market beta, which is defined as, the covariation of the market return of individual assets and equity markets as a whole

$$\beta_{jm} = \sigma_{jm} / \sigma_m^2 \quad (1)$$

Start with an investment amount, I , where the share, α , is invested in asset j , and the share $(1 - \alpha)$ is invested in the market portfolio, m . The rate of return on the portfolio is,

$$R_\alpha = \alpha R_j + (1 - \alpha) R_m \quad (2)$$

⁵⁸ As derived by and shown in *Investment Science*, by David Luenberger, 1998 but with explicit inclusion of intermediate steps of derivation. Intermediate steps have not been subject to peer review.

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The measure of variation of portfolio returns involves the variance of the two random variables, R_j and R_m , each having a variance equal to the square of any factor—i.e., the variance of α along with the variances of the variables R including cross products. This result is shown below:

$$\sigma^2_\alpha = (\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2) \quad (3)$$

or,

$$\sigma_\alpha = (\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2)^{1/2} \quad (3.1)$$

As the portfolio share coefficient, α , approaches zero, the return on the portfolio equals to R_m . The R_m point within the rate-of-return—risk space is equivalent to the tangency point of market portfolio with the well-known market line.

Optimization of the portfolio involves defining the optimal placement of α within return—risk space. Taking the derivative of equation (2) with respect to α ,

$$dR_\alpha/d\alpha = R_f - R_m \quad (4)$$

Similarly, the derivative of (3.1) with respect to α obtains,

$$d\sigma_\alpha/d\alpha = d(\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2)^{1/2}/d\alpha \quad (5)$$

Collapsing equation (5) to a function of α ,

$$d(\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2)^{1/2}/d\alpha = d(f(\alpha))^{1/2}/d\alpha \quad (5.1)$$

Taking the derivative of the rhs of (5.1) resulting in two terms,

$$= \frac{1}{2} * df(\alpha)^{-1/2} / d\alpha = \frac{1}{2} * f(\alpha)^{1/2} (df(\alpha)/d\alpha) \quad (5.2)$$

The 2nd term of (5.2) is the derivative shown in (3),

$$df(\alpha)/d\alpha = d(\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2)/d\alpha \quad (5.3)$$

Expanding the 2nd and 3rd terms of (5.3) and taking the derivative with respect to α ,

$$df(\alpha)/d\alpha = d(\alpha^2\sigma_j^2 + 2(\alpha - \alpha^2)\sigma_{jm} + (1 - 2\alpha + \alpha^2)\sigma_m^2)/d\alpha \quad (5.4)$$

and,

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$$= 2\alpha\sigma_j^2 + 2(1 - 2\alpha)\sigma_{jm} + (-2 + 2\alpha)\sigma_m^2 \quad (5.5)$$

Simplifying (5.5),

$$df(\alpha)/d\alpha = 2(\alpha\sigma_j^2 + (1 - 2\alpha)\sigma_{jm} + (\alpha - 1)\sigma_m^2) \quad (5.6)$$

Returning to (5.2) and incorporating (5.6) yields,

$$d\sigma_\alpha/d\alpha = \frac{1}{2} f(\alpha)^{-1/2} 2(\alpha\sigma_j^2 + (1 - 2\alpha)\sigma_{jm} + (\alpha - 1)\sigma_m^2) \quad (5.7)$$

Rearranging terms,

$$d\sigma_\alpha/d\alpha = \frac{1}{2} * 2(\alpha\sigma_j^2 + (1 - 2\alpha)\sigma_{jm} + (\alpha - 1)\sigma_m^2) / f(\alpha)^{1/2} \quad (5.8)$$

As shown above in (3.1), $f(\alpha)^{1/2}$ is equivalent to σ_α , thus, (5.8) can be restated,

$$d\sigma_\alpha/d\alpha = (\alpha\sigma_j^2 + (1 - 2\alpha)\sigma_{jm} + (\alpha - 1)\sigma_m^2) / \sigma_\alpha \quad (5.9)$$

With the share coefficient, α , set to $\alpha=0$, equation (5.9) simplifies to,

$$d\sigma_\alpha/d\alpha = (\sigma_{jm} - \sigma_m^2) / \sigma_m \quad (6)$$

Key relationships associated with the derivative of R_α with respect to σ ,

$$dR_\alpha/d\sigma_\alpha = (dR_\alpha/d\alpha)(d\alpha/d\sigma_\alpha); \text{ and } (d\alpha/d\sigma_\alpha) = 1/(d\sigma_\alpha/d\alpha) \quad (7.1)$$

Thus,

$$dR_\alpha/d\sigma_\alpha = (dR_\alpha/d\alpha) / (d\sigma_\alpha/d\alpha) \quad (7.2)$$

For $\alpha=0$, substituting in the two derivatives into the rhs of 7.2 yields,

$$dR_\alpha/d\sigma_\alpha = (R_f - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2) \quad (8)$$

Equation (8) defines the rate of change of the portfolio return with respect to risk associated with the portfolio share coefficient. (or the investment in asset R_j changes?) with respect to σ_α , the slope of the capital market line. Therefore, [this term appears without a R_f connection, although the text above captures this]

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$$(R_f - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2) = (R_m - R_f) / \sigma_m. \quad (9)$$

$$(R_f - R_m) / = (R_m - R_f) (\sigma_{jm} - \sigma_m^2) / \sigma_m. \quad (9.1)$$

$$(R_j) = R_m + (R_m - R_f) (\sigma_{jm} - \sigma_m^2) / \sigma_m^2. \quad (9.2)$$

$$R_j = R_m + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) - \sigma_m^2 / \sigma_m^2. \quad (9.3)$$

$$R_j = R_m + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) - 1. \quad (9.4)$$

$$R_j = R_m + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) - (R_m - R_f). \quad (9.5)$$

$$R_j = + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) - (-R_f). \quad (9.6)$$

$$R_j = + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) + R_f. \quad (9.7)$$

$$R_j = R_f + (R_m - R_f) (\sigma_{jm} / \sigma_m^2). \quad (9.8)$$

This is almost the first expression on the right of (10) except I have an R_f rather than an R_j in the parenthesis; I deduce that the j is a mistake and should be an f instead. The next part of the equation uses (1) above ($\beta_{jm} = \sigma_{jm} / \sigma_m^2$) so that we have the second expression on the right as a slight adjustment to 9.10 [however, (9) is still drawn as a conclusion from the statement “The result in (8) defines a rate of change with respect to σ_α , which must be equivalent to the slope of the capital market line”]

$$R_j = R_f + (R_m - R_f) (\sigma_{jm} / \sigma_m^2) (\beta_{jm} / (\sigma_{jm} / \sigma_m^2)) \quad (9.9)$$

$$R_j = R_f + (R_m - R_f) (\beta_{jm}) \quad (9.10)$$

$$R_j = R_f + \beta_{jm}(R_m - R_f) \quad (9.10')$$

Now solving for R_j obtains the capital asset pricing model, stated in its well-known form,

$$R_j = R_f + [(R_m - R_f) / \sigma_m^2] \sigma_{jm} = R_f + \beta_{jm}(R_m - R_f) \quad (10)$$

where β_{jm} is defined as above.

In summary, the CAPM can be shown in the context of the general and well known formulation (as model (referred to in footnote 27 of the report text), where the expected rate of return is a function of risk:

$$R_j = f[E(F)] = R_f + \beta(R_m - R_f).$$

Exhibit 6

Exhibits

Exhibit 6

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: GAS DISTRIBUTION UTILITIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2013-2017	2017	2013-2017	2017
Atmos Energy Corp	ATO	0.76	0.70	0.64	0.55
Chesapeake Utilities	CPK	0.65	0.70	0.48	0.55
New Jersey Resources Corp	NJR	0.76	0.80	0.64	0.70
Northwest Natural Gas Co	NWN	0.66	0.65	0.49	0.48
Southwest Gas	SWX	0.80	0.75	0.70	0.63
WGL Holdings Inc	WGL	0.74	0.75	0.61	0.63
Average		0.73	0.73	0.59	0.59
Standard Deviation		0.06	0.05	0.09	0.08
Weighted Average:		0.75	0.73	0.63	0.59
CAPM ESTIMATES					
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk-Free Rate
Low	8.08%	3.20%	0.71	10.04%	3.20%
High	9.02%	3.45%	0.74	10.94%	3.45%
Weighted Average	8.69%	3.32%	0.75	10.49%	3.32%
U.S. Equity Market Risk Premia:				7.17%	
	Cost Rate, Adjusted for Issuance Costs				
Low	8.24%				
High	9.20%				
Weighted Average	8.86%				

Exhibit 6

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: MODERATE-SIZED ELECTRIC UTILITIES					
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2013-2017	2017	2013-2017	2017
Allete Inc	ALE	0.76	0.80	0.64	0.70
Black Hills Corp	BKH	0.88	0.85	0.82	0.78
El Paso Electric Co	EE	0.72	0.75	0.58	0.63
Great Plains Energy Inc	GXP	0.81	0.75	0.72	0.63
Hawaiian Electric Industries Inc	HE	0.76	0.70	0.64	0.55
IDACORP Inc	IDA	0.77	0.75	0.66	0.63
MGE Energy Inc	MGEE	0.70	0.75	0.55	0.63
OGE Energy Corp	OGE	0.88	0.95	0.82	0.93
Otter Tail Corp	OTTR	0.88	0.90	0.82	0.85
Pinnacle West Capital Corp	PNM	0.72	0.70	0.58	0.55
PNM Resources Inc	PNW	0.85	0.70	0.78	0.55
Unitil Corp	UTL	0.59	0.65	0.39	0.48
Vectren Corp	VVC	0.74	0.70	0.61	0.55
Westar Energy Inc	WR	0.74	0.70	0.61	0.55
Average		0.77	0.76	0.66	0.64
Standard Deviation		0.08	0.09	0.12	0.13
Weighted Average:		0.79	0.76	0.68	0.64
CAPM ESTIMATES					
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk-Free Rate
Low	8.33%	3.20%	0.75	10.04%	3.20%
High	9.39%	3.45%	0.79	10.94%	3.45%
Weighted Average	8.97%	3.32%	0.79	10.49%	3.32%
U.S. Equity Market Risk Premia:				7.17%	
	Cost Rate, Adjusted for Issuance Costs				
Low	8.50%				
High	9.57%				
Weighted Average	9.15%				

Exhibit 6

CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: SMALL LOW RISK NON-UTILITY COMPANIES						
Small Low-Risk Entities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred		
Company	Ticker	2013-2017	2017	2013-2017	2017	
Cambium Learning Group Inc	ABCD	0.91	0.75	0.87	0.63	
Analogic Corp	ALOG	0.89	0.80	0.84	0.70	
Asure Software Inc	ASUR	0.64	0.60	0.46	0.40	
AXT Inc	AXTI	1.05	0.70	1.07	0.55	
Continental Materials Corp	CUO	0.47	0.60	0.21	0.40	
CPI Aerostructures Inc	CVU	0.76	0.60	0.64	0.40	
Daily Journal Corp	DJCO	0.63	0.85	0.45	0.78	
EXACT Sciences Corp	EXAS	1.09	0.85	1.13	0.78	
EXFO Inc	EXFO	1.02	0.85	1.03	0.78	
National Beverage	FIZZ	0.80	0.85	0.70	0.78	
Full House Resorts Inc	FLL	0.86	0.60	0.79	0.40	
Gaia Inc.	GAIA	1.02	0.65	1.03	0.48	
Heska Corporation	HSKA	0.63	0.65	0.44	0.48	
ORBCOMM Inc	ORBC	1.02	0.80	1.03	0.70	
XO Group Inc	XOXO	0.87	0.80	0.81	0.70	
Average		0.84	0.73	0.77	0.60	
Standard Deviation		0.19	0.10	0.28	0.16	
Weighted Average:		0.88	0.81	0.83	0.71	
CAPM ESTIMATES OF THE COST OF EQUITY CAPITAL: SMALL LOW RISK NON-UTILITY COMPANIES						
	Cost of Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate	Cost Rate, Adjusted for Issuance Costs
Low	8.65%	3.20%	0.80	10.04%	3.20%	8.82%
High	10.12%	3.45%	0.89	10.94%	3.45%	10.32%
Weighted Average	9.65%	3.32%	0.88	10.49%	3.32%	9.84%
	Cost Rate, Adjusted for Issuance Costs			U.S. Equity Market Risk Premia:		7.17%
Low	8.82%					
High	10.32%					
Weighted Average	9.84%					

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2015							
Electric Utility	Ticker	Effective Year Forward		Average Market Price Per Share, April - May '15	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
		Dividend Per Share	Dividend Rate				
Atmos Energy Corp	ATO	1.48	1.50	54.36	2.75%	5.81%	8.57%
Chesapeake Utilities	CPK	1.03	1.07	50.44	2.12%	10.52%	12.64%
New Jersey Resources Corp	NJR	0.84	0.87	30.76	2.82%	10.64%	13.47%
Northwest Natural Gas Co	NWN	1.84	1.87	46.53	4.01%	7.22%	11.23%
Southwest Gas	SWX	1.46	1.46	55.63	2.62%	6.80%	9.43%
WGL Holdings Inc	WGL	1.76	1.76	56.23	3.13%	3.42%	6.55%
DCF ESTIMATES, MID-SIZED ELECTRIC UTILITIES							
				Adjusted Dividend Yield		Expected Growth	Unadjusted Cost Rate
Average				2.91%	7.40%		10.31%
S. D.				0.63%	2.79%		2.61%
Range							
Low				2.59%	6.01%		9.01%
High				3.23%	8.80%		11.62%
Weighted Average				2.77%	7.70%		10.47%
Cost Rate, Adjusted for Issuance Costs							
Weighted Average							10.65%

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2016							
Electric Utility	Ticker	Effective Year Forward		Average Market Price Per Share, April - May '16	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
		Dividend Per Share	Dividend Rate				
Atmos Energy Corp	ATO	1.56	1.58	73.09	2.17%	6.93%	9.10%
Chesapeake Utilities	CPK	1.08	1.12	60.01	1.87%	8.62%	10.49%
New Jersey Resources Corp	NJR	0.92	0.95	35.71	2.66%	7.63%	10.28%
Northwest Natural Gas Co	NWN	1.86	1.88	53.59	3.51%	5.14%	8.65%
Southwest Gas	SWX	1.62	1.62	66.39	2.44%	6.14%	8.58%
WGL Holdings Inc	WGL	1.84	1.84	67.66	2.72%	4.63%	7.35%
DCF ESTIMATES, GAS DISTRIBUTION UTILITIES							
					Adjusted	Expected	Unadjusted
Average					2.56%	6.52%	9.08%
S. D.					0.56%	1.51%	1.17%
Range							
Low					2.28%	5.76%	8.49%
High					2.84%	7.27%	9.66%
Weighted Average					2.52%	6.58%	9.09%
Cost Rate, Adjusted							
Weighted Average							9.25%

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: GAS DISTRIBUTION UTILITIES, 2017							
Electric Utility	Ticker	Effective		Average Market Price Per Share, April - May '17	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
		Dividend Per Share	Dividend Rate				
Atmos Energy Corp	ATO	1.68	1.72	80.90	2.12%	6.41%	8.53%
Chesapeake Utilities	CPK	1.15	1.20	71.88	1.67%	9.39%	11.06%
New Jersey Resources Corp	NJR	0.96	0.99	40.45	2.45%	5.69%	8.14%
Northwest Natural Gas Co	NWN	1.87	1.88	59.79	3.15%	6.23%	9.37%
Southwest Gas	SWX	1.80	1.80	82.10	2.19%	5.90%	8.09%
WGL Holdings Inc	WGL	1.85	1.85	82.56	2.24%	4.00%	6.25%
DCF ESTIMATES, GAS DISTRIBUTION UTILITIES							
					Adjusted	Expected	Unadjusted
Average					2.30%	6.27%	8.57%
S. D.					0.49%	1.75%	1.59%
Range							
Low					2.06%	5.39%	7.78%
High					2.55%	7.15%	9.37%
Weighted Average					2.27%	5.93%	8.20%
Cost Rate, Adjusted							
Weighted Average							8.35%

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2015							
Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, April - May	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of
Allete Inc	ALE	1.88	1.89	50.37	3.75%	1.96%	5.71%
Black Hills Corp	BKH	1.52	1.53	49.47	3.09%	4.76%	7.85%
El Paso Electric Co	EE	1.12	1.12	37.20	3.01%	7.89%	10.90%
Great Plains Energy Inc	GXP	0.92	0.93	26.40	3.53%	1.24%	4.76%
Hawaiian Electric Industries Inc	HE	1.24	1.24	31.41	3.95%	3.78%	7.73%
IDACORP Inc	IDA	1.72	1.79	60.92	2.94%	7.25%	10.19%
MGE Energy Inc	MGEE	1.09	1.11	41.58	2.67%	6.16%	8.82%
OGE Energy Corp	OGE	0.90	0.93	32.02	2.89%	6.49%	9.38%
Otter Tail Corp	OTTR	1.21	1.21	29.60	4.10%	2.22%	6.32%
Pinnacle West Capital Corp	PNM	2.27	2.30	61.71	3.73%	1.91%	5.64%
PNM Resources Inc	PNW	0.74	0.77	27.57	2.81%	22.35%	25.16%
Vectren Corp	VVC	1.44	1.45	43.23	3.36%	2.52%	5.88%
Westar Energy Inc	WR	1.40	1.41	37.44	3.77%	4.09%	7.86%

DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES			
	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	3.35%	5.58%	8.94%
S. D.	0.48%	5.50%	5.23%
Range			
Low	3.11%	2.84%	6.33%
High	3.59%	8.33%	11.55%
Weighted Average	3.33%	6.31%	9.65%
			Cost Rate, Adjusted for
	Weighted Average		9.86%

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2016							
Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, April - May	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of
Allete Inc	ALE	2.02	2.03	55.96	3.64%	4.19%	7.83%
Black Hills Corp	BKH	1.62	1.63	59.32	2.75%	7.28%	10.02%
El Paso Electric Co	EE	1.18	1.18	44.80	2.63%	6.45%	9.09%
Great Plains Energy Inc	GXP	0.98	1.00	31.31	3.19%	2.74%	5.93%
Hawaiian Electric Industries Inc	HE	1.24	1.24	32.61	3.80%	5.48%	9.28%
IDACORP Inc	IDA	4.00	4.21	72.80	5.78%	7.36%	13.14%
MGE Energy Inc	MGEE	1.13	1.16	50.45	2.29%	5.52%	7.81%
OGE Energy Corp	OGE	1.00	1.04	29.31	3.54%	5.72%	9.26%
Otter Tail Corp	OTTR	1.23	1.23	29.22	4.22%	3.09%	7.31%
Pinnacle West Capital Corp	PNM	2.38	2.42	73.21	3.30%	4.42%	7.73%
PNM Resources Inc	PNW	0.80	0.84	32.29	2.61%	8.82%	11.43%
Vectren Corp	VVC	1.52	1.54	49.38	3.11%	6.09%	9.21%
Westar Energy Inc	WR	1.44	1.45	51.33	2.83%	5.07%	7.89%
DCF ESTIMATES, MODERATE-SIZED ELECTRIC UTILITIES							
					Adjusted	Expected	Unadjusted
Average					3.36%	5.56%	8.92%
S. D.					0.91%	1.72%	1.87%
Range							
Low					2.91%	4.70%	7.98%
High					3.82%	6.41%	9.85%
Weighted Average					3.33%	5.72%	9.05%
Cost Rate,							
Weighted Average							9.27%

Exhibit 6

DISCOUNTED CASH FLOW ESTIMATES OF COST OF EQUITY: MODERATE-SIZED ELECTRIC UTILITIES, 2017							
Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend	Average Market Price Per Share, April - May	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of
Allete Inc	ALE	2.14	2.16	69.75	3.09%	2.96%	6.05%
Black Hills Corp	BKH	1.78	1.79	68.05	2.63%	5.94%	8.57%
El Paso Electric Co	EE	1.34	1.34	51.66	2.59%	6.10%	8.69%
Great Plains Energy Inc	GXP	1.10	1.13	28.96	3.89%	1.72%	5.61%
Hawaiian Electric Industries Inc	HE	1.24	1.24	33.27	3.73%	3.21%	6.94%
IDACORP Inc	IDA	2.20	2.33	84.40	2.76%	6.65%	9.41%
MGE Energy Inc	MGEE	1.23	1.26	64.54	1.96%	4.57%	6.52%
OGE Energy Corp	OGE	1.21	1.26	34.68	3.65%	5.53%	9.17%
Otter Tail Corp	OTTR	1.28	1.28	38.50	3.33%	4.69%	8.03%
Pinnacle West Capital Corp	PNM	2.62	2.67	85.21	3.13%	3.48%	6.61%
PNM Resources Inc	PNW	0.97	1.03	37.40	2.75%	20.11%	22.86%
Vectren Corp	VVC	1.68	1.71	59.49	2.87%	3.14%	6.00%
Westar Energy Inc	WR	1.60	1.61	52.83	3.05%	3.82%	6.88%

DCF ESTIMATES, MID-SIZED ELECTRIC UTILITIES			
	Adjusted	Expected	Unadjusted
Average	3.03%	5.53%	8.57%
S. D.	0.53%	4.61%	4.48%
Range			
Low	2.77%	3.23%	6.33%
High	3.30%	7.84%	10.81%
Weighted Average	3.10%	6.08%	9.18%
			Cost Rate,
	Weighted Average		9.38%

Exhibit 6

HISTORICAL MARKET RETURNS FOR GAS DISTRIBUTION UTILITIES, AVERAGE PER ANNUM								
Company	2007-09	2008-10	2009-11	2010-12	2011-13	2012-14	2013-15	2014-16
Atmos Energy Corp	-1.2%	4.9%	12.4%	6.1%	13.8%	0.0%	21.7%	17.8%
Chesapeake Utilities	12.1%	0.5%	15.4%	-13.1%	8.0%	0.0%	-12.5%	-14.9%
New Jersey Resources Corp	5.3%	9.4%	8.1%	3.3%	3.8%	10.0%	18.9%	15.9%
Northwest Natural Gas Co	2.5%	-1.4%	2.7%	-0.5%	-2.6%	19.1%	4.9%	12.0%
Southwest Gas	-8.2%	8.8%	19.2%	14.7%	15.8%	14.4%	10.5%	12.9%
WGL Holdings Inc	1.0%	3.0%	11.0%	6.3%	4.8%	13.6%	18.0%	24.3%
Average	1.9%	4.2%	11.5%	2.8%	7.3%	9.5%	10.3%	11.3%
Weighted Average	0.1%	5.1%	11.8%	5.5%	9.2%	7.8%	15.5%	15.6%
								10.1%

Note: Market Returns for the 2007-09 experience are excluded from the average

Exhibit 6

HISTORICAL MARKET RETURNS FOR MODERATE-SIZED ELECTRIC UTILITIES, AVERAGE PER ANNUM								
Company	2007-09	2008-10	2009-11	2010-12	2011-13	2012-14	2013-15	2014-16
Allete Inc	-10.7%	-1.1%	9.3%	8.1%	10.7%	10.0%	8.1%	9.7%
Black Hills Corp	-6.9%	-9.1%	7.8%	10.9%	21.5%	17.9%	11.0%	6.9%
CMS Energy Corp	5.7%	10.6%	30.8%	16.0%	13.0%	16.7%	14.5%	16.3%
El Paso Electric Co	-4.1%	6.2%	24.6%	17.9%	9.3%	5.4%	6.7%	10.3%
Eversource Energy	-1.6%	2.5%	14.6%	15.0%	10.0%	14.4%	10.0%	9.9%
Great Plains Energy Inc	-13.9%	-11.3%	4.2%	1.9%	8.3%	9.9%	10.9%	4.5%
Hawaiian Electric Industries Inc	-8.2%	0.2%	6.5%	6.7%	4.9%	9.0%	6.2%	9.7%
IDACORP Inc	-5.6%	2.6%	13.0%	10.9%	12.2%	16.5%	16.7%	16.3%
MGE Energy Inc	-0.6%	7.0%	12.4%	12.7%	10.5%	13.6%	11.2%	20.3%
OGE Energy Corp	1.6%	12.5%	30.4%	15.8%	14.7%	8.1%	-0.3%	2.0%
Otter Tail Corp	-5.0%	-11.8%	-1.7%	0.7%	9.4%	12.1%	3.0%	15.0%
Pinnacle West Capital Corp	-8.9%	1.0%	14.5%	11.8%	8.6%	12.9%	9.1%	14.8%
PNM Resources Inc	-19.5%	-8.2%	22.8%	18.5%	23.4%	17.7%	14.5%	12.7%
SCANA Corporation	-2.0%	-0.6%	8.2%	6.7%	5.0%	10.9%	10.6%	16.7%
Unitil Corp	-1.3%	-5.8%	11.7%	5.0%	11.3%	9.9%	11.9%	14.8%
Vectren Corp	-4.2%	-4.1%	6.9%	6.4%	12.4%	16.1%	14.2%	15.0%
Average	-5.4%	-0.3%	13.9%	10.6%	11.5%	12.3%	9.6%	12.0%
Weighted Average	-4.1%	1.1%	15.7%	11.7%	11.4%	13.3%	10.4%	11.8%
								10.8%

Note: Market Returns for the 2007-09 experience are excluded from the average

Exhibit 6

HISTORICAL MARKET RETURNS FOR SMALL LOW RISK NON-UTILITY COMPANIES, 2007-2016								
Company	2007-09	2008-10	2009-11	2010-12	2011-13	2012-14	2013-15	2014-16
Cambium Learning Group				-29.2%	-8.6%	-4.6%	80.6%	65.0%
Analogic Corp	0.7%	3.3%	28.5%	24.7%	21.5%	14.8%	4.1%	-2.1%
Asure Software Inc	-12.9%	4.7%	70.6%	52.2%	50.4%	11.4%	-8.0%	23.1%
AXT Inc	31.3%	94.6%	100.6%	42.9%	-33.3%	-10.8%	-3.8%	29.8%
Continental Material Corp	-23.6%	10.7%	7.9%	26.5%	5.6%	12.5%	3.2%	10.6%
CPI Aerostructures Inc.	-2.4%	35.6%	42.6%	34.3%	6.3%	0.8%	4.5%	-13.9%
Daily Journal Corp	20.4%	26.7%	29.2%	16.2%	46.6%	62.1%	40.4%	11.2%
Exact Sciences Corp	142.1%	162.9%	202.3%	47.5%	25.7%	58.3%	26.0%	37.3%
EXFO Inc	-7.7%	24.1%	31.6%	19.2%	-12.2%	-15.8%	-19.7%	4.2%
National Beverage	11.6%	20.2%	23.7%	2.6%	17.1%	13.7%	50.4%	41.8%
Full House Resorts	40.3%	48.6%	61.1%	2.4%	-3.4%	-12.6%	-16.5%	4.3%
Gaia Inc	33.0%	-6.0%	2.9%	-20.1%	16.4%	38.2%	34.9%	11.3%
Heska Corporation	11.5%	6.4%	50.9%	17.2%	21.9%	42.2%	76.3%	102.1%
ORBCOMM Inc	-23.1%	-14.9%	12.1%	14.2%	36.1%	32.0%	25.2%	9.4%
XO Group	-22.0%	-9.6%	1.2%	-2.0%	18.6%	31.3%	23.5%	10.6%
Average*	4.4%	18.8%	35.6%	14.4%	13.1% #	15.4% #	21.1% #	22.0%
Weighted Average*	1.2%	9.1%	29.7%	14.6%	20.9% #	21.3% #	32.9% #	30.9%
* Does not include realized market returns of Exact Sciences Corp								13.4%

Exhibit 6

HISORICAL MARKET RETURNS OF COMPARABLE RISK NO-UTILITY COMPANIES, 1999-2007					
Company	1999 - 2003	1999 - 2004	1999 - 2005	1999 - 2006	1999 - 2007
Merchants Bancshares Inc.	12.92%	15.57%	12.98%	10.76%	9.65%
Great Southern Bancorp	17.52%	22.86%	20.82%	17.29%	14.90%
Steinway Musical	-7.82%	6.33%	4.42%	4.40%	5.17%
U S Lime & Minerals	-8.72%	11.49%	27.11%	29.67%	27.52%
NewBridge Bancorp	2.69%	2.25%	3.15%	3.11%	0.70%
Winmark Corp	11.69%	19.98%	15.41%	14.68%	11.25%
CPI Corp.	-3.03%	-3.59%	-0.59%	11.87%	15.39%
Indep Bank Corp/MI	22.64%	20.36%	19.30%	16.45%	10.69%
Patriot Transportation Holdin	-1.86%	2.62%	9.88%	14.38%	15.19%
Vitran Corporation Inc	17.08%	26.05%	22.13%	20.87%	17.35%
Supreme Inds Inc.	-6.81%	-0.30%	2.47%	1.91%	1.68%
Farmers Capital Bank Corp.	1.11%	2.49%	2.11%	2.02%	1.28%
Alamo Group	0.94%	7.12%	9.42%	8.78%	8.50%
Northwest Pipe Co	-5.94%	-0.98%	6.70%	7.62%	9.50%
Oil-Dri Corp of Amer	-5.33%	6.67%	7.86%	8.37%	9.05%
Samuel Manu-Tech Inc.	-7.40%	-0.86%	3.66%	5.80%	5.12%
Meadowbrook Ins Grou	-28.63%	-14.72%	-11.35%	-2.50%	-0.58%
Frisch's Restaurants	11.04%	15.86%	13.53%	11.31%	12.15%
Sunlink Health Sys	0.00%	0.00%	0.00%	0.00%	0.00%
NAPCO Security Systems Inc.	14.51%	15.99%	28.59%	35.87%	30.40%
Old Second Bancorp	19.94%	21.69%	20.81%	18.39%	15.83%
Village Super Market 'A'	20.81%	21.59%	23.33%	26.45%	28.00%
Utah Medical Prods.	26.80%	24.16%	21.49%	23.38%	21.12%
SL Inds. Inc.	-10.26%	0.79%	6.36%	6.67%	6.94%
Average	3.91%	9.31%	11.23%	12.40%	11.53%
Weighted Average	3.44%	8.89%	10.92%	12.36%	11.58%
Across Years:				Average:	9.68%
				Weighted:	9.44%

Exhibit 6

SELECTION SCREEN 1: GAS DISTRIBUTION UTILITIES										
Company	Ticker	2016 Market Cap (\$M)	2016 Share Price (\$)	CAPITAL ASSET PRICING MODEL, BETA			FINANCIAL METRICS, 2015			
				CAPM Beta, Early '17	Average, 2013-Early '17	Standard Deviation, 2013-Early '17	Operating Revenues (M\$)	Return to Capital (M\$)	Total Net Plant (M\$)	Net Plant/Reven
Atmos Energy Corp	ATO	6,961	68.60	0.70	0.76	0.07	4,142	373	7,431	1.79
Chesapeake Utilities	CPK	944	61.85	0.70	0.65	0.05	459	45	855	1.86
Delta Natural Gas Company Inc	DGAS	177	25.16	0.70	0.58	0.08				
New Jersey Resources Corp	NJR	2,916	34.23	0.80	0.76	0.07	2,734	168	2,128	0.78
Northwest Natural Gas Co	NWN	1,514	55.21	0.65	0.66	0.04	724	75	2,183	3.02
Southwest Gas	SWX	3,122	65.89	0.75	0.80	0.05	2,464	173	3,891	1.58
WGL Holdings Inc	WGL	3,467	69.64	0.75	0.74	0.05	2,660	184	3,673	1.38
Average		\$2,729		0.72	0.71	0.06	\$2,197	\$170	\$3,360	1.74
Standard Deviation		\$2,229		0.05	0.08		\$1,382	\$115	\$2,286	0.74

Exhibit 6

SELECTION SCREEN 1: MODERATE-SIZED ELECTRIC UTILITIES										
Company	Ticker	2016 Market Cap (\$M)	2016 Share Price (\$)	CAPITAL ASSET PRICING MODEL, BETA			FINANCIAL METRICS, 2015			
				CAPM Beta, Early '17	Average, 2013-Early '17	Standard Deviation, 2013-Early '17	Operating Revenues (M\$)	Return to Capital (M\$)	Total Net Plant (M\$)	Net Plant/Reven
Allete Inc	ALE	2,824	57.51	0.80	0.76	0.04	1,486.40	196.56	3,669.10	2.47
Black Hills Corp	BKH	2,758	53.89	0.85	0.88	0.06	1,304.60	163.30	3,259.10	2.50
CMS Energy Corp	CMS	10,768	38.85	0.65	0.72	0.04	6,456.00	714.44	14,705.00	2.28
El Paso Electric Co	EE	1,719	42.50	0.75	0.72	0.03	849.90	113.99	2,695.50	3.17
Eversource Energy	ES	16,859	53.15	0.65	0.72	0.04	7,954.80	1,062.22	19,892.00	2.50
Great Plains Energy Inc	GXP	4,220	27.33	0.75	0.81	0.04	2,502.20	312.51	8,662.40	3.46
Hawaiian Electric Industries Inc	HE	3,332	31.01	0.70	0.76	0.07	2,603.00	197.99	4,377.70	1.68
IDACORP Inc	IDA	3,739	74.28	0.75	0.77	0.04	1,270.30	234.56	3,992.40	3.14
MGE Energy Inc	MGEE	1,936	55.85	0.75	0.70	0.06	564.00	81.11	1,243.40	2.20
OGE Energy Corp	OGE	5,965	29.87	0.95	0.88	0.08	2,196.90	412.04	7,322.40	3.33
Otter Tail Corp	OTTR	1,276	33.72	0.90	0.88	0.04	779.80	70.42	1,387.80	1.78
Pinnacle West Capital Corp	PNM	3,600	32.44	0.70	0.72	0.03	3,495.40	514.96	11,809.00	3.38
PNM Resources Inc	PNW	5,676	71.26	0.70	0.85	0.11	1,439.10	188.93	4,535.40	3.15
SCANA Corporation	SCG	9,558	66.89	0.65	0.69	0.04	4,380.00	702.15	13,425.00	3.07
Vectren Corp	VVC	3,915	47.29	0.70	0.74	0.04	2,434.70	238.46	4,089.50	1.68
Westar Energy Inc	WR	6,980	49.38	0.70	0.74	0.02	2,459.20	368.82	8,793.10	3.58
Average		\$5,320		0.75	0.77	0.05	\$2,636	\$348	\$7,116	2.71
Standard Deviation		\$4,084		0.09	0.07		\$2,070	\$275	\$5,382	0.66

Exhibit 6

SELECTION SCREEN 1: SMALL LOW-RISK NON-UTILITY COMPANIES								
Company	Ticker	2016 Market Cap (\$M)	2016 Share Price (\$)	CAPITAL ASSET PRICING MODEL, BETA			FINANCIAL METRICS, 2015	
				CAPM Beta, Early '17	Average, 2013- Early '17	Standard Deviation, 2013-Early '17	Operating Revenues (M\$)	Operating Margin (%)
Cambium Learning Group Inc	ABCD	224	4.92	0.75	0.91	0.13	152.40	0.27
Analogic Corp	ALOG	1,028	82.77	0.80	0.89	0.07	508.80	0.12
Asure Software Inc	ASUR	39	6.51	0.60	0.64	0.10	35.50	0.10
AXT Inc	AXTI	120	3.64	0.70	1.05	0.24	81.30	0.01
Continental Materials Corp	CUO	32	19.45	0.60	0.47	0.09	151.60	0.03
CPI Aerostructures Inc	CVU	81	9.49	0.60	0.76	0.10	81.30	0.10
Daily Journal Corp	DJCO	306	221.90	0.85	0.63	0.15	41.60	0.05
Deswell Industries Inc	DSWL	26	1.61					
EXACT Sciences Corp	EXAS	1,001	11.30	0.85	1.09	0.15	99.40	
EXFO Inc	EXFO	215	3.57	0.85	1.02	0.10	232.60	0.05
National Beverage	FIZZ	2,239	48.26	0.85	0.80	0.05	800.00	0.15
Full House Resorts Inc	FLL	38	2.04	0.60	0.86	0.16	146.00	0.10
Gaia Inc.	GAIA	182	7.45	0.65	1.02	0.29	17.20	0.05
Heska Corporation	HSKA	350	55.14	0.65	0.63	0.04		0.12
ORBCOMM Inc	ORBC	543	7.76	0.80	1.02	0.17	186.70	0.21
Perfumania Holdings Inc	PERF			0.85	0.75	0.15		0.02
XO Group Inc	XOXO	473	17.76	0.80	0.87	0.07		0.16
Average		\$431		0.74	0.84	0.13	\$195.0	10.3%
Standard Deviation		\$577		0.11	0.18		\$221.3	7.4%

Exhibit 6

SELECTION SCREEN 2: GAS DISTRIBUTION UTILITIES														
Company	Ticker	EQUITY PARTICIPATION IN TOTAL CAPITAL (%)					MEASURES OF MARKET RISKS				MEASURES OF BUSINESS AND FINANCIAL RISKS			
											Recent 5 Years		Recent 10 Years	
		Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share									
		2011	2013	2015	2016	Average	CAPM Beta, Early '17	Average, 2013-Early '17	CAPM Standard Deviation, 2013-Early 2017	Variation In Annual Market Returns (%)				
Atmos Energy Corp	ATO	0.51	0.51	0.57	0.61	0.55	0.70	0.76	0.07	14.1%	0.11	1.23	0.09	1.28
Chesapeake Utilities	CPK	0.69	0.70	0.71	0.77	0.71	0.70	0.65	0.05	47.7%	0.03	0.41	0.07	0.72
New Jersey Resources Corp	NJR	0.65	0.63	0.57	0.52	0.60	0.80	0.76	0.07	13.4%	0.26	3.88	0.30	3.42
Northwest Natural Gas Co	NWN	0.53	0.52	0.58	0.56	0.54	0.65	0.66	0.04	9.2%	0.07	-3.19	0.53	5.37
Southwest Gas	SWX	0.57	0.51	0.51	0.52	0.51	0.75	0.80	0.05	19.8%	0.09	1.53	0.18	2.84
WGL Holdings Inc	WGL	0.66	0.70	0.56	0.48	0.62	0.75	0.74	0.05	13.4%	0.14	1.64	0.12	1.97
Average		60%	60%	58%	58%	59%	0.73	0.73	0.05	20%	0.12	0.91	0.21	2.60
Standard Deviation		8%	9%	7%	10%		0.05	0.06		14%	0.08	2.32	0.18	1.68

Exhibit 6

SELECTION SCREEN 2: MODERATE-SIZED ELECTRIC UTILITIES														
Company	Ticker	EQUITY PARTICIPATION IN TOTAL CAPITAL (%)					MEASURES OF MARKET RISKS				MEASURES OF BUSINESS AND FINANCIAL RISKS			
											Recent 5 Years		Recent 10 Years	
		Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share									
		2011	2013	2015	2016	Average	CAPM Beta, Early '17	Average, 2013-Early '17	CAPM Standard Deviation, 2013-Early 2017	Variation In Annual Market Returns (%)				
Allete Inc	ALE	0.56	0.55	0.54	0.58	0.56	0.80	0.76	0.04	11.0%	0.10	2.52	0.16	6.30
Black Hills Corp	BKH	0.49	0.48	0.44	0.34	0.47	0.85	0.88	0.06	22.0%	0.42	1.61	0.52	-44.69
El Paso Electric Co	EE	0.48	0.49	0.47	0.47	0.47	0.75	0.72	0.03	17.6%	0.11	-48.29	0.18	2.26
Great Plains Energy Inc	GXP	0.52	0.49	0.49	0.56	0.52	0.75	0.81	0.04	14.5%	0.14	2.33	0.24	9.39
Hawaiian Electric Industries	HE	0.54	0.55	0.56	0.58	0.55	0.70	0.76	0.07	13.4%	0.25	2.11	0.22	2.97
IDACORP Inc	IDA	0.54	0.53	0.54	0.55	0.54	0.75	0.77	0.04	12.9%	0.03	1.05	0.12	1.98
MGE Energy Inc	MGEE	0.60	0.61	0.64	0.65	0.62	0.75	0.70	0.06	12.8%	0.10	2.08	0.09	1.68
OGE Energy Corp	OGE	0.48	0.57	0.56	0.59	0.54	0.95	0.88	0.08	22.7%	0.09	-58.88	0.09	2.45
Otter Tail Corp	OTTR	0.54	0.58	0.58	0.57	0.56	0.90	0.88	0.04	21.5%	0.56	1.54	0.51	6.09
Pinnacle West Capital Corp	PNM	0.56	0.60	0.57	0.54	0.57	0.70	0.72	0.03	15.9%	0.08	1.28	0.17	4.81
PNM Resources Inc	PNW	0.48	0.50	0.46	0.44	0.48	0.70	0.85	0.11	26.3%	0.08	0.92	1.42	3.49
Vectren Corp	VVC	0.48	0.47	0.49	0.53	0.50	0.70	0.74	0.04	14.1%	0.14	1.60	0.13	2.87
Westar Energy Inc	WR	0.50	0.50	0.53	0.52	0.51	0.70	0.74	0.02	14.6%	0.12	1.78	0.19	4.54
Average		52%	53%	53%	53%	53%	0.77	0.79	0.05	17%	0.17	-6.80	#	0.31
Standard Deviation		4%	5%	6%	8%	4%	0.08	0.07		5%	0.15	20.88	#	0.36

Exhibit 6

SELECTION SCREEN 2: SMALL LOW-RISK NON-UTILITY COMPANIES														
Company	Ticker	EQUITY PARTICIPATION IN TOTAL CAPITAL (%)					MEASURES OF MARKET RISKS				MEASURES OF BUSINESS AND FINANCIAL RISKS			
											Recent 5 Years		Recent 10 Years	
		Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share									
		2011	2013	2015	2016	Average	CAPM Beta, Early '17	Average, 2013-Early '17	Standard Deviation, 2013-Early '17	Variation In Annual Market Returns (%)				
Cambium Learning Group Inc	ABCD	0.43	0.33	-0.35	-0.56	-0.04	1.00	0.91	0.13	0.71	3.83	-2.27	3.48	-2.39
Analogic Corp	ALOG						0.95	0.89	0.07	0.27	0.59	8.03	0.53	7.06
Asure Software Inc	ASUR	0.96	0.27	0.11	0.25	0.40	0.65	0.64	0.10	0.62	2.89	2.40	2.59	2.29
AXT Inc	AXTI						1.20	1.05	0.24	0.90	2.11	-1.38	1.99	-1.59
Continental Materials Corp	CUO	0.83	0.81	0.94	0.92	0.87	0.45	0.47	0.09	0.45	1.37	10.58	2.49	2.45
CPI Aerostructures Inc	CVU	0.97	0.98	0.96	0.98	0.97	0.85	0.76	0.10	0.48	1.77	-1.23	5.71	7.13
Daily Journal Corp	DJCO				0.79	0.79	0.60	0.63	0.15	0.41	0.99	-1.47	0.93	-1.67
EXACT Sciences Corp	EXAS	0.99	0.99	0.98	0.99	0.99	1.15	1.09	0.15	1.54	0.44	1.41	0.45	1.12
EXFO Inc	EXFO	0.99	1.00	1.00		1.00	1.10	1.02	0.10	0.38	3.98	3.73	3.57	3.56
National Beverage	FIZZ			0.58	0.78	0.68	0.80	0.80	0.05	0.35	0.20	1.24	0.18	1.24
Full House Resorts Inc	FLL		0.70	0.55	0.55	0.60	0.85	0.86	0.16	0.72	2.86	5.36	2.58	6.55
Gaia Inc.	GAIA						1.00	1.02	0.29	0.62	24.56	-2.21	22.18	-2.26
Heska Corporation	HSKA				0.99	0.99	0.00	0.63	0.04	0.62	1.71	-2.36	5.54	3.82
ORBCOMM Inc	ORBC	0.99	0.97	0.97	0.81	0.94	1.00	1.02	0.17	0.33	10.37	-3.94	9.29	-3.75
XO Group Inc	XOXO						0.90	0.87	0.07	0.30	4.88	2.17	4.28	2.18
Average		88%	75%	64%	65%	74%	0.83	0.84	0.13	0.58	4.17	1.34	4.39	1.72
Standard Deviation		21%	30%	48%	48%	32%	0.31	0.19		0.32	6.18	4.16	5.48	3.54

Exhibit 6

AVERAGE REALIZED HISTORICAL RETURNS, US DEBT AND EQUITY MARKETS								
	U.S. Treasury			Corporate	Large Cap	Total US	Small Cap	
	Bills	In-T Debt	L-T Debt	Debt	Equities	Markets	Equities	Inflation
1920s	3.42	4.71	4.98	5.78	11.88	7.61	-5.49	-3.60
1930s	0.32	4.27	5.18	6.58	6.85	7.47	18.69	-1.43
1940s	0.53	1.61	2.70	2.59	14.45	14.36	29.69	5.46
1950s	2.02	2.48	1.41	4.96	17.72	16.78	15.31	2.44
1960s	4.27	4.05	1.45	2.74	9.02	9.16	17.91	2.69
1970s	6.80	5.78	4.11	5.05	10.38	11.21	21.25	6.91
1980s	8.58	12.75	14.51	14.78	14.63	13.48	10.86	4.18
1990s	4.74	7.71	11.00	9.44	18.39	18.31	18.58	2.06
2000s	2.20	5.76	7.15	7.69	3.63	4.86	12.79	2.15
2010s	0.06	2.25	7.26	7.42	12.92	12.78	14.17	1.62
1926-2016	3.43	5.28	5.97	6.72	11.95	11.77	16.57	2.88
1970-2016	4.89	7.45	9.01	9.20	11.74	11.81	14.94	3.57
1990-2016	2.87	5.85	8.56	8.25	10.91	11.20	13.97	2.06
Expected Inflation								1.80
Sample Period Long-Term Risk Free Rate								
2009 Forward							3.20	
2013 Forward							3.45	
Sample Period Market Returns (%)								
	Nominal		Inflation		Real			
1970-2016	11.81		3.57		8.24			
1990-2016	11.20		2.06		9.14			
Expected Future Market Returns (%)								
	Real Return		Inflation		Nominal			
1970-2016	8.24		1.80		10.04			
1990-2016	9.14		1.80		10.94			

SERVICE DATE
Jul 31, 2020

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of St. Croix Valley Natural Gas Company, Inc. for Authority
to Increase Rates for Natural Gas Service

5230-GR-108

FINAL DECISION

This is the Final Decision in the Class 1 proceeding conducted by the Public Service Commission of Wisconsin (Commission) on the application of the St. Croix Valley Natural Gas Company, Inc. (SCV) for authority to increase its retail natural gas rates. The application is APPROVED, as conditioned by this Final Decision.

Introduction

SCV applied to the Commission on June 28, 2019 for authority to increase retail natural gas rates by \$369,200, or 4.50 percent. SCV's last rate change was approved in docket 5230-GR-107 by Final Decision dated February 23, 2017. ([PSC REF#: 298374](#).) SCV cited increased operation and maintenance expenses as the contributing factor(s) for the rate increase request. The final overall rate change authorized is \$339,418 or 3.83 percent.

Pursuant to due notice, the Commission held a telephonic hearing at Madison and the SCV offices in River Falls on May 26, 2020. The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. SCV is the only party to the proceeding.

Findings of Fact

1. A reasonable estimate of average net investment rate base for the test year is \$3,502,359.

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2. SCV's present authorized rates for natural gas utility service will produce total operating revenues of \$8,891,158 which are less than SCV's revenue requirement of \$9,230,576 for the test year. SCV's present rates are unreasonable and unjust as they are insufficient to cover the application's test-year operating expense and to provide an opportunity for a reasonable return on utility investments.

3. The rate of return on average net investment rate base at current rates of 1.45 percent is unreasonable and inadequate.

4. A reasonable utility ratemaking capital structure for the test year consists of 60.00 percent equity, and 40.00 percent long-term debt.

5. A reasonable return on equity is 11.00 percent

6. SCV's cost of long-term debt is 4.76 percent. A reasonable return on average net investment rate base that will provide adequate interest coverage is 8.50 percent.

7. It is reasonable for SCV to continue to record the amount established in docket 5230-AF-100 as a regulatory asset and amortize it over a 29-year period, or \$5,859 per year.

8. It is reasonable for SCV to amortize the over-refunded 2018 and 2019 income tax savings of \$8,904 over a 4-year period, or \$2,226 per year, subject to true up in SCV's next rate proceeding.

9. It is reasonable for SCV to retain \$146,500 of protected excess deferred income taxes (EDIT) that were accrued from 1991 to 2011.

10. It is reasonable for SCV to amortize protected EDIT of \$96,100 that was accrued after 2011 over the life of the underlying assets, or \$4,178 for the 2020 test year.

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11. It is reasonable for SCV to offset unprotected EDIT of negative \$24,800 with the \$47,362 2005 Wisconsin Act 141 (Act 141) balance owed to ratepayers. The remaining Act 141 balance to be returned to ratepayers is \$22,562.

12. It is reasonable for SCV to record an annual conservation expense of \$81,106, which consists of estimated conservation expenditures of \$86,746 less the remaining Act 141 balance of \$22,562 amortized over a 4-year period, or \$5,641 per year. Further, it is reasonable to direct SCV to record these expense amounts annually until they are superseded by a Commission order authorizing a new conservation escrow accrual.

13. An increase in SCV's operating revenues for the test year of \$339,418 is necessary to generate an 8.50 percent return on average net investment rate base and to cover SCV's total cost of service.

14. It is reasonable for SCV to establish telemetry fees to recover the costs associated with operating telemetry equipment.

15. It is reasonable for SCV to establish a new firm service tariff for customers with usage greater than 125,000 therms.

16. The rates and rules in Appendix C are just and reasonable and will permit SCV to earn the necessary revenue requirement for the test year.

17. Energy conservation, renewable resources, or energy priorities listed in Wis. Stat. §§ 1.12 or 196.025 and their combination would not be a cost-effective, technically feasible, or environmentally sound alternative to the rate increase authorized in this Final Decision.

Conclusions of Law

1. SCV is a natural gas public utility as defined in Wis. Stat. § 196.01(5).

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2. The Commission has authority under Wis. Stat. §§ 196.025, 196.03, 196.20, and 196.37 to authorize SCV to establish natural gas rates and rules and in accordance with this Final Decision and to determine that the rates and rules in Appendix C are reasonable and just as a matter of law.

3. The Commission has authority under Wis. Stat. § 15.02(4) to delegate to the Administrator of the Division of Energy Regulation and Analysis those functions vested by law as enumerated above. It has delegated the authority to the Administrator of the Division of Energy Regulation and Analysis to issue a Final Decision in this matter.

Opinion

Applicant and its Business

SCV is a public natural gas utility, as defined in Wis. Stat. § 196.01(5). SCV provides service to approximately 8,674 customers in the cities of River Falls and Prescott, the Village of Hammond, and the townships of Hammond, Troy, Kinnickinnic, Clifton, and River Falls in Pierce and St. Croix counties in western Wisconsin.

Average Net Investment Rate Base

The average net investment rate base for the test year is as follows:

Natural Gas Utility Plant	\$10,168,300
Less: Accumulated Depreciation	6,028,700
Net Plant:	\$4,139,600
Plus: Materials and Supplies	62,149
Plus: Regulatory Assets	167,000
Less: Customer Advances	69,891
Less: Deferred Taxes	796,500
Net Investment Rate Base	\$3,502,359

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This rate base is reasonable and just.

Comparative Income Statement

Income statements showing revenues and expenditures estimated for the test year ending December 31, 2020, at present rates and at rates authorized in this Final Decision, are contained in Appendix B. Such income statements are reasonable and just for purposes of this proceeding. Appendix B also shows the percent change in revenues for the various rate classes at present and authorized rates. SCV's present rates will generate gross operating revenues of \$8,891,158, which results in an annual revenue deficiency of \$339,359. SCV's present rates are unreasonable and unjust because they produce inadequate revenues.

Amortization Expense

In docket 5230-AF-100, SCV requested Commission authorization to capitalize the \$169,914 payment to Wisconsin Gas LLC for construction of the delivery station in the Village of Hammond. ([PSC REF#: 356913](#).) SCV requested to treat the payment as a capital expenditure which would be recorded to Account 379, Measuring and Regulating Station Equipment – City Gate Check Stations. The account would be depreciated over 29 years. As an alternative, SCV proposed recording the payment as a deferred expense and requested an amortization period of 29 years to correspond with the life of other assets associated with the station. The Commission considered the request at its open meeting on April 11, 2019 and ordered SCV to record a regulatory asset and defer the capital expenditure to a future rate application. ([PSC REF#: 364711](#).) The Commission finds it reasonable that SCV continue to record the amount established in the order as a regulatory asset and amortize it over a 29-year period, or \$5,859 per year.

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Tax Reform

Income Statement Component

On December 22, 2017 the Tax Cuts and Jobs Act (TCJA) was signed into law with an effective date of January 1, 2018. The TCJA made significant changes to the Federal Tax Code and included changes to individual, business, and international tax provisions, which impacted all Wisconsin investor-owned utilities (IOU). Notable for Wisconsin IOUs, the TCJA reduced the corporate tax rate from a maximum of 35.00 percent under the existing graduated rate structure to a flat 21.00 percent rate for tax years beginning after 2017. In its May 24, 2018 Order in docket 5-AF-101 ([PSC REF#: 343223](#)), the Commission ordered the IOUs to implement a line item credit to reflect the difference in rates between the 21.00 percent income tax rate and the old income tax rate of 35.00 percent. In doing so, the Commission effectively restated each IOU's income statement at the lower tax rate and provided for credits in the amount needed to adjust the IOU's net income to its previously authorized amount. Each credit would then remain in place until the IOU's authorized revenue requirement incorporated the 21.00 percent income tax rate.

The Commission's Order in docket 5-AF-101 found "that the IOUs' current rates are unjust and unreasonable as a result of the TCJA" and stated the Commission's belief "that the tax savings should be returned to customers or otherwise used for the customers' benefit as soon as possible." ([PSC REF#: 343223](#).) As an interim solution, the Commission's Order directed SCV to issue bill credits for the income statement component savings. The Order did not explicitly establish an end date for those credits, stating simply "[t]he monthly, volumetric bill credits shall continue until further Commission action in this docket or Commission action in a future rate case." (*Id.* at 29.)

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Commission staff conducted a true-up of the income tax savings, including carrying costs at the short-term debt rate, with the bill credits issued during 2018 and 2019, and determined that SCV has over-refunded their income tax savings to ratepayers by \$8,904. The Commission finds it reasonable to allow SCV recovery of the over-refund by increasing revenue requirements over a 4-year period, or \$2,226 per year, subject to true-up in the next rate case proceeding.

Balance Sheet Component

The TCJA also required IOUs to revalue their accumulated deferred income taxes (ADIT) based on the reduced corporate tax rate. ADIT are the result of differences between tax laws and accounting methods, and a lower corporate tax rate generally creates EDIT.

EDIT are created due to the timing differences in computing income under tax laws and generally accepted accounting principle rules. Ordinarily, the tax expense incurred by utilities is comprised of current income tax and deferred income tax. Both taxes are recovered from the ratepayers via the revenue requirement. Current income tax is that which is paid to the tax agency in that year. Deferred tax is the tax that would be paid in a later year. When a change in tax rate occurs, the utility continues to collect tax at the old rates from ratepayers until the time the rates are corrected for the new tax rates. Simply put, EDIT are the excess deferred taxes collected from ratepayers.

The Internal Revenue Service (IRS) requires that the portion of EDIT that are related to the use of accelerated depreciation are amortized no faster than over the life of the underlying assets. If amortized faster, the IRS could consider it to be a normalization violation, and SCV could lose the right to use accelerated depreciation on future income tax returns. The EDIT that are subject to the normalization rules are referred to as “protected” EDIT. The rest of SCV’s EDIT are

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considered to be “unprotected” and may be amortized over a shorter time period or recognized immediately.

SCV reported protected EDIT balances of \$242,600. However, as Don Piepgras notes in his pre-filed testimony, \$146,500 of the protected EDIT were incurred from 1991 until 2011, during which the Commission had disallowed SCV from recovering the cost of income taxes through customer rates. ([PSC REF#: 371077](#).) From 1991 until 2007, SCV was structured as an S-Corporation. As an S-Corporation, SCV incurred no income tax liability, as the income taxes associated with SCV were paid through the personal income tax filings of the owners. As such, the Commission denied rate relief for income taxes. While SCV converted to a C-Corporation in 2007, SCV did not receive rate relief for income taxes until October 2011 in docket 5230-GR-106. ([PSC REF#: 153346](#).) As a result, the total EDIT contribution by SCV’s ratepayers between 2011 and the passage of the TCJA was \$96,100.

As noted above, EDIT are the excess deferred income taxes that are collected from customers by including the cost of income taxes into customer rates. Since EDIT results from income taxes that are paid by customers, the Commission would ordinarily find it reasonable for EDIT to be either returned to customers or otherwise used for the customer’s benefit. However, SCV has stated that the Commission had disallowed SCV from recovering the cost of income taxes through customer rates from 1991 until its most recent rate case in 2011. As SCV was a pass-through entity and solely responsible for income taxes incurred during that period of time, any EDIT resulting from that same period should be returned to SCV rather than their customers. It would be unreasonable for the Commission to order SCV to return those amounts to customers, as doing so would unjustly benefit customers at the expense of SCV. As such, the Commission finds it reasonable that SCV be allowed to retain \$146,500 of protected EDIT that were accrued from

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1991 to 2011. The Commission also finds it reasonable for SCV to amortize the remaining \$96,100 of protected EDIT over a 23-year period, or \$4,178 per year, based on the estimated life of the underlying assets.

SCV also reported unprotected EDIT balances of negative \$24,800, which SCV proposed to offset against the balance owed to ratepayers in their Act 141 balance sheet account. In SCV's previous rate case in docket 5230-GR-107, it was discovered that SCV was not using escrow accounting for its Act 141 expenditures, and stopped recording the associated amortization expense. The Commission ordered SCV to return to ratepayers \$109,990 of previously deferred Act 141 expenditures that should have continued being recorded, through an amortization expense over a 5-year period, or negative \$21,998 per year. ([PSC REF#: 298374.](#)) Commission staff conducted a true-up of Act 141 payments since the previous rate case and determined that SCV's balance owed to ratepayers as of December 31, 2019 was \$47,362.

In regards to unprotected EDIT, the Commission stated in its supplemental order to docket 5-AF-101 that "The Commission continues to find that all of the tax savings resulting from the TJCA should be returned to customers or otherwise used for the customers' benefit as soon as possible. As a result, the Commission will continue, until all of the savings have been addressed, to exercise its discretion in this docket and individual utility rate case proceedings to direct how these savings shall be returned or otherwise used for the benefit of customers" and stated the Commission's belief that "In the exercise of its discretion, the Commission is not bound to any single regulatory formula; it is permitted to make pragmatic adjustments, which may be called for by particular circumstance." ([PSC REF#: 373697.](#))

As the Commission did not state any specific regulatory formula, utilities have proposed several methods of returning their unprotected EDIT balances. One such method would be to

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issue monthly bill credits, or in the case of SCV, monthly bill charges to recover the unprotected EDIT owed from customers. However, when allocating such small balances across the individual rate classes, there is the potential that the dollar amount per class may be diluted to such an immaterial amount as to render bill charges either *de minimus* or impossible. To avoid this situation, SCV has proposed to offset the owed from customers with the remaining balance of previously deferred Act 141 expenditures. Offsetting the two balances allows SCV to utilize 100.00 percent of the unprotected balance sheet amounts in this rate case as ordered by the Commission (*Id.* at 8), while returning the remaining Act 141 balance owed to customers in a more timely manner. As the use of tax benefits in this manner provides an immediate and tangible benefit to both SCV and its customers, in this particular circumstance, the Commission finds it reasonable to allow SCV to offset the unprotected EDIT of negative \$24,800 with the remaining Act 141 balance of \$47,362. Thus, the remaining Act 141 balance to be returned to ratepayers is reduced to \$22,562.

Conservation

The revenue requirement for the test year includes annual conservation expenses consisting of estimated Act 141 payments less an amortization expense of the remaining Act 141 balance owed to ratepayers after partially offsetting the balance through the usage of unprotected EDIT noted above. Commission staff proposed to amortize the remaining Act 141 balance of \$22,562 over a 4-year period, or negative \$5,641 per year. The Commission finds it reasonable for SCV to record an annual conservation expense of \$81,106, which consists of estimated conservation expenditures of \$86,746 less the annual amortization expense amount of \$5,641. Further, the Commission finds it reasonable to direct SCV to record these expense amounts

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annually until they are superseded by a Commission order authorizing a new conservation escrow accrual. SCV should continue to account for its conservation expenditures on an escrow basis since the required Act 141 expenditure amount changes each year.

Capital Structure

Capital structure refers to the types and proportions of capital utilized in the organization, including common stockholders' equity, long-term debt, and short-term debt. The capital structure is a significant consideration with respect to the creditworthiness of the organization, and impacts its ability to access the capital markets when necessary at a reasonable cost. The capital costs and rate of return authorized as part of the revenue requirements must fairly compensate SCV for its debt service obligations during the test year and provide SCV's owners with a return on invested capital that fairly compensates for time preference and investment risk, and enable it to preserve and attract capital in its long-term operations.

SCV filed a capital structure consisting of 83.55 percent equity and 16.45 percent long-term debt. In determining an appropriate capital structure for SCV, the Commission considers the impact on customer rates and SCV's financial flexibility and creditworthiness at various levels of equity embedded in SCV's total capitalization. Commission staff conducted a financial analysis which included examination of SCV's capital structure, financial integrity, and risk profile on a standalone basis as well as relative to peers regulated by this Commission. In connection with its analysis, Commission staff determined that an imputed capital structure consisting of 60.00 percent equity and 40.00 percent long-term debt would be more comparable to SCV's regulated peer group.

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In instances where a given utility has more risk exposure than its peers, a higher equity ratio in the capital structure and/or a higher return on equity (ROE) may be justified. No material risk factors unique to SCV were identified which would support a higher equity ratio or ROE relative to its peers. Therefore, by applying a capital structure and rate of return comparable to SCV's peers for the purposes of calculating its revenue requirement, its owners are adequately compensated from a risk/reward perspective. It also protects SCV's customers from bearing the incremental cost of an excessive rate of return without receiving any incremental benefit, given the higher cost of equity capital relative to debt, as discussed below.

Based on the evidence in the record, the Commission finds that for the purpose of establishing just and reasonable rates, an appropriate imputed capital structure consists of 60.00 percent equity and 40.00 percent long-term debt.

Return on Equity and Cost of Capital

In reaching its determination as to the appropriate ROE, the Commission must balance the interests of equity owners and SCV's lenders with those of consumers, with due consideration to economic and financial conditions along with public policy considerations. Commission staff performed an independent financial review which included a sensitivity analysis to evaluate SCV's credit metrics and other measures of financial strength at various rates of return, and recommended that an ROE of 11.00 percent be authorized as a reasonable level to balance the needs of customers and investors. Commission staff also confirmed this ROE remains reasonable in comparison to the returns authorized for SCV's peers.

SCV's weighted average cost of capital (WACC) includes the aforementioned imputed capital structure and an embedded cost of long-term debt of 4.76 percent. These capitalization

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ratios and cost rates result in a composite cost of capital considered just and reasonable for setting rates in this proceeding of 8.50 percent, derived as follows:

Capital Structure Component	Percent	Cost Rate	Weighted Cost
Utility Common Equity	60.00%	11.00%	6.60%
Long-Term Debt	40.00%	4.76%	1.90%
Weighted Average Cost of Capital = Required Return on NIRB			8.50%

The WACC of 8.50 percent for SCV supports estimated pre-tax interest coverage of 6.99 times. This estimate reflects all appropriate Commission staff adjustments, and is a reasonable and just factor for use in translating SCV’s composite cost of capital into a return requirement.

Ratio and Rate of Return on Rate Base

In its application in this proceeding, SCV filed a Ratio of Net Investment Rate Base Plus Construction Work in Progress (CWIP) Divided by Capital Used Primarily for Utility Operations Plus Accumulated Deferred Investment Tax Credit (Ratio) of 104.81 percent. The Ratio is the mechanism in Wisconsin ratemaking to provide SCV sufficient return to finance its net working capital position and its CWIP balances. These items are not included in rate base but are necessary for providing utility service to customers. The WACC is divided by the Ratio to obtain the required return on net investment rate base.

To properly calculate the Ratio, utilities need to forecast their entire balance sheet for the bridge year and test year(s), including working capital accounts. However, smaller IOUs usually do not have the resources to provide this analysis. SCV filed a Ratio of 104.81 percent, but it did not provide adequate support for its estimate. Without the necessary information for the Ratio, Commission staff proposed using a Ratio of 100.00 percent, meaning that due to the information received being insufficient for proper analysis, Commission staff assumes that current assets are

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equal to current liabilities on average for the test year. Based on the aforementioned reasoning, the Commission finds that adjusting the Ratio to 100.00 percent and incorporating other cost of capital changes results in a reasonable return on net investment rate base of 8.50 percent.

Revenue Requirement

Based on the Commission’s determinations above, the Commission finds that an increase in gas sales revenue of \$339,418 is reasonable for the purpose of determining reasonable and just rates in this proceeding, and is calculated as follows:

Required Return on Net Investment Rate Base	8.50%
Net Investment Rate Base	\$3,502,359
Required Earnings	\$297,700
Earnings at Present Rates	50,787
Earnings Deficiency (Excess)	\$246,913
Revenue Deficiency to Provide for Earnings Adjusted for State and Federal Income Taxes	\$339,418
Sales Revenues at Present Rates	8,858,090
Total Sales Revenue at Proposed Rates	9,197,508
Other Operating Revenues	33,068
Total Revenue Requirement	\$9,230,576

Natural Gas Cost of Service

Commission staff prepared two cost-of-service studies (COSS), COSS A and COSS B, in order to inform the rate design and overall rate increase allocation decisions. COSS A can be considered a more “customer-oriented” study, whereas COSS B can be considered a more “commodity-oriented” study, and together, COSS A and COSS B help to establish a range of reasonableness for rate design. Commission staff designed the two COSS models (Ex.-PSC-Meulemans-1) based on Commission staff’s audited revenue requirement. These studies are consistent with the Commission’s policy and represent a guide to setting rates. The

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Commission finds that it is reasonable to continue its long-standing practice of relying on multiple COSS models, as well as other factors, such as customer bill impacts, when determining the final allocation of the natural gas revenue requirement.

Natural Gas Revenue Allocation, Rate Design, and Rates

Commission staff prepared a comprehensive revenue allocation and rate design proposal based on staff's audited revenue requirement. Commission staff's offered revenue allocation and rate design was intended to reflect the full range of COSS results and cost allocation presented in the record of this proceeding. (Ex.-PSC-Meulemans-2.)

As noted above, the Commission finds it is reasonable to continue its long-standing practice of relying on multiple COSS models, as well as other factors, such as customer bill impacts, when determining the final allocation of the revenue requirement. Based on the COSS evidence presented in the record, the Commission finds it reasonable to authorize the natural gas revenue allocation and natural gas rate design proposed by Commission staff in Ex.-PSC-Meulemans-2. The authorized rates and gas revenues appear in Appendix C. The Commission finds it reasonable to direct SCV to file final form tariff sheets consistent with those rates.

Telemetry Fees

SCV proposed to add an additional fee for customers that utilize telemetry equipment. In order to accommodate customers who are using telemetry equipment, SCV must purchase and maintain telemetry equipment. As the costs associated with the telemetry equipment and their maintenance are caused solely by telemetry customers, the Commission finds it reasonable for SCV to be allowed to directly recover the costs associated with operating and maintaining telemetry equipment. This methodology has been used by several other utilities in Wisconsin in

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order to recover costs associated with telemetry equipment. Further, as the industry and its technology evolve, it is important that utilities' operations adapt along with the technology in a way that does not create a significant financial burden on them. The Commission finds this proposal to be reasonable and has established telemetry fees that will recover the SCV's costs associated with operating telemetry equipment.

Review of Rate Classes for Large Commercial Customers

As part of the Order in docket 5230-GR-107, SCV was ordered to submit a proposal and supporting data for separating its current firm service (Cg-2) tariff into two separate tariffs. This was requested of SCV so that Commission staff could evaluate whether customers who have usage above 125,000 therms are incurring different costs than customers whose usage falls in the range of 30,000 to 125,000 therms. Commission staff reviewed SCV's proposal and supporting data and found that it is reasonable to establish a new firm service tariff for customers with usage greater than 125,000 therms. The Commission determines this new class aligns well with the current structure for non-firm service customers.

Effective Date

The Commission finds it reasonable for the authorized rate and tariff changes to take effect one day after the date of service, provided that these rates and tariff provisions are made available by that date to the public at locations where customer payments are accepted, on SCV's Internet site, or in a form and place that is otherwise readily accessible to the public. If these rate increases and tariff provisions are not made available to the public by that date, it is reasonable to require that they take effect on the date SCV makes them available at locations where customer

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payments are accepted, on SCV's Internet site, or in a form and place that is otherwise readily accessible to the public.

Order

1. The authorized rate and tariff changes shall take effect one day after the date of service, provided that these rate and tariff provisions are made available by that date to the public at locations where customer payments are accepted, on SCV's Internet site, or in a form and place that is otherwise readily accessible to the public. If these rate increases and tariff provisions are not made available to the public by that day, they shall take effect on the date SCV makes them available at locations where customer payments are accepted, on SCV's Internet site, or in a form and place that is otherwise readily accessible to the public.

2. SCV shall revise its existing rates and tariff provisions for natural gas service, substituting the authorized rate and tariff changes shown in Appendix C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

3. SCV shall inform the Commission, in writing within 20 days of the effective date of this Final Decision, of the date that SCV makes the authorized rates and rules effective.

4. SCV shall file tariffs consistent with this Final Decision.

5. SCV shall inform each customer of the new rates as required by Wis. Admin. Code § PSC 113.0406(1)(d).

6. SCV shall continue to record the amount established in 5230-AF-100 as a regulatory asset and amortize it over a 29-year period, or \$5,859 per year.

7. SCV shall amortize protected EDIT of \$96,100 over the life of the underlying assets, or \$4,178 per year.

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8. SCV shall amortize the 2018 and 2019 net tax savings of \$8,904 over a 4-year period, or \$2,226 per year, subject to true up in SCV's next rate proceeding.

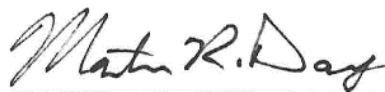
9. SCV shall record an annual conservation expense of \$81,106, which consists of estimated conservation expenditures of \$86,746 less the annual amortization expense amount of \$5,641 per year. SCV shall record these expense amounts annually until they are superseded by a Commission order authorizing a new conservation escrow accrual.

10. This Final Decision takes effect one day after the date of service.

11. Jurisdiction is retained.

Dated at Madison, Wisconsin, July 31, 2020.

For the Commission:

A handwritten signature in black ink that reads "Martin R. Day". The signature is written in a cursive, flowing style.

Martin R. Day
Administrator
Division of Energy Regulation and Analysis

MRD:SH:cmb:jlt:DL: 01736466

Attachments

See attached Notice of Rights

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PUBLIC SERVICE COMMISSION OF WISCONSIN
4822 Madison Yards Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

**NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE
TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE
PARTY TO BE NAMED AS RESPONDENT**

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.¹ The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

¹ See *Currier v. Wisconsin Dep't of Revenue*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

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APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN

(Not a party but must be served per Wis. Stat. § 227.53)

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Docket 5230-GR-108

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Appendix B

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St. Croix Valley Natural Gas Company, Inc
COMPARATIVE INCOME STATEMENT
TEST YEAR ENDED DECEMBER 31, 2020

	Present Rates	Proposed Rates	Dollar Change	Percent Change
OPERATING REVENUES				
RETAIL SALES OF GAS				
Rg-1 Residential Service	5,455,280	5,644,117	188,837	3.46%
RM-1 Residential - Multi Unit	286,420	294,056	7,636	2.67%
Cg-1 Small Commercial - Firm	1,508,283	1,545,004	36,721	2.43%
Ig-1 Small Commercial - Interruptible	61,710	69,210	7,500	12.15%
Cg-2 Large Commercial - Firm	417,961	428,202	10,241	2.45%
Ig-2 Large Commercial - Interruptible	437,963	499,057	61,094	13.95%
Cg-3 Large Commercial - Firm - New	580,113	595,380	15,267	2.63%
TS1-U Transportation Service	110,360	120,382	10,022	9.08%
Telemetered Customer Charge	-	2,100	2,100	0.00%
TOTAL RETAIL SALES OF GAS	8,858,090	9,197,508	339,418	3.83%
TOTAL ALL SALES OF GAS	8,858,090	9,197,508	339,418	3.83%
OTHER OPERATING REVENUE	33,068	33,068		
TOTAL ALL OPERATING REVENUES (A)	8,891,158	9,230,576		
OPERATING EXPENSE				
O. & M. EXPENSE				
Gas Supply Expenses				
City Gate Gas Purchases	-	-		
Other Gas Supply Expenses	5,970,552	5,970,552		
Total Gas Supply Expenses	5,970,552	5,970,552		
Distribution Expenses	724,089	724,089		
Customer Account Expenses	536,259	536,259		
Customer Service & Information Expenses	-	-		
Sales Expenses	-	-		
Admin. & General Expenses	958,273	958,273		
TOTAL O. & M. EXPENSE	8,189,172	8,189,172		
DEPRECIATION EXPENSE	398,610	398,610		
AMORTIZATION EXPENSE	5,859	5,859		
TAXES OTHER THAN INCOME	183,438	183,438		
INCOME TAXES	61,066	153,527		
DEFERRED INCOME TAXES	-	-		
TAX REFORM - NET 2018 & 2019 TRUE-UPS	\$2,226	\$2,226		
TOTAL OPERATING EXPENSES (B)	8,840,371	8,932,832		
NET OPERATING INCOME (A-B = C)	50,787	297,744		
AVG. NET INVEST. RATE BASE (D)	3,502,359	3,502,359		
RATE OF RETURN ON RATE BASE(C/ D)	1.45%	8.50%		
Requested Rate of Return	8.50%	8.50%		
Revenue Deficiency	339,359	(59)		
Retail Revenue Increase/(Decrease)		339,418		
% Retail Revenue Increase/(Decrease)		3.83%		

St. Croix Valley Natural Gas Company
Gas Revenue Summary for Test Year 2020

Rate Schedule	Present Revenue without Cost of Gas	Cost of Gas Revenue	Total Present Revenue	Authorized Revenue without Cost of Gas	Cost of Gas Revenue	Total Authorized Revenue	Revenue Change	Percent Change with Cost of Gas	Percent Change without Cost of Gas
Rg-1 Residential Service	\$ 2,051,255	\$ 3,404,025	\$ 5,455,280	\$ 2,238,807	\$ 3,405,310	\$ 5,644,117	\$ 188,837	3.5%	9.1%
Rm-1 Residential - Multi Unit	\$ 69,765	\$ 216,655	\$ 286,420	\$ 76,969	\$ 217,087	\$ 294,056	\$ 7,204	2.5%	10.3%
Total Residential Service	\$ 2,121,020	\$ 3,620,680	\$ 5,741,700	\$ 2,315,776	\$ 3,622,397	\$ 5,938,173	\$ 196,041	3.4%	9.2%
Cg-1 Small Commercial - Firm	\$ 414,998	\$ 1,093,285	\$ 1,508,283	\$ 452,879	\$ 1,092,125	\$ 1,545,004	\$ 36,721	2.4%	9.1%
Ig-1 Small Commercial - Interruptible	\$ 14,982	\$ 46,728	\$ 61,710	\$ 16,032	\$ 53,178	\$ 69,210	\$ 7,500	12.2%	7.0%
Total Small Commerical Service	\$ 429,980	\$ 1,140,013	\$ 1,569,993	\$ 468,911	\$ 1,145,303	\$ 1,614,214	\$ 44,221	2.8%	9.1%
Cg-2 Large Commercial - Firm	\$ 80,414	\$ 337,547	\$ 417,961	\$ 88,524	\$ 339,678	\$ 428,202	\$ 10,241	2.5%	10.1%
Ig-2 Large Commercial - Interruptible	\$ 103,972	\$ 333,991	\$ 437,963	\$ 111,343	\$ 387,714	\$ 499,057	\$ 61,094	14.0%	7.1%
Cg-3 Large Commercial - Firm - New	\$ 110,259	\$ 469,854	\$ 580,113	\$ 119,593	\$ 475,787	\$ 595,380	\$ 15,267	2.6%	8.5%
TS1-U Transportation Service	\$ 110,360	\$ -	\$ 110,360	\$ 120,382	\$ -	\$ 120,382	\$ 10,022	9.1%	9.1%
Total Large Commercial Service	\$ 405,005	\$ 1,141,392	\$ 1,546,397	\$ 439,842	\$ 1,203,179	\$ 1,643,021	\$ 96,624	6.2%	8.6%
Telemetry Charge	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,100	\$ 2,100		
Total Revenue	\$ 2,956,005	\$ 5,902,085	\$ 8,858,090	\$ 3,224,529	\$ 5,970,879	\$ 9,197,508	\$ 338,986	3.8%	9.1%

St. Croix Valley Natural Gas Company
Gas Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Residential Service - Rg-1			
Customer Charge	\$12.76	\$14.60	per month
Distribution Charge	\$ 0.1048	\$ 0.1060	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0110	\$ 0.0110	per therm
Residential - Multi Unit - RM-1			
Customer Charge	\$ 28.2000	\$ 32.5000	per month
Distribution Charge	\$ 0.0885	\$ 0.0961	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0110	\$ 0.0110	per therm
Small Commercial - Firm - Cg-1			
Customer Charge	\$21.95	\$26.00	per month
Distribution Charge	\$ 0.1004	\$ 0.1036	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0110	\$ 0.0110	per therm
Small Commercial - Interruptible - Ig-1			
Customer Charge	\$67.00	\$78.00	per month
Distribution Charge	\$ 0.0791	\$ 0.0843	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0094	\$ 0.0094	per therm
Large Commercial - Firm - Cg-2			
Customer Charge	\$40.00	\$55.00	per month
Distribution Charge	\$ 0.0944	\$ 0.1026	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0110	\$ 0.0110	per therm
Large Commercial - Interruptible - Ig-2			
Customer Charge	\$100.00	\$115.00	per month
Distribution Charge	\$ 0.0851	\$ 0.0913	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0060	\$ 0.0060	per therm
Transportation Service - TS1-U			
Customer Charge	\$100.00	\$115.00	per month
Large Commercial - Firm - New - Cg-3			
Customer Charge	\$40.00	\$76.00	per month
Distribution Charge	\$ 0.0944	\$ 0.1018	per therm
Gas Supply Acquisition Charge - System Supply Service	\$ 0.0110	\$ 0.0110	per therm
Base Average Cost of Gas			
Commodity Rate Charge (Comm)	\$ 0.3003	\$ 0.3085	per therm
Peak Day Demand Charge (D1)	\$ 0.1249	\$ 0.1548	per therm
Annual Demand Charge (D2)	\$ -	\$ 0.0434	per therm
Telemetry Charge			
Customer Charge	\$ -	\$ 25.00	per month
Act 141 Distribution Rate*			
Residential	\$ 0.00480	\$ 0.00436	per therm
Commercial	\$ 0.00870	\$ 0.00748	per therm

*Act 141 distribution rates are included in the above distribution service charges.

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Appendix C

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St. Croix Valley Natural Gas Company, Inc
 RESIDENTIAL BILL COMPARISON
 TEST YEAR ENDED DECEMBER 31, 2020

Residential Service (GR-1) - System Supply - Summer

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	\$ 12.76	\$ 14.60	\$ 1.84	14.4%
10	\$ 17.44	\$ 19.29	\$ 1.85	10.6%
20	\$ 22.11	\$ 23.98	\$ 1.86	8.4%
18	\$ 21.18	\$ 23.04	\$ 1.86	8.8%
40	\$ 31.47	\$ 33.36	\$ 1.89	6.0%
50	\$ 36.15	\$ 38.05	\$ 1.90	5.3%
75	\$ 47.84	\$ 49.77	\$ 1.93	4.0%
100	\$ 59.53	\$ 61.49	\$ 1.96	3.3%
200	\$ 106.30	\$ 108.38	\$ 2.08	2.0%
300	\$ 153.07	\$ 155.27	\$ 2.20	1.4%
500	\$ 246.61	\$ 249.05	\$ 2.44	1.0%

Residential Service (GR-1) - System Supply - Non-Summer

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	\$ 12.76	\$ 14.60	\$ 1.84	14.4%
10	\$ 18.99	\$ 20.84	\$ 1.85	9.8%
20	\$ 25.21	\$ 27.07	\$ 1.86	7.4%
30	\$ 31.44	\$ 33.31	\$ 1.88	6.0%
40	\$ 37.66	\$ 39.55	\$ 1.89	5.0%
50	\$ 43.89	\$ 45.79	\$ 1.90	4.3%
75	\$ 59.45	\$ 61.38	\$ 1.93	3.2%
100	\$ 75.01	\$ 76.97	\$ 1.96	2.6%
126	\$ 91.20	\$ 93.19	\$ 1.99	2.2%
200	\$ 137.26	\$ 139.34	\$ 2.08	1.5%
300	\$ 199.51	\$ 201.71	\$ 2.20	1.1%
500	\$ 324.01	\$ 326.45	\$ 2.44	0.8%

Residential Service (GR-1) - System Supply - Annual Total

Annual Therm Use	Annual Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	\$ 153.12	\$ 175.20	\$ 22.08	14.4%
50	\$ 183.29	\$ 205.43	\$ 22.14	12.1%
100	\$ 213.46	\$ 235.66	\$ 22.20	10.4%
200	\$ 273.81	\$ 296.13	\$ 22.32	8.2%
300	\$ 334.15	\$ 356.59	\$ 22.44	6.7%
400	\$ 394.50	\$ 417.06	\$ 22.56	5.7%
500	\$ 454.84	\$ 477.52	\$ 22.68	5.0%
750	\$ 605.70	\$ 628.68	\$ 22.98	3.8%
861	\$ 672.68	\$ 695.80	\$ 23.11	3.4%
1000	\$ 756.56	\$ 779.84	\$ 23.28	3.1%
1250	\$ 907.42	\$ 931.00	\$ 23.58	2.6%
1500	\$ 1,058.28	\$ 1,082.16	\$ 23.88	2.3%