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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200051-GU

PETITION FOR RATE INCREASE BY PEOPLES GAS SYSTEM.
_______________________________/

DOCKET NO. 20200166-GU

PETITION FOR APPROVAL OF 2020 DEPRECIATION STUDY BY PEOPLES GAS SYSTEM.
_______________________________/

DOCKET NO. 20200178-GU

PETITION FOR APPROVAL TO TRACK, RECORD AS A REGULATORY ASSET, AND DEFER INCREMENTAL COSTS RESULTING FROM THE COVID-19 PANDEMIC, BY PEOPLES GAS SYSTEM.
_______________________________/

VOLUME 3
PAGES 477 - 683

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER ANDREW GILES FAY

DATE: Thursday, November 19, 2020

TIME: Commenced: 11:00 a.m.
Concluded: 11:27 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
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I N D E X

WITNESSES

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of David J. Garret was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Peoples Gas System.	DOCKET NO. 20200051-GU
In re: Petition for approval of 2020 depreciation study by Peoples Gas System	DOCKET NO. 20200166-GU

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL

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PART ONE: COST OF CAPITAL

I. INTRODUCTION

Q. STATE YOUR NAME AND OCCUPATION.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

[1] Exhibit DJG-1.

Q. DESCRIBE THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC") in response to the petitions for rate increase and approval of the depreciation study by Peoples Gas System ("PGS" or the "Company"). Specifically, I address the cost of capital and fair rate of return for PGS in response to the direct testimony of Company witness Robert B. Hevert. I also address the Company's proposed depreciation rates in response to the direct testimony of Company witness Dane A. Watson, who conducted the Company's depreciation study. Because these two issues are voluminous, I have separated the executive summary and body of my testimony by issue: cost of capital and depreciation.

II. EXECUTIVE SUMMARY

A. Part One: Cost of Capital

Q. EXPLAIN THE CONCEPT OF THE "WEIGHTED AVERAGE COST OF CAPITAL."

A. The term "cost of capital" refers to the weighted average cost of all types of components within a company's capital structure, including debt and equity. Determining the cost of debt is relatively straight-forward. Interest cost rates on bonds are contractual, derived, "embedded costs" that are generally calculated by dividing total interest payments by the book value of outstanding debt. In contrast, determining the cost of equity is more complex. Unlike the known contractual cost of debt, there is no explicit "cost" of equity; thus, the cost of equity must be estimated through various financial models. The overall weighted average cost of capital ("WACC") includes the cost of debt and the estimated cost of equity. It is a "weighted average," because it is based upon the Company's relative levels of debt and equity, or "capital structure." Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be closely estimated. The basic WACC equation used in regulatory proceedings is presented as follows:

Equation 1:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right)C_D + \left(\frac{E}{D+E}\right)C_E$$

where:	$WACC$	=	*weighted average cost of capital*
	D	=	*book value of debt*
	C_D	=	*embedded cost of debt capital*
	E	=	*book value of equity*
	C_E	=	*market-based cost of equity capital*

Thus, the three components of the weighted average cost of capital include the following:

1. Cost of Equity
2. Cost of Debt
3. Capital Structure

The term "cost of capital" is necessarily synonymous with the "weighted average cost of capital," and the terms are used interchangeably throughout this testimony.

Q. DESCRIBE THE RELATIONSHIP BETWEEN THE COST OF EQUITY, REQUIRED RETURN ON EQUITY ("ROE"), EARNED ROE, AND AWARDED ROE.

A. While "cost of equity," "required ROE," "earned ROE," and "awarded ROE" are interrelated factors and concepts, they are all technically different from each other. The financial models presented in this case were created as tools for estimating the "cost of equity," which is synonymous to the "required ROE" that investors expect based on the amount of risk inherent in the equity investment. In other words, the cost of equity from the company's perspective equals the required ROE from the investor's perspective.

The "earned ROE" is a historical return that is measured from a company's accounting statements, and it is used to measure how much shareholders earned for investing in a company. A company's earned ROE is not the same as the company's cost of equity. For example, an investor who invests in a risky company may *require* a return on investment of 10%. If the company used the same estimates as the investor, then the company will estimate that its *cost* of equity is also 10%. If the company performs poorly and the investor *earns* a return of only 7%, this does not mean that the investor required only 7%, or that the investor will not still require a 10% return the following period. Thus, the cost of equity is not the same as the earned ROE.

Finally, the "awarded" return on equity is unique to the regulatory environment; it is the return authorized by a regulatory commission pursuant to legal guidelines. As discussed later in this testimony, the awarded ROE should be based on the utility's *cost* of equity. The relationship between the terms and concepts discussed thus far could be summarized in the following sentence: If the awarded ROE reflects a utility's cost of equity, then it should allow the utility to achieve an earned ROE that is sufficient to satisfy the required return of its equity investors. Thus, the "required" or "expected" return from an investor's standpoint is not simply what the investor wishes he could get. Likewise, the expected return of a utility investor has nothing to do with what the investor "expects" the ROE awarded by a regulatory commission to be. Rather, the expected return/cost of equity is estimated through objective, mathematical financial modeling based on risk.

Q. DESCRIBE THE COMPANY'S POSITION REGARDING ITS COST OF CAPITAL IN THIS CASE.

A. In this case, Mr. Hevert proposes an awarded return on equity of 10.75% for the Company.[2] Mr. Hevert relies on the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM"), and other models in making his recommendation.

Q. PLEASE DISCUSS THE COMPANY'S ROE PROPOSAL IN THE CONTEXT OF HISTORIC TRENDS IN AWARDED ROES FOR ELECTRIC UTILITIES.

A. Over the past thirty years, capital costs for all companies have generally declined. This is due in large part to generally declining interest rates over the same period. Likewise, awarded ROEs for electric utilities have also decreased since 1990. The graph below shows a trend in the annual awarded returns for gas utilities from 1990 to 2019.[3]

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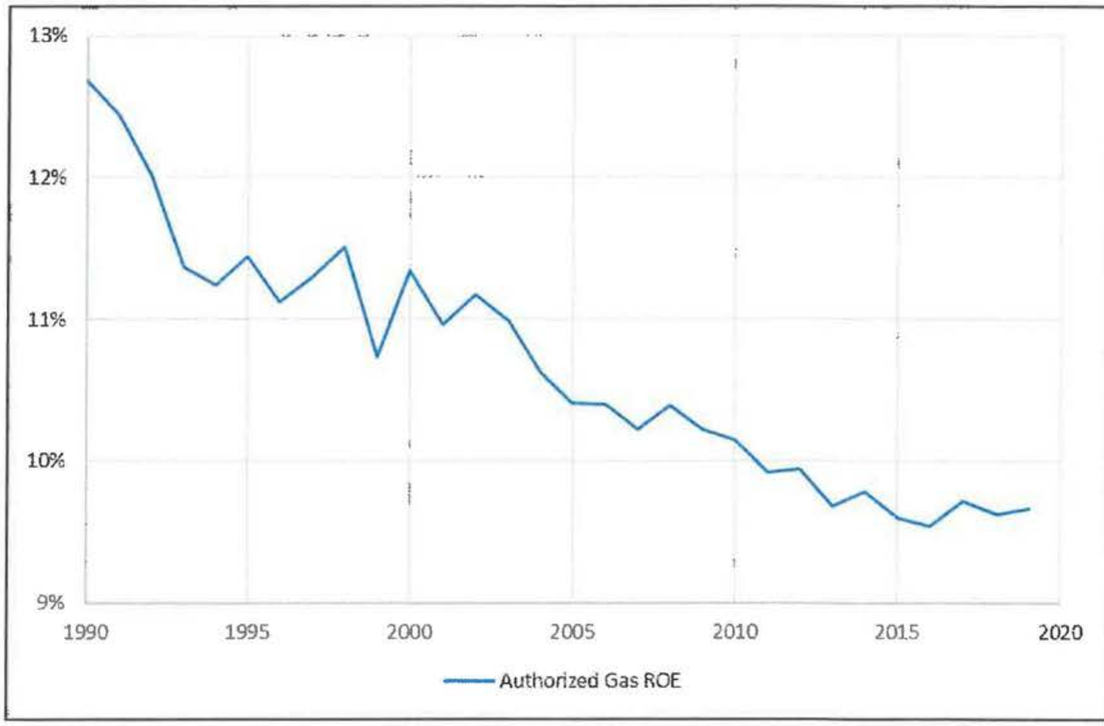
[2] Direct Testimony of Robert B. Hevert, p. 4, line 6.

[3] *See also* Exhibit DJG-14.

Figure 1:
Historic Awarded ROEs for Gas Utilities



As shown in the graph above, awarded ROEs for gas utilities have generally declined over the past 30 years.[4] To the extent the Commission is inclined to consider the awarded ROEs of other utilities in making its decision in this case, the Commission should also consider this downward trend in awarded ROEs.

Q. ARE YOU SUGGESTING THAT REGULATORS SHOULD SIMPLY SET ROES ACCORDING TO A NATIONAL AVERAGE OF AWARDED ROES?

A. No. As illustrated further in my testimony, there is strong evidence suggesting that regulators consistently award ROEs that are notably higher than utilities' actual cost of equity. This is likely due to the fact that over the past 30 years, interest rates and cost of

[4] *See* Exhibit DJG-14.

capital have declined at a faster rate than regulators' willingness to decrease awarded ROEs. In other words, awarded ROEs have appropriately been decreasing in accordance with declining capital costs; however, they have not decreased quickly enough to keep pace. To the extent regulators have been persuaded to conform to a national average of awarded ROEs when making their decisions in a particular case, it has contributed to this "lag" in awarded returns, which have effectively failed to track with declining interest rates over the same time period. In other words, whether objective market indicators influencing cost of equity are rising or falling, simply reverting to a national mean of awarded ROEs will effectively prevent those ROEs from properly rising and falling with the market indicators, such as interest rates. In today's economic environment, if a regulator awards an ROE that is equivalent to the national average, that awarded ROE will be above the market-based cost of equity for a regulated utility. Therefore, to suggest that the Commission simply set the Company's awarded ROE based on a national average would not result in a fair return, and it would promote the perpetuation of a national phenomenon of artificially inflated ROEs for regulated utilities.

Q. SUMMARIZE YOUR ANALYSES AND CONCLUSIONS REGARDING THE COMPANY'S COST OF EQUITY.

A. Analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility's cost of equity capital. In estimating the Company's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, I evaluated the results of the two most common financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. Applying reasonable inputs and assumptions to these models indicates that the Company's estimated cost of equity is approximately 6.9%.[5]

Q. YOUR COST OF EQUITY ESTIMATE FOR THE COMPANY IS NOTABLY LOWER THAN THE ROES TYPICALLY AWARDED IN UTILITY RATE CASES. PLEASE EXPLAIN YOURSELF.

A. Investors, company managers, and academics around the world have used models such as the CAPM for decades to closely estimate cost of equity. The CAPM in particular is not difficult to understand or calculate, and it requires only three inputs: the risk-free rate, beta, and the equity risk premium. The math involved in the CAPM is also straightforward. Here is the CAPM formula:

Cost of Equity = Risk-free Rate + Beta × Equity Risk Premium

Although these terms will be explained in more detail later, let us use Mr. Hevert's inputs for the risk-free rate and beta for this example. Mr. Hevert used a risk-free rate as high as 3.45% and an average beta as high as 0.897.[6] We can plug those numbers into the formula.

Cost of Equity = 3.45% + 0.897 × Equity Risk Premium

All we have remaining to complete the formula is one of the single most important numbers in the field of finance: The Equity Risk Premium ("ERP"). Fortunately, because this number is so important, a lot of experts estimate it. Thus, we can consider a variety of objective sources for the Equity Risk Premium, including expert surveys, scholars, and professional analysts. According to these experts, the Equity Risk Premium is

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[5] *See* Exhibit DJG-12.

[6] Exhibit No. (RBH-1), Document No. 6.

approximately 5.5%, and the highest ERP estimate I could find among these various experts is 6.0%.[7] Although I have no reason to believe that thousands of survey respondents and other experts have mistakenly underestimated this very important number, I recommend using 6.0% for the Equity Risk Premium to make absolutely sure we do not underestimate the Company's cost of equity. We can now complete the CAPM formula.

$$\textbf{Cost of Equity} = \mathbf{3.45\% + 0.897 \times 6.0\%}$$

The final cost of equity estimate from our Nobel-prize-winning CAPM is **8.8%**. However, if this was an assignment in a Finance 101 class, we would probably get a B- for this project. First, we have used a risk-free rate that is clearly too high. The current yield on 30-year Treasury bonds (a figure experts use for the risk-free rate) is only about 1.41%, and it hasn't been as high as 3.45% at all this year, or at any time during 2019.[8] Furthermore, we used an equity risk premium, which as discussed above is probably too high. Moreover, our reason for using a high Equity Risk Premium (". . . to make absolutely sure we do not underestimate the Company's cost of equity") is not a very good reason. That is not how professionals think about cost of equity and other important figures in finance and valuation.

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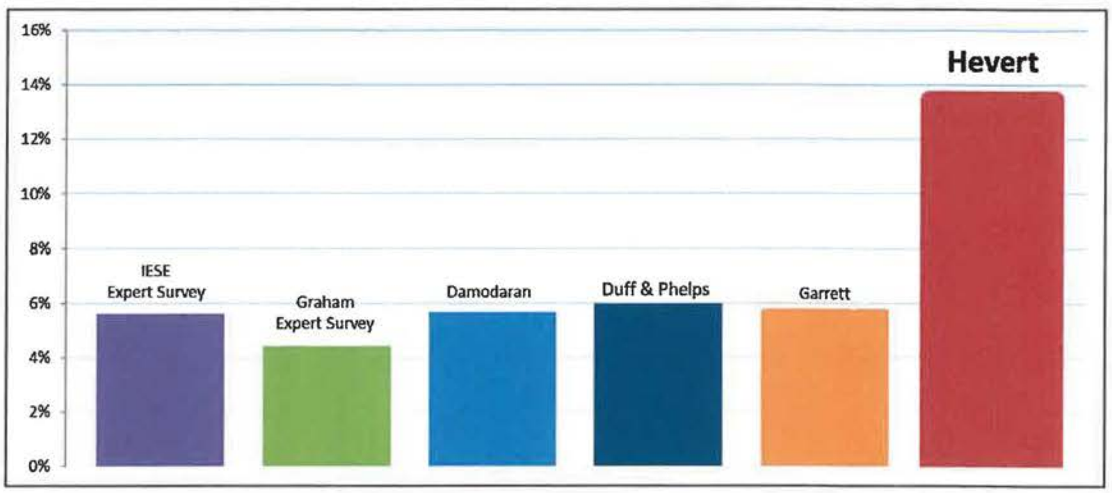
[7] *See* Exhibit DJG-10.

[8] Daily Treasury Yield Curve Rates, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/TextView.aspx?data=yieldYear&year=2019 .

Q. YOU USED MR. HEVERT'S INPUTS FOR THE RISK-FREE RATE (3.45%) AND BETA (0.897), BUT WHY DIDN'T YOU USE HIS INPUT FOR THE EQUITY RISK PREMIUM?

A. That's a good question. The following figure compares Mr. Hevert's equity risk premium estimate to the estimate of thousands of expert survey respondents, a highly-respected corporate finance advising firm, and arguably one of the world's leading experts on equity risk premium estimates.

Figure 2:
Equity Risk Premium Comparison



When compared with other independent, objective sources for the ERP, which do not have a wide variance, Mr. Hevert's ERP estimate is not realistic and is not supported by any independent, objective sources.

Q. BUT ARE YOU REALLY SURE 8.8% IS A REASONABLE ESTIMATE FOR PGS'S COST OF EQUITY, BECAUSE IT JUST SEEMS VERY LOW GIVEN THE FACT THAT REGULATORS TYPICALLY AWARD ROES THAT ARE ABOVE 9.5%?

A. Actually, a cost of equity estimate for PGS of 8.8% is clearly too high given the fact that we used an inexplicably high risk-free rate in our basic CAPM example presented above. Regardless, the fact that there is a discrepancy between this estimate and the *status-quo* awarded ROEs from regulators makes no difference. This is due to the fact that awarded ROEs and cost of equity are related, but very different, concepts. Awarded ROEs are decided by elected and appointed officials, influenced by politics, and negotiated in settlements. The *cost* of equity is influenced by none of these things (see Nobel-prize-winning formula discussed above). Indeed, "the market determines the cost of capital. Regulators don't."[9]

Q. IS THERE SOME WAY WE CAN TEST THE RESULTS OF OUR CAPM TO ASSESS ITS REASONABLENESS?

A. Yes. The CAPM has been used for decades by investors and company managers to make important investment and capital budgeting decisions (without the input of utility regulators). However, some utility ROE witnesses (such as Mr. Hevert in this case) have suggested that the CAPM underestimates cost of equity for firms in low-beta industries, such as utility companies. However, let's see what the CAPM results would be if we

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[9] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

simply assumed that utilities have a beta equal to 1.0. It is undisputed that the market (i.e., all the stocks) has a collective beta equal to 1.0, and the betas for utility stocks are consistently less than 1.0 (i.e., utilities are less risky than the average company in the market). So, you will see in our CAPM formula below that by using a beta of 1.0, we are effectively estimating the cost of equity of the entire stock market, which will be higher, by definition, than any cost of equity estimate for a low-risk utility company. In our CAPM cost of equity project for PGS discussed above, we got a grade of B- because we used an inexplicably high risk-free rate. This time, for our market cost of equity project, we will use a risk-free rate that actually corresponds with recent yields on 30-year Treasury bonds (or 1.4%).[10] In the interest of reasonableness, we will still use the highest ERP of 6% found from objective sources. Based on these inputs, our market cost of equity calculation is as follows:

$$\textbf{\textit{Market} Cost of Equity} = \mathbf{1.4\% + 1.0 \times 6.0\%}$$

Now, the result of our CAPM/market cost of equity estimate is **7.4%**. This means that if an investor bought the entire market, the expected return on that investment would currently be approximately 7.4%. Again, this is the market's cost of equity. Now, to answer the question of whether 8.8% was a reasonable cost of equity estimate for PGS, we can use the following logical steps: (1) It is undisputable that the cost of equity for a company with a beta of less than 1.0 will be less than the market cost of equity; (2) Since utilities consistently, and on average, have betas of less than 1.0, then the cost of equity for any utility company based on a proxy group of utilities must be less than 7.4%. Therefore,

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[10] *See* Exhibit DJG-7 and Exhibit DJG-13.

to answer the original question, a cost of equity estimate of 8.8% for PGS is unreasonably high. In fact, the highest reasonable cost of equity estimate for PGS would be 7.4%, and a more realistic cost of equity estimate for PGS is about 6.9%.[11]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. Pursuant to the legal and technical standards guiding this issue, the awarded ROE should be based on, or reflective of, the utility's cost of equity. As I explain in more detail below, the Company's estimated cost of equity is approximately 6.9%. However, these legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, in *Federal Power Commission v. Hope Natural Gas Co.*,[12] the U.S. Supreme Court ("Court" or "Supreme Court") found that, although the awarded return should be based on a utility's cost of capital, it also indicated that the "end result" should be just and reasonable. If the Commission were to award a return equal to the Company's estimated cost of equity of 6.9%, it would be accurate from a technical standpoint, and it would also significantly reduce the excess wealth transfer from ratepayers to shareholders that would otherwise occur if the Company's proposal were adopted. I recommend, however, the Commission award an ROE to the Company's shareholders that is remarkably higher than the PGS's actual cost of equity in this case. Specifically, I recommend an awarded ROE of 9.5%.

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[11] Exhibit DJG-12.

[12] *See Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). Here, the Court states that it is not mandating the various permissible ways in which the rate of return may be determined, but instead indicates that the end result should be just and reasonable. This is sometimes called the "end result" doctrine.

The ratemaking concept of "gradualism," though usually applied from the customer's standpoint to minimize rate shock, could also be applied to shareholders. An awarded return as low as 6.9% in any current rate proceeding would represent a substantial change from the "status quo," which as I prove later in this testimony, involves awarded ROEs that clearly exceed market-based cost of equity for utilities. However, while generally reducing awarded ROEs for utilities would move awarded returns closer to market-based costs and reduce part of the excess transfer of wealth from ratepayers to shareholders, I believe it is advisable to do so gradually. One of the primary reasons the Company's cost of equity is so low is because the Company is a very low-risk asset. In general, utility stocks are low-risk investments because movements in their stock prices are relatively involatile. If the Commission were to make a significant, sudden change in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile and would arguably be at odds with the *Hope* Court's "end result" doctrine. An awarded ROE of 9.5% represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be reasonable under the circumstances. An awarded ROE of 9.5% also represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.5% is over 250 basis points above the Company's market-based cost of equity. Nonetheless, it is clear that the Company's proposed ROE of 10.75% is excessive and unreasonable, as further discussed below.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROBLEMS YOU HAVE IDENTIFIED WITH MR. HEVERT'S TESTIMONY REGARDING COST OF EQUITY AND THE AWARDED ROE.

A. Mr. Hevert proposes a return on equity of 10.75%.[13] Mr. Hevert's recommendations are based on the CAPM, DCF Model, and other models. However, several of his key assumptions and inputs to these models violate fundamental, widely-accepted tenants in finance and valuation, while other assumptions and inputs are simply unrealistic. The key areas of concern are summarized as follows:

1. Terminal Growth Rate

In his DCF Model, Mr. Hevert's average long-term growth rate applied to the Company exceeds the long-term growth rate for the entire U.S. economy. In fact, Mr. Hevert's projected growth rates for his proxy companies are as high as 22%,[14] which is more than five times the projected U.S. GDP growth. It is a fundamental concept in finance that, in the long run, a company cannot fundamentally grow at a faster rate than the aggregate economy in which it operates; this is especially true for a regulated utility with a defined service territory. Thus, the results of Mr. Hevert's DCF Model are upwardly biased and are not reflective of current market conditions.

2. Equity Risk Premium

Mr. Hevert's estimate for the Equity Risk Premium, the single most important factor in estimating the cost of equity and a key input to the CAPM, is significantly higher

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[13] Direct Testimony of Robert B. Hevert, p. 2, line 19.

[14] Exhibit No. (RBH-1), Document No. 2.

than the estimates reported by thousands of experts across the country. In fact, there is no expert who estimates an ERP as high as Mr. Evert. In direct contradiction to Mr. Hevert's assertion that his risk premium analyses are "forward-looking,"[15] Mr. Hevert incorporates ERP data nearly 40 years old into some of his risk premium analyses.[16] Moreover, in estimating the ERP, Mr. Hevert did not follow conventional approaches, but rather conducted a DCF analysis on a sample of the entire market. This decision is especially problematic because Mr. Hevert used long-term growth rates as high as 64% in his analysis.[17] Specifically, Mr. Hevert estimated a long-term growth rate of 64% for Incyte Corp ("Incyte"), a biopharmaceutical company.[18] In 2019, Incyte reported earnings of $447 million.[19] If we apply Mr. Hevert's 64% annual growth rate to Incyte's 2019 earnings, in only 25 years Incyte's earnings would be more than $100 trillion, which would dwarf the GDP of the entire planet. Many of Mr. Hevert's other long-term growth estimates are similarly too high to be considered realistic. This example highlights why it is important not to overestimate long-term growth rates in either the DCF Model or the CAPM. As a result, Mr. Hevert's estimate of the most important factor in the CAPM is more than twice as high as the results estimated and reported by thousands of survey

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[15] *See e.g.*, Direct Testimony of Robert B. Hevert, p. 68, lines 22-23.

[16] Exhibit No. (RBH-1), Document No. 7.

[17] Exhibit No. (RBH-1), Document No. 4.

[18] *Id.*

[19] https://finance.yahoo.com/quote/INCY/financials?p=INCY

respondents and other experts.[20] Thus, Mr. Hevert's CAPM cost of equity estimate is overstated, unsupported, and unreasonable.

3. Bond Yield Plus Risk Premium Model

Mr. Hevert's own risk premium model is not market-based in that it considers awarded ROEs dating back to 1980[21] — a contradiction to Mr. Hevert's claim that his cost of equity models are "forward-looking."[22] As discussed in this testimony, awarded ROEs are consistently higher than market-based costs of equity for utility companies. Unlike the CAPM, which is a Nobel-prize-winning risk premium model found in nearly every fundamental textbook on finance and investments, the type of risk premium analysis offered by Mr. Hevert and other utility ROE witnesses are almost exclusively seen in the testimonies of utility ROE witnesses, and it results in cost of equity estimates unreflective of current market conditions. Given the reality that awarded ROEs have consistently exceeded utility market-based costs of equity for decades, any model that attempts to leverage the unbalanced relationship between awarded ROEs and any market-based factor (such as U.S. Treasury bonds in this case) will only serve to perpetuate the unfortunate discrepancy between awarded ROEs and utilities' actual costs of equity. Our purpose here should be to use objective, market-based models (the DCF and CAPM) to estimate the cost of equity so we can then use that estimate to help determine a fair awarded ROE. In contrast, Mr. Hevert's risk premium analysis relies on nothing more than an echo chamber

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[20] *See* Exhibit DJG-10.

[21] Exhibit No. (RBH-1), Document No. 7.

[22] *See e.g.*, Direct Testimony of Robert B. Hevert, p. 68, lines 22-23.

of outdated awarded ROEs that have no bearing on the Company's current, market-based cost of equity.

Q. WOULD THE RESULTS OF ANY OF MR. HEVERT'S COST OF EQUITY MODELS ACTUALLY EQUATE TO REASONABLE RESULTS FOR PGS'S AWARDED ROE?

A. Yes. Mr. Hevert conducted several versions of the DCF Model using various growth rates and lengths of time for average stock prices. Mr. Hevert's lowest DCF result was 7.47%.[23] Interestingly, this result is reflective of the market cost of equity estimate I presented above, which is the highest possible estimate for PGS's market-based cost of equity. If the Commission were to set PGS's cost of equity at Mr. Hevert's 7.47% DCF result, it would not only conform with the legal standards governing this issue, but it would also minimize the excess wealth transfer from ratepayers to shareholders relative to Mr. Hevert's other cost of equity estimates. Mr. Hevert's DCF Models also produced results of 7.52%, 7.70%, 8.03%, 8.15%, and 8.46%.[24] Each of these results are much closer to the Company's actual cost of equity than Mr. Hevert's other estimates and his ultimate recommendation.

Q. DESCRIBE THE HARMFUL IMPACT TO CUSTOMERS AND THE STATE'S ECONOMY IF THE COMMISSION WERE TO ADOPT THE COMPANY'S INFLATED ROE RECOMMENDATION.

A. When the awarded return is set significantly above the true cost of equity, it results in an inappropriate and excess transfer of wealth from ratepayers to shareholders beyond that

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[23] Exhibit No. (RBH-1), Document No. 2.

[24] *Id.*

which is required by law. This excess outflow of funds from Florida's economy would not benefit its businesses or citizens, nor would it result in better utility service. Instead, Florida businesses in the Company's service territory would be less competitive with businesses in surrounding states, and individual ratepayers would receive inflated costs for basic goods and services, along with higher utility bills.

B. Part Two: Depreciation

Q. SUMMARIZE THE KEY POINTS OF YOUR TESTIMONY REGARDING DEPRECIATION.

A. In the context of utility ratemaking, "depreciation" refers to a cost allocation system designed to measure the rate by which a utility may recover its capital investments in a systematic and rational manner. I employed a well-established depreciation system and used actuarial analysis and comparative analysis to analyze the Company's depreciable assets in order to develop reasonable depreciation rates in this case. In this case, I propose adjustments to the service lives and net salvage rates for several of PGS's distribution accounts. For each of these accounts, I propose a longer average remaining life, which results in lower depreciation rates and expense. My proposed adjustments would reduce PGS's proposed depreciation accrual by $5.5 million.[25]

Q. PLEASE SUMMARIZE YOUR SERVICE LIFE ADJUSTMENTS.

A. Based on the Company's historical accounting data, I formed observed life tables and observed survivor curves which provide historical retirement rates for the assets in each

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[25] *See* Exhibit DJG-15.

account. I then used standard survivor curves known as "Iowa curves" to project the remaining life in each account based on the historical data. According to the Company's own data, the service life estimates for several of the Company's distribution accounts were shorter than the service life otherwise indicated by the data. All else held constant, shorter service lives result in higher depreciation rates.

Q. PLEASE SUMMARIZE YOUR NET SALVAGE ADJUSTMENTS.

A. For several of its accounts, the Company has proposed sizeable decreases in its net salvage rates, which has an increasing effect on depreciation rates. While I do not dispute that there should be net salvage increases in these particular accounts, I would propose that the proposed amount of the increases be reduced based on the ratemaking concept of gradualism. Specifically, I recommend that the amount of the Company's proposed increases in net salvage rates in these accounts be reduced by 50%.

Q. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO THE COMPANY'S DEPRECIATION PARAMETERS.

A. The table below summarizes my proposed adjustments to service life (i.e., Iowa curve) and net salvage rates for the accounts at issue.

Figure 3:
Equity Risk Premium Comparison

		Current Parameters		Company Position		OPC Position	
Account		Iowa Curve	Net Sal	Iowa Curve	Net Sal	Iowa Curve	Net Sal
No.	Description	Type AL	Rate	Type AL	Rate	Type AL	Rate
376.00	Mains Steel	R2 - 55	-40%	R1.5 - 65	-60%	R1.5 - 65	-50%
376.02	Mains Plastic	R2 - 75	-25%	R2 - 75	-40%	R2 - 75	-33%
378.00	Meas & Reg Station Eqp Gen	R1 - 31	-5%	R1.5 - 40	-10%	R1 - 46	-10%
380.00	Services Steel	R0.5 - 50	-100%	R0.5 - 52	-150%	R0.5 - 57	-125%
380.02	Services Plastic	R1.5 - 55	-55%	R1.5 - 55	-80%	R1.5 - 64	-68%
382.00	Meter Installations	R0.5 - 43	-20%	R1 - 44	-30%	R1 - 44	-25%
384.00	House Regulator Installs	R4 - 27	-20%	R1 - 47	-30%	R1 - 47	-25%
385.00	Meas & Reg Station Eqp Ind	R4 - 32	0%	R3 - 37	-2%	R3 - 41	-2%

The details behind these adjustments are further discussed in the depreciation section of my testimony.

Q. PLEASE DESCRIBE WHY IT IS IMPORTANT NOT TO OVERESTIMATE DEPRECIATION RATES.

A. Under the rate base rate of return model, the utility is allowed to recover the original cost of its prudent investments required to provide service. Depreciation systems are designed to allocate those costs in a systematic and rational manner — specifically, over the service life of the utility's assets. If depreciation rates are overestimated (i.e., service lives are underestimated), it encourages economic inefficiency. Unlike competitive firms, regulated utility companies are not always incentivized by natural market forces to make the most economically efficient decisions. If a utility is allowed to recover the cost of an asset before the end of its useful life, this could incentivize the utility to unnecessarily replace the asset in order to increase its rate base, which results in economic waste. Thus, from a public policy perspective, it is preferable for regulators to ensure that assets are not depreciated before the end of their true useful lives. While underestimating the useful lives of depreciable assets could financially harm current ratepayers and encourage economic waste, unintentionally overestimating depreciable lives (i.e., underestimating depreciation rates) does not necessarily harm the Company financially. This is because if an asset's life is overestimated, there are a variety of measures that regulators can use to ensure the utility is not financially harmed. Thus, the process of depreciation strives for a perfect match between actual and estimated useful life. When these estimates are not exact, however, it is better that useful lives are not underestimated for these reasons.

PART ONE: COST OF CAPITAL

III. LEGAL STANDARDS AND THE AWARDED RETURN

Q. DISCUSS THE LEGAL STANDARDS GOVERNING THE AWARDED RATE OF RETURN ON CAPITAL INVESTMENTS FOR REGULATED UTILITIES.

A. In *Wilcox v. Consolidated Gas Co. of New York*, [26] the Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[27] Later in two landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, [28] the Court held:

> 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 . . . 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.

In *Federal Power Commission v. Hope Natural Gas Company*, [29] the Court expanded on the guidelines set forth in *Bluefield* and stated:

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[26] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[27] *Id.* at 48.

[28] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

[29] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (emphasis added).

> 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 returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

Q. IS IT IMPORTANT THAT THE AWARDED RATE OF RETURN BE BASED ON THE COMPANY'S ACTUAL COST OF CAPITAL?

A. Yes. The *Hope* Court makes it clear that the allowed return should be based on the actual cost of capital. Under the rate base rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[30]

[30] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

The models I have employed in this case closely estimate the Company's true cost of equity. If the Commission sets the awarded return based on my lower, and more reasonable rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return much *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to shareholders. As Dr. Morin notes:

> [I]f the allowed rate of return is greater than the cost of capital, 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 the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.[31]

Thus, it is important to understand that the *awarded* return and the *cost* of capital are different but related concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. On the other hand, the two concepts are different in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by a number of factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is driven by stock prices, dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities,

[31] Roger A. Morin, *New Regulatory Finance* 23-24 (Public Utilities Reports, Inc. 2006) (1994).

there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. DESCRIBE THE ECONOMIC IMPACT THAT OCCURS WHEN THE AWARDED RETURN STRAYS TOO FAR FROM THE U.S. SUPREME COURT'S COST OF EQUITY STANDARD.

A. As discussed further in the sections below, Mr. Hevert's recommended awarded ROE is much higher than the Company's actual cost of capital based on objective market data. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital.* If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from Florida customers to Company shareholders. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990.

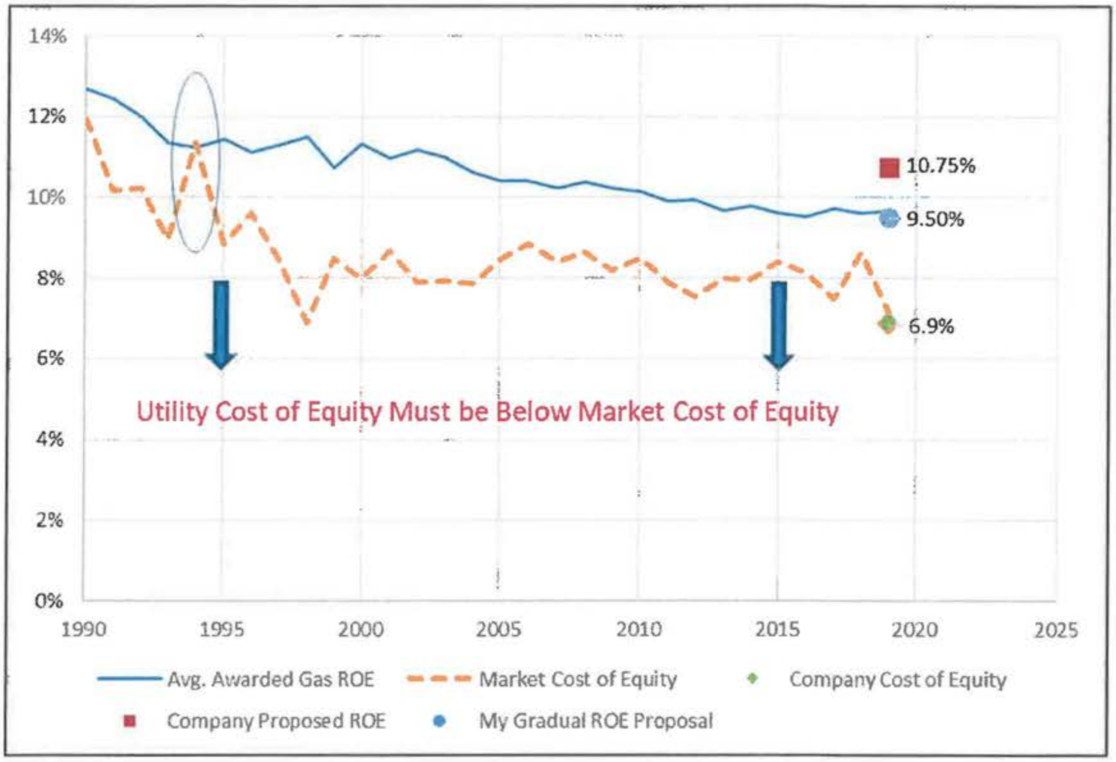
Q. ILLUSTRATE AND COMPARE THE RELATIONSHIP BETWEEN AWARDED UTILITY RETURNS AND MARKET COST OF EQUITY SINCE 1990.

A. As shown in the figure below, awarded returns for public utilities have been above the average required market return since 1990.[32] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is *less* than the market cost of equity. This is a fact, not an opinion. The graph below shows two trend lines. The top line is the average annual awarded returns since 1990 for U.S. regulated utilities. The bottom line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market. In other words, the required market return is essentially the cost of equity of the entire market. Since it is undisputed (even by utility witnesses) that utility stocks are less risky than the average stock in the market, then the utilities' cost of equity must be less than the market cost of equity.[33] Thus, awarded returns (the solid line) should generally be *below* the market cost of equity (the dotted line), since awarded returns are supposed to be based on true cost of equity.

[32] *See* Exhibit DJG-14.

[33] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

Figure 4:
Awarded ROEs vs. Market Cost of Equity



Because utility stocks are less risky than the average stock in the market, utility cost of equity is *below* market cost of equity (the dotted line in this graph). However, as shown in this graph, awarded ROEs have been consistently *above* the market cost of equity for many years. As shown in the graph, since 1990 there was only one year in which the average awarded ROE was below the market cost of equity — 1994. In other words, 1994 was the year that regulators awarded ROEs that were the closest to utilities' market-based cost of equity. In my opinion, when awarded ROEs for utilities are below the market cost of equity, they more closely conform to the standards set forth by *Hope* and *Bluefield* and minimize the excess wealth transfer from ratepayers to shareholders. The graph also shows the current discrepancy between awarded ROEs and market cost of equity along with the various positions in this case. In this case, Mr. Hevert's proposal of a 10.75% ROE is about 400 basis points above the Company's cost of equity of about 6.9%. As discussed previously, my recommended ROE of 9.5% represents a gradual move towards actual cost, is reasonable under the circumstances, and is in accord with the decisions of the U.S. Supreme Court.

Q. HAVE OTHER ANALYSTS COMMENTED ON THIS NATIONAL PHENOMENON OF AWARDED ROES EXCEEDING THE MARKET-BASED COST EQUITY FOR UTILITIES?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[34] Specifically, Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, *A Random Walk Down Wall Street*.
>
> 2. Institutions like pension funds are validating [the first point] by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[35]

[34] Steve Huntoon, "Nice Work If you can Get It," Public Utilities Fortnightly (Aug. 2016).

[35] *Id.*

In a follow-up article analyzing and agreeing with Mr. Huntoon's findings, Leonard Hyman and William Tilles found that utility equity investors expect about a 7.5% annual return.[36]

Other scholars have also observed that awarded ROEs have not appropriately tracked with declining interest rates over the years, and that excessive awarded ROEs have negative economic impacts. In a 2017 white paper, Charles S. Griffey stated:

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[37]

It is interesting that both Mr. Huntoon and Mr. Griffey use the word "sticky" in their articles to describe the fact that awarded ROEs have declined at a much slower rate than interest rates and other economic factors resulting in a decline in capital costs and expected returns on the market. It is not hard to see why this phenomenon of sticky ROEs has occurred. Because awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country, the average awarded returns effectively fail to adapt to true market conditions, and regulators seem reluctant to deviate from the average. Once utilities and regulatory commissions become accustomed to awarding rates of return higher than

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[36] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

[37] Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017).

market conditions actually require, this trend becomes difficult to reverse. Nevertheless, the fact is that utility stocks are *less risky* than the average stock in the market, and thus, awarded ROEs should be less than the expected return on the market. However, that is rarely the case. "Sooner or later, *regulators may see the gap between allowed returns and cost of capital*."[38]

Q. SUMMARIZE THE LEGAL STANDARDS GOVERNING THE AWARDED ROE ISSUE.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following legal principles:

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the Court understands one of the most basic, fundamental concepts in financial theory: the more (less) risk an investor assumes, the more (less) return the investor requires. Since utility stocks are very low risk, the return required by equity investors should be relatively low. I have used financial models in this case to closely estimate PGS' cost of equity, and these financial models account for risk. The public utility industry is one of the least risky industries in the entire country. The cost of equity models confirm this fact in that they

[38] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016) (emphasis added).

produce relatively low cost of equity results. In turn, the awarded ROE in this case should reflect the fact that the Company is a low-risk firm.

2. The awarded return should be sufficient to assure financial soundness under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that even under relatively inefficient management a utility could remain financially sound. Therefore, regulatory commissions should strive to set the awarded return to a regulated utility at a level based on accurate market conditions to promote prudent and efficient management and minimize economic waste.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. DISCUSS YOUR APPROACH TO ESTIMATING THE COST OF EQUITY IN THIS CASE.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the Discounted Cash Flow Model ("DCF

Model") and the Capital Asset Pricing Model ("CAPM"). The specific inputs and calculations for these models are described in more detail below.

Q. PLEASE EXPLAIN WHY MULTIPLE MODELS ARE USED TO ESTIMATE THE COST OF EQUITY.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. PLEASE DISCUSS THE BENEFITS OF CHOOSING A PROXY GROUP OF COMPANIES IN CONDUCTING COST OF CAPITAL ANALYSES.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly-traded company. There are advantages, however, to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly-traded firms, such as stock prices and dividends.

Q. DESCRIBE THE PROXY GROUP YOU SELECTED IN THIS CASE.

A. In this case, I chose to use the same proxy group used by Mr. Hevert. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.[39] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving the Company's cost of equity estimate in this case.

V. <u>RISK AND RETURN CONCEPTS</u>

Q. DISCUSS THE GENERAL RELATIONSHIP BETWEEN RISK AND RETURN.

A. Risk is among the most important factors for the Commission to consider when determining the allowed return. Thus, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

[39] *See* Exhibit DJG-2.

Q. DISCUSS THE DIFFERENCES BETWEEN FIRM-SPECIFIC RISK AND MARKET RISK.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[40] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[41]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share and the company filed bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational,

[40] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

[41] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because his portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. CAN INVESTORS EASILY MINIMIZE FIRM-SPECIFIC RISK?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[42] If someone irrationally invested all their funds in one firm, they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[43]

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[42] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179-80 (3rd ed., South Western Cengage Learning 2010).

[43] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[44] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. IS IT WELL-KNOWN AND ACCEPTED THAT, BECAUSE FIRM-SPECIFIC RISK CAN BE EASILY ELIMINATED THROUGH DIVERSIFICATION, THE MARKET DOES NOT REWARD SUCH RISK THROUGH HIGHER RETURNS?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

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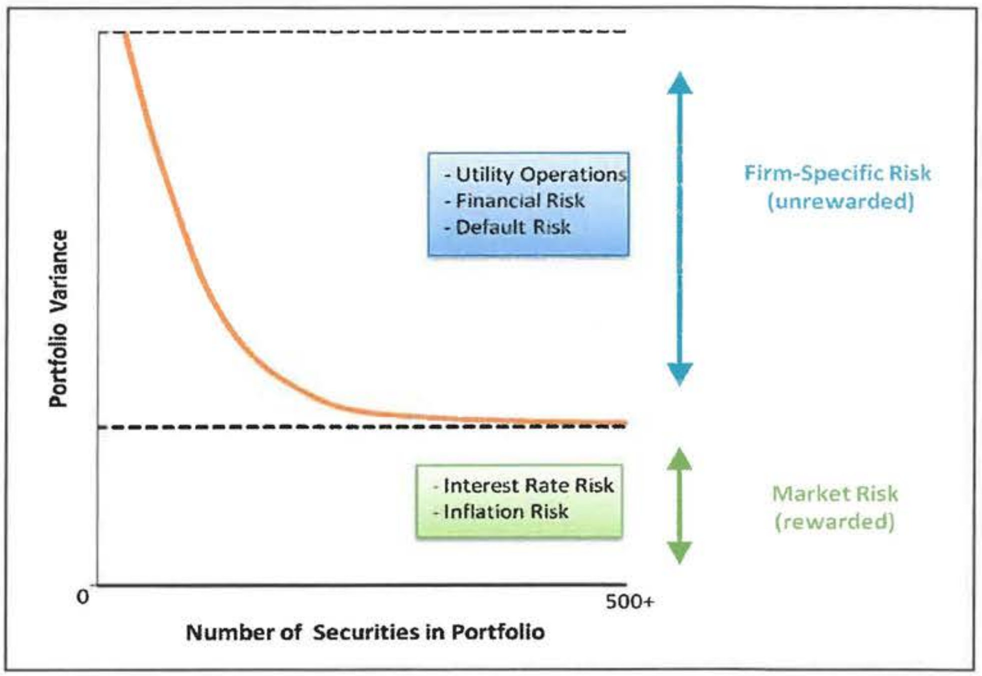
[44] *Id.*

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[45]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

Figure 5:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market

[45] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

and is thus the primary type of risk the Commission should consider when determining the allowed return.

Q. DESCRIBE HOW MARKET RISK IS MEASURED.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[46] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[47]

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[46] *Id.* at 180-81.

[47] Though it will be discussed in more detail later, Exhibit DJG-8 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

Q. ARE PUBLIC UTILITIES CHARACTERIZED AS DEFENSIVE FIRMS THAT HAVE LOW BETAS, LOW MARKET RISK, AND ARE RELATIVELY INSULATED FROM OVERALL MARKET CONDITIONS?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[48] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[49] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[50]

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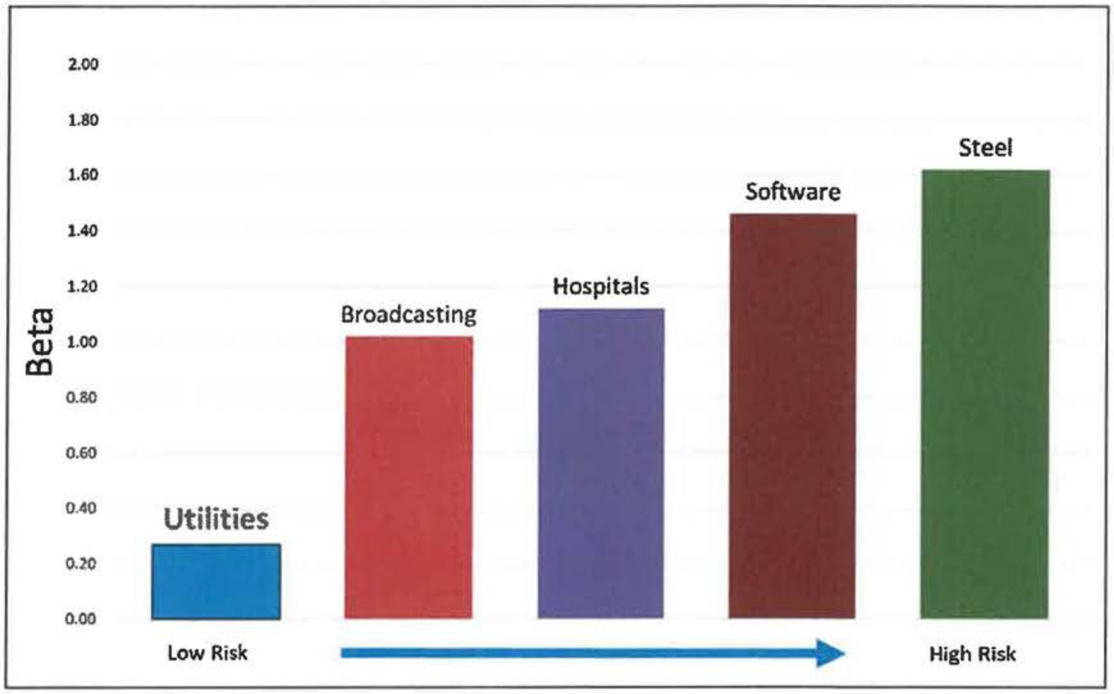
[48] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

[49] *Id.* at 383.

[50] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

Figure 6:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not widely fluctuate. So, while it is recognized and accepted that utilities are defensive firms that experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Company's awarded return.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") MODEL.

A. The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Exhibit DJG 25, Appendix A. For this case, I chose to use the Quarterly Approximation DCF Model.

Q. DESCRIBE THE INPUTS TO THE DCF MODEL.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

A. Stock Price

Q. HOW DID YOU DETERMINE THE STOCK PRICE INPUT OF THE DCF MODEL?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[51] Analysts sometimes rely on average stock prices for longer periods (e.g.,

[51] Exhibit DJG-3.

60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[52] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. WHY DID YOU USE A 30-DAY AVERAGE FOR THE CURRENT STOCK PRICE INPUT?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing

[52] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[53]

B. Dividend

Q. DESCRIBE HOW YOU DETERMINED THE DIVIDEND INPUT OF THE DCF MODEL.

A. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. I obtained the most recent quarterly dividend paid for each proxy company.[54] The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Thus, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

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[53] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[54] Exhibit DJG-4. Nasdaq Dividend History, available at http://www.nasdaq.com/quotes/dividend-history.aspx.

Q. DOES THE QUARTERLY APPROXIMATION DCF MODEL RESULT IN THE HIGHEST COST OF EQUITY IN THIS CASE RELATIVE TO OTHER DCF MODELS, ALL ELSE HELD CONSTANT?

A. Yes. The DCF Model I employed in this case results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the quarterly compounding of dividends inherent in the model. In essence, the Quarterly Compounding DCF Model I used results in the *highest* cost of equity estimate, all else held constant.

Q. ARE THE STOCK PRICE AND DIVIDEND INPUTS FOR EACH PROXY COMPANY A SIGNIFICANT ISSUE IN THIS CASE?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. Hevert, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between my DCF Model and Mr. Hevert's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. Growth Rate

Q. SUMMARIZE THE GROWTH RATE INPUT IN THE DCF MODEL.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input must be estimated. As a result, the growth rate is often the most contentious DCF input in utility rate cases. The DCF model used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Thus, the growth rate term in the constant growth DCF model is often called the "constant," "stable," or "terminal" growth rate. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the terminal growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet apparently most misunderstood aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I have devoted a more detailed explanation of this issue in the following sections, which are organized as follows:

(1) The Various Determinants of Growth

(2) Reasonable Estimates for Long-Term Growth

(3) Quantitative vs. Qualitative Determinants of Utility Growth: Circular References, "Flatworm" Growth, and the Problem with Analysts' Growth Rates

(4) Growth Rate Recommendation

1. <u>The Various Determinants of Growth</u>

Q. DESCRIBE THE VARIOUS DETERMINANTS OF GROWTH.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on long-term growth rates, which are discussed in the following section.

That is not to say that these growth determinants cannot be considered when estimating long-term growth; however, as discussed below, long-term growth must be constrained much more than short-term growth, especially for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the source of confusion in this area.

1. Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[55]

2. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. A more detailed discussion of analyst growth rates, including the problems with using them in the DCF Model to estimate utility cost of equity, is provided in a later section.

[55] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

3. Fundamental Determinants of Growth

Fundamental growth determinants refer to firm-specific financial metrics that arguably provide better indications of near-term sustainable growth. One such metric for fundamental growth considers the return on equity and the retention ratio. The idea behind this metric is that firms with high ROEs and retention ratios should have higher opportunities for growth.[56]

Q. DID YOU USE ANY OF THESE GROWTH DETERMINANTS IN YOUR DCF MODEL?

A. No. Primarily, these growth determinants discussed above would provide better indications of short to mid-term growth for firms with average to high growth opportunities. However, utilities are mature, low-growth firms. While it may not be unreasonable on its face to use any of these growth determinants for the growth input in the DCF Model, we must keep in mind that the stable growth DCF Model considers only *long-term* growth rates, which are constrained by certain economic factors, as discussed further below.

2. Reasonable Estimates for Long-Term Growth

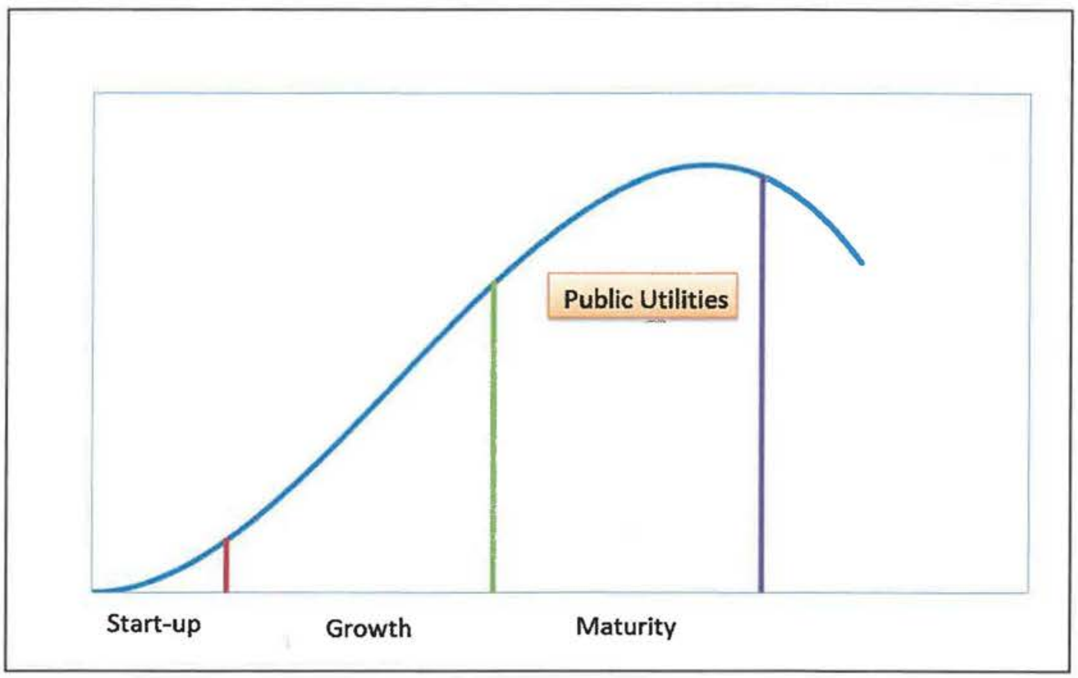
Q. DESCRIBE WHAT IS MEANT BY LONG-TERM GROWTH.

A. In order to make the DCF a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash

[56] *Id.* at 291-292.

flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being constant. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "terminal," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by the customer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 7:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate. Because utilities are in their maturity stage, their real growth opportunities are primarily limited to the population growth within their defined service territories, which is usually less than 2%.

Q. IS IT TRUE THAT THE TERMINAL GROWTH RATE CANNOT EXCEED THE GROWTH RATE OF THE ECONOMY, ESPECIALLY FOR A REGULATED UTILITY COMPANY?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[57] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran:

> "If a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[58]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is *less* than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing

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[57] *See generally* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[58] *Id.*

markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross domestic product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%, which includes an inflation rate of 2%.[59] For mature companies in mature industries, such as utility companies, the terminal growth rate will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, PGS's terminal growth rate is realistically between 2% and 4%.

Q. IS IT REASONABLE TO ASSUME THAT THE TERMINAL GROWTH RATE WILL NOT EXCEED THE RISK-FREE RATE?

A. Yes. In the long term, the risk-free rate will converge on the growth rate of the economy. For this reason, financial analysts sometimes use the risk-free rate for the terminal growth rate value in the DCF model.[60] I discuss the risk-free rate in further detail later in this testimony.

Q. PLEASE SUMMARIZE THE VARIOUS LONG-TERM GROWTH RATE ESTIMATES THAT CAN BE USED AS THE TERMINAL GROWTH RATE IN THE DCF MODEL.

A. The reasonable long-term growth rate determinants are summarized as follows:

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[59] Congressional Budget Office – The 2019 Long-Term Budget Outlook p. 54, https://www.cbo.gov/publication/55331.

[60] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 307 (3rd ed., John Wiley & Sons, Inc. 2012).

1. Nominal GDP Growth
2. Inflation
3. Current Risk-Free Rate

Any of the foregoing growth determinants could provide a reasonable input for the terminal growth rate in the DCF Model for a utility company, including PGS.[61] In general, we should expect that utilities will, at the very least, grow at the rate of projected inflation. However, the long-term growth rate of any U.S. company, especially utilities, will be constrained by nominal U.S. GDP growth.

3. Qualitative Growth: The Problem with Analysts' Growth Rates

Q. DESCRIBE THE DIFFERENCES BETWEEN "QUANTITATIVE" AND "QUALITATIVE" GROWTH DETERMINANTS.

A. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using various figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve a sustainable growth in earnings. Therefore, it is important to begin the analysis of PGS' growth rate with this simple, qualitative question: How is this regulated utility going to achieve a sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers

[61] Any extraordinary growth and additional risk resulting from PGS's discretionary venture into providing liquefied natural gas (LNG) services to end users in domestic and foreign markets may not be properly attributable to its regulated operations.]

depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot engage in these potential growth opportunities.

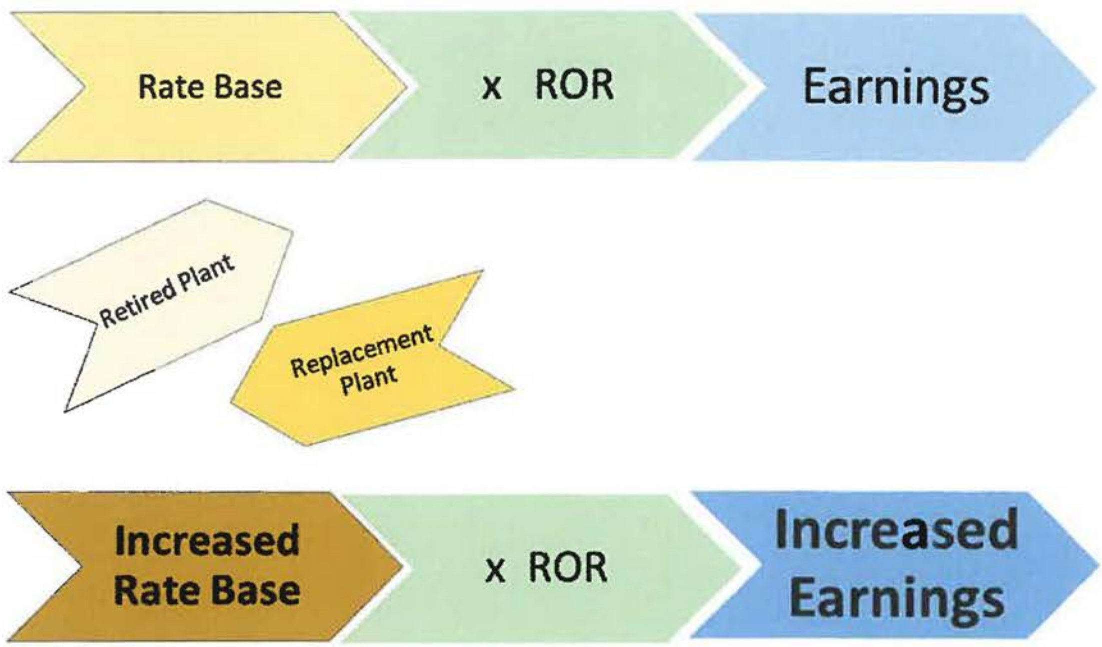
Q. WHY IS IT ESPECIALLY IMPORTANT TO EMPHASIZE REAL, QUALITATIVE GROWTH DETERMINANTS WHEN ANALYZING THE GROWTH RATES OF REGULATED UTILITIES?

A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are (1) rate base and (2) the awarded ROE. I will discuss each factor further below. It is important to keep in mind that the ultimate objective of this analysis is to provide a foundation upon which to base the fair rate of return for the utility. Thus, we should strive to ensure that each individual component of the financial models used to estimate the cost of equity are also "fair." If we consider only quantitative growth determinants, it may lead to projected growth rates that are overstated and ultimately unfair, because they result in inflated cost of equity estimates.

Q. HOW DOES RATE BASE RELATE TO GROWTH DETERMINANTS FOR UTILITIES?

A. Under the rate base rate of return model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base. In short, utilities have a financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. Under these circumstances, utilities have been able to increase their rate bases by a far greater extent than what any concurrent increase in demand would have required. In other words, utilities "grew" their earnings by simply retiring old assets and replacing them with new assets. If the tail of a flatworm is removed and regenerated, it does not mean the flatworm actually grew. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of old plant with new plant does not increase market share, attract new customers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. This "flatworm growth" in earnings was merely the quantitative byproduct of the rate base rate of return model, and not an indication of real, fair, or qualitative growth. The following diagram illustrates this concept.

Figure 8:
Analysts' Earnings Growth Projections: The "Flatworm Growth" Problem

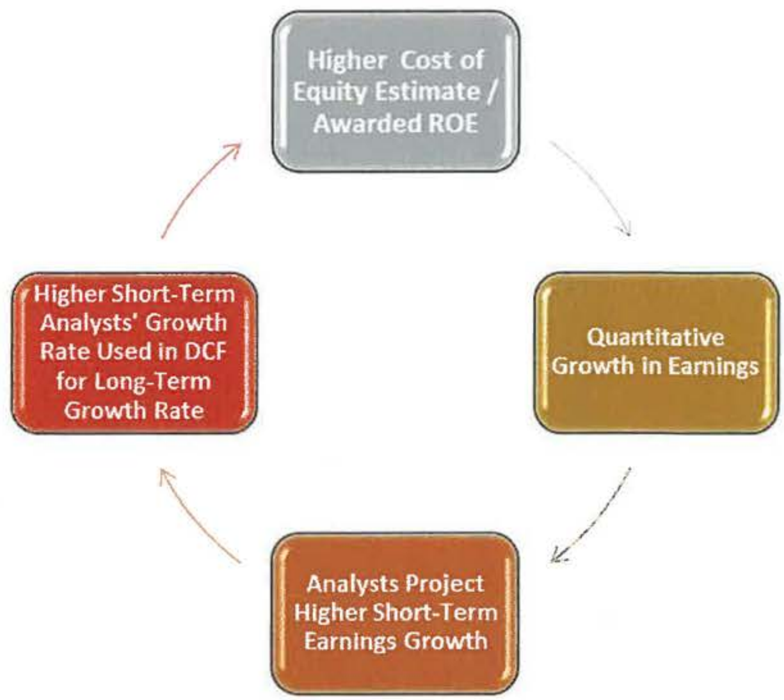


Of course, utilities might sometimes add new plant to meet a modest growth in customer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. PLEASE DISCUSS THE OTHER WAY IN WHICH ANALYSTS' EARNINGS GROWTH PROJECTIONS DO NOT PROVIDE INDICATIONS OF FAIR, QUALITATIVE GROWTH FOR REGULATED UTILITIES.

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (and they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle continues, as illustrated in the following figure:

Figure 9:
Analysts' Earnings Growth Projections: The "Circular Reference" Problem



Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real utility growth.

Q. ARE THERE ANY OTHER PROBLEMS WITH RELYING ON ANALYSTS' GROWTH PROJECTIONS?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and indisputable. Various institutional analysts, such as Zacks, Value Line, and Bloomberg, publish estimated projections of earnings growth for utilities. These estimates, however, are *short-term* growth rate projections, ranging from 3 – 10 years. Many utility ROE analysts, however, inappropriately insert these short-term growth projections into the DCF Model as *long-term* growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next 3 years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base (i.e., "flatworm" growth) or on an anticipated awarded return that is above market-based cost of equity (i.e., "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the *witness*, not the Bloomberg analyst that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the *long-term*, which is an unrealistic assumption.

4. <u>Long-Term Growth Rate Recommendation</u>

Q. DESCRIBE THE GROWTH RATE INPUT USED IN YOUR DCF MODEL.

A. I considered various qualitative determinants of growth for the Company, along with the maximum allowed growth rate under basic principles of finance and economics. The following chart shows the various long-term growth determinants discussed in this section.[62]

**Figure 10:
Terminal Growth Rate Determinants**

Terminal Growth Determinants	Rate
Nominal GDP	3.9%
Inflation	2.0%
Risk Free Rate	1.4%
Highest	**3.9%**

For the long-term growth rate in my DCF model, I selected the maximum, reasonable long-term growth rate of 3.90%, which means my model assumes that the Company's qualitative growth in earnings will match the nominal growth rate of the entire U.S. economy over the long run.

Q. PLEASE DESCRIBE THE FINAL RESULTS OF YOUR DCF MODEL.

A. I used the Quarterly Approximation DCF Model discussed above to estimate the Company's cost of equity capital. I obtained an average of reported dividends and stock prices from the proxy group, and I used a reasonable terminal growth rate estimate for the Company. Applying this model, my DCF cost of equity estimate for the Company is 7.3%.[63] As noted above, this estimate is likely at the higher end of the reasonable range due to my relatively high estimate for the long-term growth rate. That is, my long-term

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[62] Exhibit DJG-5.

[63] Exhibit DJG-6.

growth rate input assumes PGS' earnings will qualitatively grow at the same rate as the U.S. economy over the long-run — a very generous assumption.

D. Response to Mr. Hevert's DCF Model

Q. MR. HEVERT'S DCF MODEL YIELDED MUCH HIGHER RESULTS. DID YOU FIND ANY ERRORS IN HIS ANALYSIS?

A. Yes, I found several errors. Mr. Hevert's DCF Model produced cost of equity results as high as 13%.[64] The results of Mr. Hevert's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs.

1. Long-Term Growth Rates

Q. DESCRIBE THE PROBLEMS WITH MR. HEVERT'S LONG-TERM GROWTH INPUT.

A. Mr. Hevert used long-term growth rates in his proxy group as high as 22%,[65] which is more than five times higher than the projected, long-term nominal U.S. GDP growth (approximately 4.0%). This means Mr. Hevert's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Furthermore, Mr. Hevert used short-term, quantitative growth estimates published by analysts. As discussed above, these analysts' estimates are inappropriate to use in the DCF

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[64] Exhibit No. (RBH-1), Document No. 2.

[65] *Id.*

Model as long-term growth rates because they are estimates for short-term growth. For example, Mr. Hevert incorporated a 22% long-term growth rate for Northwest Natural Holding Company ("NWN"), which was reported by Value Line.[66] This means that an analyst from Value Line apparently thinks that NWN's earnings will quantitatively increase by 22% each year over the next *several* years. However, it is Mr. Hevert, not the Value Line analyst, who is suggesting to the Commission that NWN's earnings will grow by three times the amount of U.S. GDP growth every year for many decades into the future.[67] This assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. The growth rate assumptions used by Mr. Hevert for many of the proxy companies suffer from the same unrealistic assumptions.[68]

2. <u>Flotation Costs</u>

Q. WHAT ADDITIONAL ERRORS DID YOU FIND IN MR. HEVERT'S DCF ANALYSIS?

A. A proper DCF analysis considers the market-based stock price of a firm for the stock price input of the model. In this case, Mr. Hevert inappropriately considered flotation costs when making his awarded return recommendation.[69] When companies issue equity securities, they typically hire at least one investment bank as an underwriter for the securities.

[66] *Id.*

[67] *Id.* Technically, the constant growth rate in the DCF Model grows dividends each year to "infinity." Yet, even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

[68] *Id.*

[69] *See* Direct Testimony of Robert B. Hevert, p. 42.

"Flotation costs" generally refer to the underwriter's compensation for the services it provides in connection with the securities offering.

Q. DO YOU AGREE WITH MR. HEVERT THAT FLOTATION COSTS SHOULD BE CONSIDERED WHEN ASSESSING THE COMPANY'S COST OF EQUITY?

A. No. Mr. Hevert's flotation cost allowance is inappropriate for several reasons, as discussed further below.

1. Flotation costs are not actual "out-of-pocket" costs.

The Company has not experienced any out-of-pocket costs for flotation. Underwriters are not compensated in this fashion. Instead, underwriters are compensated through an "underwriting spread." An underwriting spread is the difference between the price at which the underwriter purchases the shares from the firm, and the price at which the underwriter sells the shares to investors.[70] Furthermore, PGS is not a publicly traded company, which means it does not issue securities to the public and thus would have no need to retain an underwriter. Accordingly, the Company has not experienced any out-of-pocket flotation costs, and if it has, those costs should be included in the Company's expense schedules.

2. The market already accounts for flotation costs.

When an underwriter markets a firm's securities to investors, the investors are well aware of the underwriter's fees. In other words, the investors know that a portion of the price they are paying for the shares does not go directly to the company, but instead goes

[70] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 509 (3rd ed., South Western Cengage Learning 2010).

to compensate the underwriter for its services. In fact, federal law requires that the underwriter's compensation be disclosed on the front page of the prospectus.[71] Thus, investors have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price. As a result, there is no need for PGS' shareholders to receive additional compensation to account for costs they have already considered and agreed to. We see similar compensation structures in other kinds of business transactions. For example, a homeowner may hire a realtor and sell a home for $100,000. After the realtor takes a six percent commission, the seller nets $94,000. The buyer and seller agreed to the transaction notwithstanding the realtor's commission. Obviously, it would be unreasonable for the buyer or seller to demand additional funds from anyone after the deal is completed to reimburse them for the realtor's fees. Likewise, investors of competitive firms do not expect additional compensation for flotation costs. Thus, it would not be appropriate for a commission standing in the place of competition to award a utility's investors with this additional compensation.

3. <u>It is inappropriate to add any additional basis points to an awarded ROE proposal that is already far above the Company's cost of equity.</u>

For the reasons discussed above, flotation costs should be disallowed from a technical standpoint; they should also be disallowed from a practical standpoint. PGS is asking this Commission to award it a cost of equity that is more than 300 basis points above its market-based cost of equity. Under these circumstances, it is especially inappropriate

[71] *See* Regulation S-K, 17 C.F.R. § 229.501(b)(3) (requiring that the underwriter's discounts and commissions be disclosed on the outside cover page of the prospectus). A prospectus is a legal document that provides details about an investment offering.

to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. DESCRIBE THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[72] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in Exhibit DJG 25, Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[73] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding *risks*."[74] The CAPM is a useful model because it directly considers the amount of risk inherent in a business and directly measures the most important component of a fair rate of return analysis: Risk.

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[72] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

[73] *Wilcox*, 212 U.S. at 48 (emphasis added).

[74] *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

Q. DESCRIBE THE INPUTS FOR THE CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. The Risk-Free Rate

Q. EXPLAIN THE RISK-FREE RATE.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. IS IT PREFERABLE TO USE THE YIELD ON LONG-TERM TREASURY BONDS FOR THE RISK-FREE RATE IN THE CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 1.41%.[75]

B. The Beta Coefficient

Q. HOW IS THE BETA COEFFICIENT USED IN THIS MODEL?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (less) than one is more (less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%.

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[75] Exhibit DJG-7.

Q. DESCRIBE THE SOURCE FOR THE BETAS YOU USED IN YOUR CAPM ANALYSIS.

A. I used betas recently published by Value Line Investment Survey. The beta for each proxy company is less than 1.0, and the average beta for the proxy group is only 0.85.[76] Thus, we have an objective measure to prove the well-known concept that utility stocks are less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the interest of reasonableness.[77]

C. The Equity Risk Premium

Q. DESCRIBE THE EQUITY RISK PREMIUM.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts agree that "the single most important variable for making investment decisions is the equity risk premium."[78] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average;

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[76] Exhibit DJG-8.

[77] *See* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

[78] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

(2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. HISTORICAL AVERAGE

Q. DESCRIBE THE HISTORICAL EQUITY RISK PREMIUM.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. WHAT ARE THE LIMITATIONS OF RELYING SOLELY ON A HISTORICAL AVERAGE TO ESTIMATE THE CURRENT OR FORWARD-LOOKING ERP?

A. As I mentioned, many investors use the historic ERP because it is convenient and easy to calculate. What matters in the CAPM model, however, is not the actual risk premium from the past, but rather the current and forward-looking risk premium.[79] Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[80] This is due

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[79] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

[80] Elroy Dimson, Paul Marsh & Mike Staunton, Triumph of the Optimists: 101 Years of Global Investment Returns 194 (Princeton University Press 2002).

in large part to what is known as "survivorship bias" or "success bias" — a tendency for failed companies to be excluded from historical indices.[81] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[82]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[83]

Regardless of the variations in historic ERP estimates, many leading scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[84]

Q. DID YOU RELY ON THE HISTORICAL ERP AS PART OF YOUR CAPM ANALYSIS IN THIS CASE?

A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert surveys and the implied ERP method discussed below.

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[81] *Id.* at 34.

[82] *Id.* at 194.

[83] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

[84] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

2. Expert Surveys

Q. DESCRIBE THE EXPERT SURVEY APPROACH TO ESTIMATING THE ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers and other executives around the country and asking them what they think the ERP is. Graham and Harvey have performed such a survey since 1996. In their 2018 survey, they found that experts around the country believe the current ERP is only 4.4%.[85] The IESE Business School conducts a similar expert survey. Their 2020 expert survey reported an average ERP of 5.6%.[86]

3. Implied Equity Risk Premium

Q. DESCRIBE THE IMPLIED EQUITY RISK PREMIUM APPROACH.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[87] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: The current value of an asset is equal to the present value of its future

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[85] John R. Graham and Campbell R. Harvey, *The Equity Risk Premium in 2018*, at 3 (Fuqua School of Business, Duke University 2014), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162.

[86] Pablo Fernandez, Pablo Linares & Isabel F. Acin, *Market Risk Premium used in 59 Countries in 2018: A Survey*, at 3 (IESE Business School 2018), copy available at http://www.valumonics.com/wp-content/uploads/2017/06/Discount-rate-Pablo-Fern%C3%A1ndez.pdf. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[87] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-10 (Management Science Vol. 3, No. 1 Oct. 1956).

cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: The implied market return.[88]

Equation 2:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

[88] *See* Exhibit DJG-9 for detailed calculation.

where: V_{500} = *current value of index (S&P 500)*
CY_{1-5} = *average cash yield over last five years (includes dividends and buybacks)*
g = *compound growth rate in earnings over last five years*
R_F = *risk-free rate*
K = *implied market return (this is what we are solving for)*
TV = *terminal value* $= CY_5(1+R_F)/K$

The discount rate is called the "implied" return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP.

Equation 3:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. DISCUSS THE RESULTS OF YOUR IMPLIED ERP CALCULATION.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.21%.[89] I subtracted the risk-free rate to arrive at the implied equity risk premium of 5.8%.[90] Dr.

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[89] *Id.*

[90] *Id.*

Damodaran, arguably one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. Using variations of this method, he calculates and publishes his ERP results each month. Dr. Damodaran's *highest* ERP estimate for July 2020 using several implied ERP variations was only 5.68%.[91]

Q. WHAT ARE THE RESULTS OF YOUR FINAL ERP ESTIMATE?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys, the implied ERP calculations discussed above, and the estimated ERP reported by Duff & Phelps.[92] The results are presented in the following figure:

Figure 11:
Equity Risk Premium Results

IESE Business School Survey	5.6%
Graham & Harvey Survey	4.4%
Duff & Phelps Report	6.0%
Damodaran	5.7%
Garrett	5.8%
Average	**5.5%**
Highest	**6.0%**

While it would be reasonable to select any one of these ERP estimates to use in the CAPM, I conservatively selected the *highest* ERP estimate of 6.0% to use in my CAPM analysis.

[91] http://pages.stern.nyu.edu/~adamodar/

[92] *See also* Exhibit DJG-10.

All else held constant, a higher ERP used in the CAPM will result in a higher cost of equity estimate.

Q. PLEASE EXPLAIN THE FINAL RESULTS OF YOUR CAPM ANALYSIS.

A. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, I estimate that the Company's CAPM cost of equity is 6.5%.[93] The CAPM can be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

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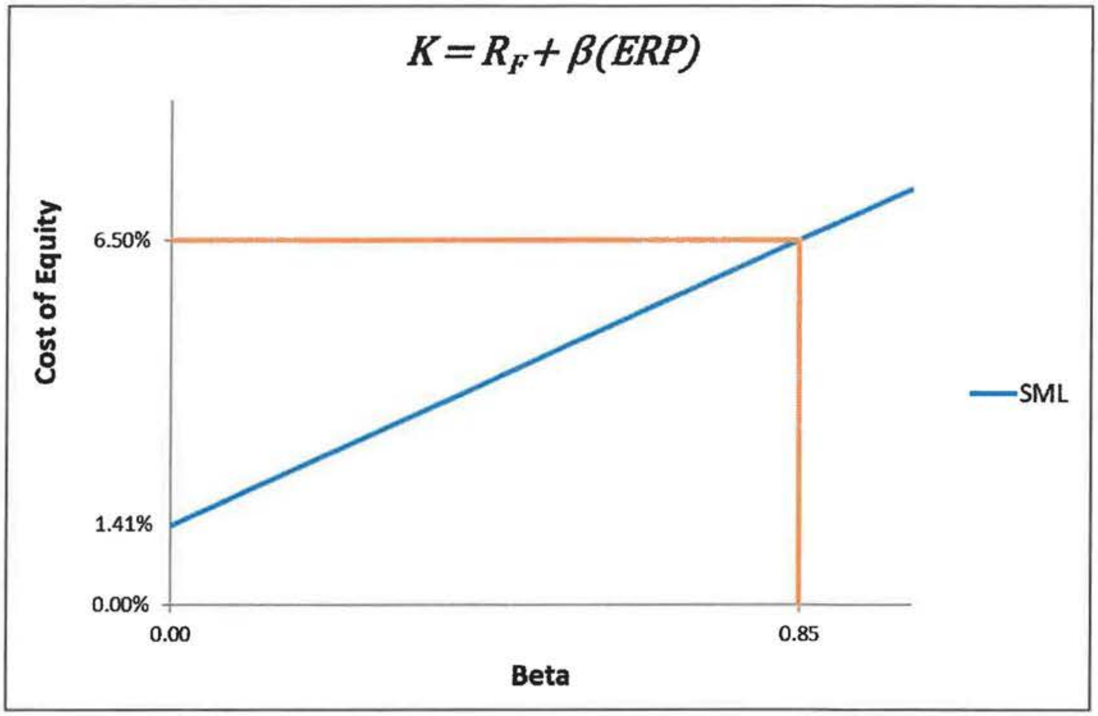
[93] Exhibit DJG-11.

Figure 12:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.85 for the proxy group, the estimated CAPM cost of equity for the Company is 6.5%.

D. Response to Mr. Hevert's CAPM Analysis and Other Issues

Q. MR. HEVERT'S CAPM ANALYSIS YIELDS CONSIDERABLY HIGHER RESULTS. DID YOU FIND SPECIFIC PROBLEMS WITH MR. HEVERT'S CAPM ASSUMPTIONS AND INPUTS?

A. Yes. The results of Mr. Hevert's various CAPMs are as high as 14%,[94] which is considerably higher than my estimate. The main problem with Mr. Hevert's CAPM cost of equity result stems primarily from his estimate of the equity risk premium ("ERP").

1. Equity Risk Premium

Q. DID MR. HEVERT RELY ON A REASONABLE MEASURE FOR THE ERP?

A. No, he did not. Mr. Hevert estimates an ERP as high as 13%.[95] The ERP is one of three inputs in the CAPM equation, and it is one of the most single important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The highest ERP found from my research and analysis is only 6.0%.[96] This means that Mr. Hevert's ERP estimate is more than twice as high as the highest reasonable ERP I could either find or calculate. And, as noted, it is also considerably higher than that of reputable analysts.

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[94] Exhibit No. (RBH-1), Document No. 6.

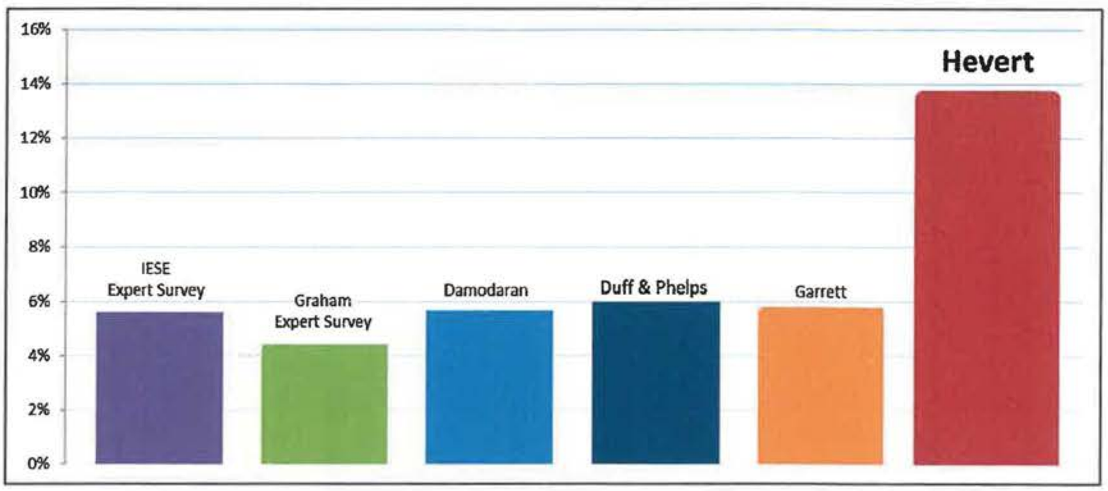
[95] *Id.*

[96] Exhibit DJG-10.

Q. PLEASE DISCUSS AND ILLUSTRATE HOW MR. HEVERT'S ERP COMPARES WITH OTHER ESTIMATES FOR THE ERP.

A. As discussed above, Graham and Harvey's 2018 expert survey reports an average ERP of 4.4%. The 2020 IESE Business School expert survey reports an average ERP of 5.6%. Similarly, Duff & Phelps recently estimated an ERP of 6.0%. The following chart illustrates that Mr. Hevert's ERP estimate is far out of line with industry norms.[97]

Figure 13:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), which do not have a wide variance, Mr. Hevert's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated and unreliable.

[97] *See* Exhibit DJG-10. The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under varying assumptions.

2. Other Risk Premium Analyses

Q. DID YOU REVIEW MR. HEVERT'S OTHER RISK PREMIUM ANALYSES?

A. Yes. I am addressing Mr. Hevert's other risk premium analyses in this section because the CAPM itself is a risk premium model. In this case, Mr. Hevert conducted what he calls a "bond yield plus risk premium" analysis.[98] Many utility-company ROE witnesses conduct what they call a "historical risk premium analysis," "bond yield plus risk premium analysis" or "allowed return premium analysis." In short, these types of analyses simply compare the difference between awarded ROEs in the past with bond yields.

Q. DO YOU AGREE WITH THE RESULTS OF MR. HEVERT'S RISK PREMIUM ANALYSIS?

A. No. I disagree with the entire premise of the analysis. First, Mr. Hevert looked at awarded ROEs dating back to 1980 — a direct contradiction to Mr. Hevert's claim that the cost of equity is a "forward-looking" concept.[99] As discussed earlier in this testimony, it is clear that awarded ROEs are consistently higher than market-based cost of equity, and they have been for many years. Thus, these types of risk premium "models" are merely clever devices used to perpetuate the discrepancy between awarded ROEs and market-based cost of equity. In other words, since awarded ROEs are consistently higher than market-based cost, a model that simply compares the discrepancy between awarded ROEs and any market-based factor (such as bond yields) will simply ensure that the discrepancy

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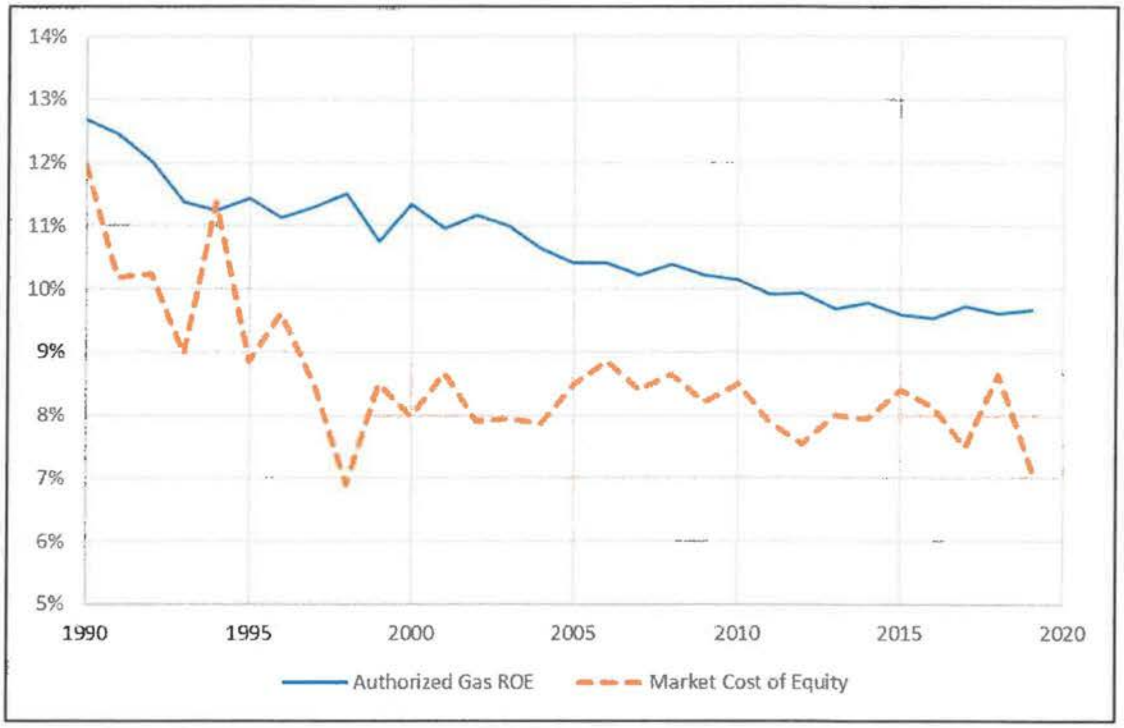
[98] Direct Testimony of Robert B. Hevert, p. 78.

[99] *See e.g.*, Direct Testimony of Robert B. Hevert, p. 68, lines 22-23.

continues. The following graph shows the clear disconnect between awarded ROEs and utility cost of equity.[100]



Since it is indisputable that utility stocks are *less risky* than average stock in the market (with a beta equal to 1.0), utility cost of equity is *below* the market cost of equity (the dotted line in the graph above). The gap between the market cost of equity and inflated ROEs represents an excess transfer of wealth from customers to shareholders.

Furthermore, the risk premium analysis offered by Mr. Hevert is completely unnecessary when we already have a real risk premium model to use: the CAPM. The CAPM itself is a "risk premium" model; it takes the bare minimum return any investor would require for buying a stock (the risk-free rate), then adds a *premium* to compensate

[100] *See also* Exhibit DJG-14.

the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security. The CAPM has been utilized by companies around the world for decades for the same purpose we are using it in this case — to estimate cost of equity.

In stark contrast to the Nobel-prize-winning CAPM, the risk premium models relied upon by utility ROE witnesses are not market-based, and therefore have no value in helping us estimate the market-based cost of equity. Unlike the CAPM, which is found in almost every comprehensive financial textbook, the risk premium models used by utility witnesses are almost exclusively found in the texts and testimonies of such witnesses. Specifically, these risk premium models attempt to create an inappropriate link between market-based factors, such as interest rates, with awarded returns on equity. Inevitably, this type of model is used to justify a cost of equity that is much higher than one that would be dictated by market forces.

VIII. COST OF EQUITY SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF THE CAPM AND DCF MODEL DISCUSSED ABOVE.

A. The following table shows the cost of equity results from each model I employed in this case.[101]

[101] *See* Exhibit DJG-12.

Figure 14:
Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	7.3%
Capital Asset Pricing Model	6.5%
Average	**6.9%**

The cost of equity indicated by the results of the DCF Model and the CAPM is approximately 6.9%.

Q. IS THERE A MARKET INDICATOR THAT YOU CAN USE TO TEST THE REASONABLENESS OF YOUR COST OF EQUITY ESTIMATE?

A. Yes, there is. The CAPM is a risk premium model based on the fact that all investors will require, at a minimum, a return equal to the risk-free rate when investing in equity securities. Of course, the investors will also require a premium on top of the risk-free rate to compensate them for the risk they have assumed. If an investor bought every stock in the market portfolio, he would require the risk-free rate, plus the ERP discussed above. Recall that the risk-free rate plus the ERP is called the required return on the market portfolio. This could also be called the market cost of equity. It is undisputed that the cost of equity of utility stocks must be less than the total market cost of equity. This is because utility stocks are less risky than the average stock in the market. (We proved this above by showing that utility betas were less than one). Therefore, once we determine the market cost of equity, it gives us a "ceiling" below which the Company's actual cost of equity must lie.

Q. DESCRIBE HOW YOU ESTIMATED THE MARKET COST OF EQUITY.

A. The methods used to estimate the market cost of equity are necessarily related to the methods used to estimate the ERP discussed above. In fact, the ERP is calculated by taking the market cost of equity less the risk-free rate. Therefore, in estimating the market cost of equity, I relied on the same methods discussed above to estimate the ERP: (1) consulting expert surveys; and (2) calculating the implied ERP. The results of my market cost of equity analysis are presented in the following table:[102]

Figure 15:
Market Cost of Equity Summary

Source	Estimate
IESE Survey	7.0%
Graham Harvey Survey	5.8%
Duff & Phelps	7.4%
Damodaran	7.1%
Garrett	7.2%
Highest	7.4%

As shown in this table, the average market cost of equity from these sources is only 7.4%. Therefore, it is not surprising that the CAPM and DCF Model indicate a cost of equity for the Company of only 6.9%. In other words, any cost of equity estimates for the Company

[102] *See* Exhibit DJG-13.

(or any regulated utility) that is *above* the market cost of equity should be viewed as unreasonable (again, the cost of equity is a different concept that the awarded ROE).

IX. CONCLUSION AND RECOMMENDATION — COST OF CAPITAL

Q. SUMMARIZE THE KEY POINTS OF YOUR COST OF CAPITAL TESTIMONY.

A. The awarded ROE in this case should be based on PGS's cost of equity. Closely estimating the cost of equity with the CAPM and other models is a relatively straightforward process that has been used in the competitive marketplace for many decades. While regulators determine the awarded return for utilities, they do not determine the cost of capital, which is primarily driven by the equity risk premium and other market forces. Any objective estimation of PGS's cost of equity would result in one that is remarkably less than the awarded ROEs that are generally given to utility shareholders. While there may be policy reasons as to why the awarded return should be set higher than the cost of equity, we must be intellectually honest about where the cost of equity for a very low-risk company such as PGS actually is. Using reasonable and conservative inputs, the CAPM and DCF Model indicate that PGS's cost of equity is about 6.9%. This strongly indicates that the Company's proposed ROE of 10.75% is excessive and unreasonable.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION REGARDING PGS'S COST OF CAPITAL.

A. I recommend the Commission award the Company with a 9.5% ROE. Although PGS's cost of equity is clearly much lower than 9.5% by any objective measure, the Commission should gradually reduce PGS's awarded return towards market-based levels, consistent with the *Hope* Court's end result doctrine.

Q. DOES THIS CONCLUDE THE COST OF CAPITAL PORTION OF YOUR TESTIMONY?

A. Yes. The following sections of my testimony are related to depreciation.

PART TWO: DEPRECIATION

X. LEGAL STANDARDS

Q. DISCUSS THE STANDARD BY WHICH REGULATED UTILITIES ARE ALLOWED TO RECOVER DEPRECIATION EXPENSE.

A. In *Lindheimer v. Illinois Bell Telephone Co.*,[103] the U.S. Supreme Court stated that "depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence." The *Lindheimer* Court also recognized that the original cost of plant assets, rather than present value or some other measure, is the proper basis for calculating depreciation expense.[104] Moreover, the *Lindheimer* Court found:

> [T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.[105]

Thus, the Commission must ultimately determine if the Company has met its burden of proof by making a convincing showing that its proposed depreciation rates are not excessive.

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[103] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).

[104] *Id.* (Referring to the straight-line method, the *Lindheimer* Court stated that "[a]ccording to the principle of this accounting practice, the loss is computed upon the actual cost of the property as entered upon the books, less the expected salvage, and the amount charged each year is one year's pro rata share of the total amount."). The original cost standard was reaffirmed by the Court in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944). The *Hope* Court stated: "Moreover, this Court recognized in [*Lindheimer*], supra, the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required."

[105] *Id.* at 169.

Q. SHOULD DEPRECIATION REPRESENT AN ALLOCATED COST OF CAPITAL TO OPERATION, RATHER THAN A MECHANISM TO DETERMINE LOSS OF VALUE?

A. Yes. While the *Lindheimer* case and other early literature recognized depreciation as a necessary expense, the language indicated that depreciation was primarily a mechanism to determine loss of value.[106] Adoption of this "value concept" would require annual appraisals of extensive utility plant, and thus, is not practical in this context. Rather, the "cost allocation concept" recognizes that depreciation is a cost of providing service, and that in addition to receiving a "return on" invested capital through the allowed rate of return, a utility should also receive a "return of" its invested capital in the form of recovered depreciation expense. The cost allocation concept also satisfies several fundamental accounting principles, including verifiability, neutrality, and the matching principle.[107] The definition of "depreciation accounting" published by the American Institute of Certified Public Accountants ("AICPA") properly reflects the cost allocation concept:

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[106] *See* Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 71 (Iowa State University Press 1994).

[107] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 12 (NARUC 1996).

> Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.[108]

Thus, the concept of depreciation as "the allocation of cost has proven to be the most useful and most widely used concept."[109]

XI. ANALYTIC METHODS

Q. DISCUSS YOUR APPROACH TO ANALYZING THE COMPANY'S DEPRECIABLE PROPERTY IN THIS CASE.

A. I obtained and reviewed all of the data that was used to conduct the Company's depreciation study. I used the same plant data in my analysis to develop my proposed depreciation rates and applied those rates to the Company's updated plant balances to arrive at OPC's final adjustment to depreciation expense.[110]

Q. DISCUSS THE DEFINITION AND PURPOSE OF A DEPRECIATION SYSTEM, AS WELL AS THE DEPRECIATION SYSTEM YOU EMPLOYED FOR THIS PROJECT.

A. The legal standards set forth above do not mandate a specific procedure for conducting a depreciation analysis. These standards, however, direct that analysts use a system for estimating depreciation rates that will result in the "systematic and rational" allocation of

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[108] American Institute of Accountants, *Accounting Terminology Bulletins Number 1: Review and Résumé* 25 (American Institute of Accountants 1953).

[109] Wolf *supra* n. 105, at 73.

[110] *See* Exhibit DJG-15.

capital recovery for the utility. Over the years, analysts have developed "depreciation systems" designed to analyze grouped property in accordance with this standard. A depreciation system may be defined by several primary parameters: 1) a *method* of allocation; 2) a *procedure* for applying the method of allocation; 3) a *technique* of applying the depreciation rate; and 4) a *model* for analyzing the characteristics of vintage property groups.[111] In this case, I used the straight line method, the average life procedure, the remaining life technique, and the broad group model to analyze the Company's actuarial data; this system would be denoted as an "SL-AL-RL-BG" system. This depreciation system conforms to the legal standards set forth above, and is commonly used by depreciation analysts in regulatory proceedings. I provide a more detailed discussion of depreciation system parameters, theories, and equations in Exhibit DJG 25, Appendix C.

Q. ARE THERE OTHER REASONABLE DEPRECIATION SYSTEMS THAT ANALYSTS MAY USE?

A. Yes. There are multiple combinations of depreciation systems that analysts may use to develop deprecation rates. For example, many analysts use the broad group model instead of the equal life group model. In this case, however, I used the same depreciation system that Company Witness Watson used. Although some of our assumptions and inputs are different, the analytical system we applied is essentially the same.

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[111] *See* Wolf *supra* n. 105, at 70, 140.

XII. ACTUARIAL ANALYSIS

Q. DESCRIBE THE ACTUARIAL PROCESS YOU USED TO ANALYZE THE COMPANY'S DEPRECIABLE PROPERTY.

A. The study of retirement patterns of industrial property is derived from the actuarial process used to study human mortality. Just as actuarial analysts study historical human mortality data in order to predict how long a group of people will live, depreciation analysts study historical plant data in order to estimate the average lives of property groups. The most common actuarial method used by depreciation analysts is called the "retirement rate method." In the retirement rate method, original property data, including additions, retirements, transfers, and other transactions, are organized by vintage and transaction year.[112] The retirement rate method is ultimately used to develop an "observed life table," ("OLT") which shows the percentage of property surviving at each age interval. This pattern of property retirement is described as a "survivor curve." The survivor curve derived from the observed life table, however, must be fitted and smoothed with a complete curve in order to determine the ultimate average life of the group.[113] The most widely used survivor curves for this curve fitting process were developed at Iowa State University in the early 1900s and are commonly known as the "Iowa curves."[114] A more detailed explanation of how the Iowa curves are used in the actuarial analysis of depreciable

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[112] The "vintage" year refers to the year that a group of property was placed in service (aka "placement" year). The "transaction" year refers to the accounting year in which a property transaction occurred, such as an addition, retirement, or transfer (aka "experience" year).

[113] *See* Exhibit DJG 25, Appendix E for a more detailed discussion of the actuarial analysis used to determine the average lives of grouped industrial property.

[114] *See* Exhibit DJG 25, Appendix D for a more detailed discussion of the Iowa curves.

property is set forth in Exhibit DJG 25, Appendix E. For a few of PGS's accounts, there were sufficient aged data to conduct actuarial analysis and traditional Iowa curve fitting techniques. Regardless of whether a particular account had sufficient aged data, I began my analysis of each account by organizing the data to develop observed life tables, which is discussed further below.

Q. GENERALLY DESCRIBE YOUR APPROACH IN ESTIMATING THE SERVICE LIVES OF MASS PROPERTY.

A. I used all of the Company's aged property data to create an OLT for each account. The data points on the OLT can be plotted to form a curve (the "OLT curve"). The OLT curve is not a theoretical curve, rather, it is actual observed data from the Company's records that indicate the rate of retirement for each property group. An OLT curve by itself, however, is rarely a smooth curve, and is often not a "complete" curve (i.e., it does not end at zero percent surviving). In order to calculate average life (the area under a curve), a complete survivor curve is needed. The Iowa curves are empirically-derived curves based on the extensive studies of the actual mortality patterns of many different types of industrial property. The curve-fitting process involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. The first step of my approach to curve-fitting involves visually inspecting the OLT curve for any irregularities. For example, if the "tail" end of the curve is erratic and shows a sharp decline over a short period of time, it may indicate that this portion of the data is less reliable, as further discussed below. After inspecting the OLT curve, I use a mathematical curve-fitting technique which essentially involves measuring the distance between the OLT curve and the selected Iowa curve in order to get an objective, mathematical assessment of how well the curve fits. After selecting an Iowa curve, I observe the OLT curve along with the Iowa curve on the same graph to determine how well the curve fits. I may repeat this process several times for any given account to ensure that the most reasonable Iowa curve is selected.

Q. DO YOU ALWAYS SELECT THE MATHEMATICALLY BEST-FITTING CURVE?

A. Not necessarily. Mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results. While mathematical curve fitting is important, however, it may not always yield the optimum result; therefore, it should not necessarily be adopted without further analysis.

Q. SHOULD EVERY PORTION OF THE OLT CURVE BE GIVEN EQUAL WEIGHT?

A. Not necessarily. Many analysts have observed that the points comprising the "tail end" of the OLT curve may often have less analytical value than other portions of the curve. In fact, "[p]oints at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures."[115] In accordance with this standard, an analyst may decide to truncate the tail end of the OLT curve at a certain percent of initial exposures, such as one percent. Using this approach puts a greater emphasis on the most valuable portions of the curve. For my analysis in this case, I not only considered the entirety of the OLT curve, but I also conducted further analyses that involved fitting Iowa curves to the

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[115] Wolf *supra* n. 105, at 46.

most significant part of the OLT curve for certain accounts. In other words, to verify the accuracy of my curve selection, I narrowed the focus of my additional calculation to consider the top 99% of the "exposures" (i.e., dollars exposed to retirement) and to eliminate the tail end of the curve representing the bottom 1% of exposures. I will illustrate an example of this approach in the discussion below.

Q. GENERALLY, DESCRIBE THE DIFFERENCES BETWEEN THE COMPANY'S SERVICE LIFE PROPOSALS AND YOUR SERVICE LIFE PROPOSALS.

A. For each of these accounts discussed below, the Company's proposed service life, as estimated through Iowa curves, is too short to accurately describe the mortality characteristics of the account in my opinion. For the accounts in which I propose a longer service life, I took the objective approach and chose an Iowa curve that provides a better mathematical and/or visual fit to the observed historical retirement pattern derived from the Company's plant data.

Q. HAS THE COMPANY MADE A CONVINCING SHOWING THAT THE PROPOSED SERVICE LIFE ESTIMATES FOR THE FOLLOWING ACCOUNTS ARE NOT EXCESSIVE?

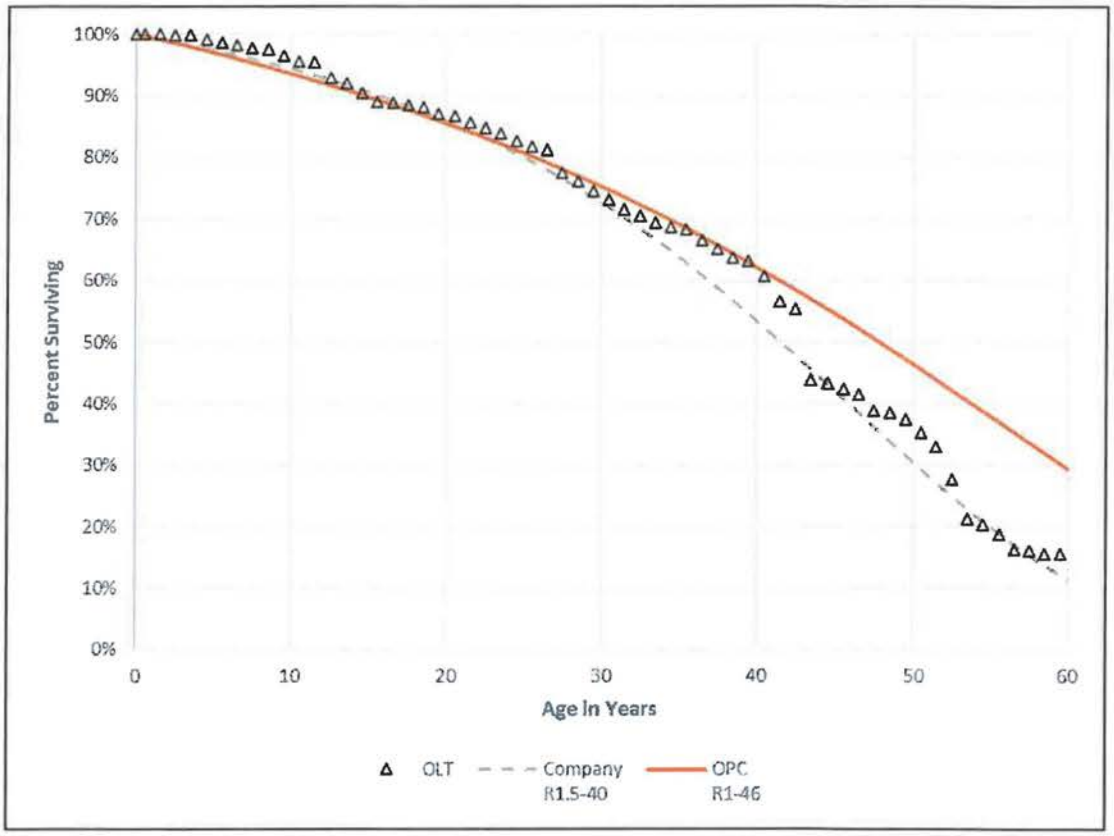
A. No, not in my opinion. As stated in the legal standards discussed above, the Company has the burden to make a convincing showing that its proposed depreciation rates are not excessive. Necessarily, this standard must include making convincing showings that service life and net salvage estimates are not excessive. Both Mr. Watson and I are primarily relying upon the historical, statistical retirement data observed in the Company's continuing property records to conduct our analysis. In making my recommended service life estimates, I use a combination of visual and mathematical curve fitting along with professional judgment. Unless the Company presents a convincing reason to deviate from the historical service retirement patterns observed in its accounts when projecting future remaining life, it is my opinion that the best service life estimates as indicated by mathematical curve fitting should be given primary consideration. For the accounts discussed below, the Company has failed to make a convincing showing that its service life estimates are not excessively short (i.e., shorter service life estimates result in higher depreciation rates).

A. Account 368 – Measuring and Regulating Station Equipment

Q. DESCRIBE YOUR SERVICE LIFE ESTIMATE FOR ACCOUNT 368 AND COMPARE IT WITH THE COMPANY'S ESTIMATE.

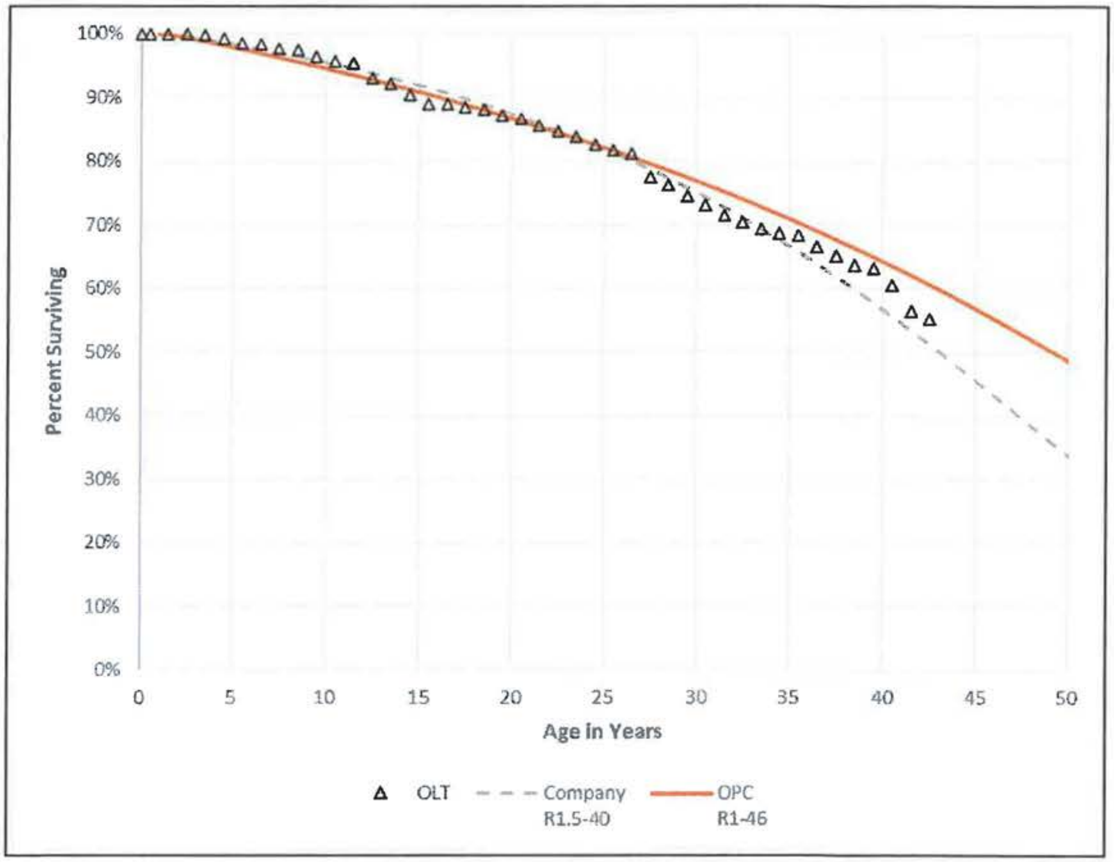
A. The OLT curve for this account is shown in the graph below. The graph also shows the Iowa curves that Mr. Watson and I selected to estimate the average life for this account. The average life is determined by calculating the area under the Iowa curves. Thus, a longer curve will produce a longer average life, and it will also result in a lower depreciation rate. For this account, Mr. Watson selected the R1.5-40 Iowa curve, and I selected the R1-46 Iowa curve. The average lives resulting from each curve are indicated by the numbers after the dashes (40 and 46 in this case). Both Iowa curves are shown with the OLT curve in the graph below.

Figure 16:
Account 368 – Measuring and Regulating Station Equipment



From a visual perspective, it appears that both of the selected Iowa curves provide good fits to data points on the OLT curve through the first 30 years. After that point, it initially appears that the R1.5-40 curve selected by Mr. Watson provides a closer fit. However, the data points occurring after the 40-year age interval are not statistically relevant pursuant to the 1% cutoff benchmark discussed above. This is because the dollars exposed to retirement for these data points at the tail end of this OLT curve are relatively insignificant. For example, the dollars exposed to retirement at 60 years is only $13,000, whereas the initial dollars exposed to retirement (at age zero), is $20 million. Notice on the OLT curve there is a sharp drop in the curve around age 43. The data points occurring after this drop off are relatively insignificant. The following graph shows the same OLT curve and Iowa graph, except with only the most significant portions of the OLT curve showing.

Figure 17:
Account 368 – With Relevant OLT Curve



Considering the relevant OLT curve, both Iowa curves appear to provide relatively good fits. We can use mathematical curve fitting to measure which Iowa curve provides the closer fit.

Q. DOES THE IOWA CURVE YOU SELECTED PROVIDE A BETTER MATHEMATICAL FIT TO THE RELEVANT OLT CURVE FOR THIS ACCOUNT?

A. Yes. While visual curve-fitting techniques helped us to identify the most statistically relevant portions of the OLT curve for this account, mathematical curve-fitting techniques can help us determine which of the two Iowa curves provides the better fit. Mathematical curve fitting essentially involves measuring the distance between the OLT curve and the selected Iowa curve. The best mathematically-fitted curve is the one that minimizes the distance between the OLT curve and the Iowa curve, thus providing the closest fit. The "distance" between the curves is calculated using the "sum-of-squared differences" ("SSD") technique. For this account, the SSD, or "distance" between the OLT curve and the Company's R1.5-40 Iowa curve is 0.0475, while the SSD between the OLT curve and the R1-46 Iowa curve I selected is only 0.0119.[116] Thus, the R1-46 curve results in a closer mathematical fit.

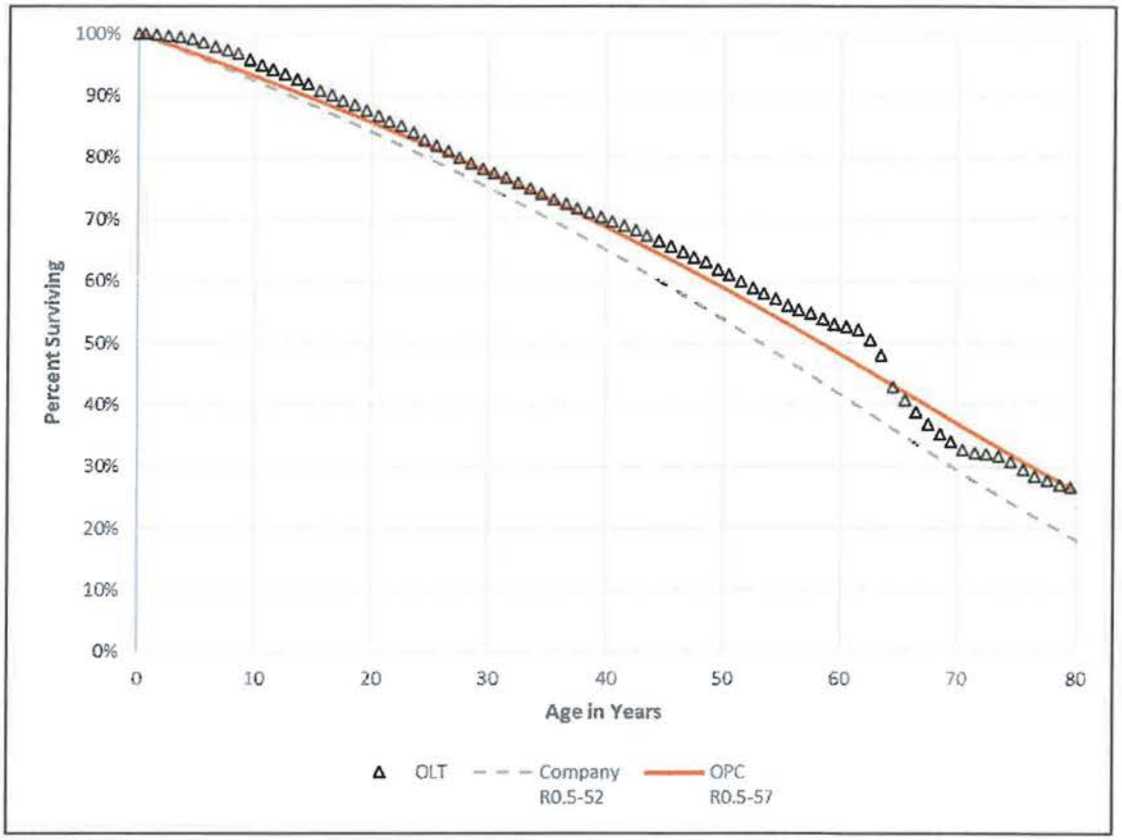
B. Account 380 – Services – Steel

Q. DESCRIBE YOUR SERVICE LIFE ESTIMATE FOR THIS ACCOUNT AND COMPARE IT WITH THE COMPANY'S ESTIMATE.

A. For this account, Mr. Watson selected the R0.5-42 curve, and I selected the R0.5-57 curve. Thus, both Iowa curves have the same "shape," but the Iowa curve I selected has a longer average life. Both Iowa curves are shown with the OLT curve in the graph below.

[116] Exhibit DJG-19.

Figure 18:
Account 380 – Services – Steel



From a visual perspective, it is clear that the R0.5-57 curve provides a better fit throughout the OLT curve. Specifically, the R0.5-52 curve selected by Mr. Watson is too short to provide an accurate fit to the OLT curve. As a result, his depreciation rate for this account is overstated.

Q. DOES THE IOWA CURVE YOU SELECTED PROVIDE A BETTER MATHEMATICAL FIT TO THE OLT CURVE FOR THIS ACCOUNT?

A. Yes. Although it is visually clear that the R0.5-57 curve provides the better fit, we can confirm the results mathematically. Specifically, the total SSD for the Company's curve is 0.3169, while the SSD for the R0.5-57 curve is only 0.0556, which means it provides the closer fit.[117]

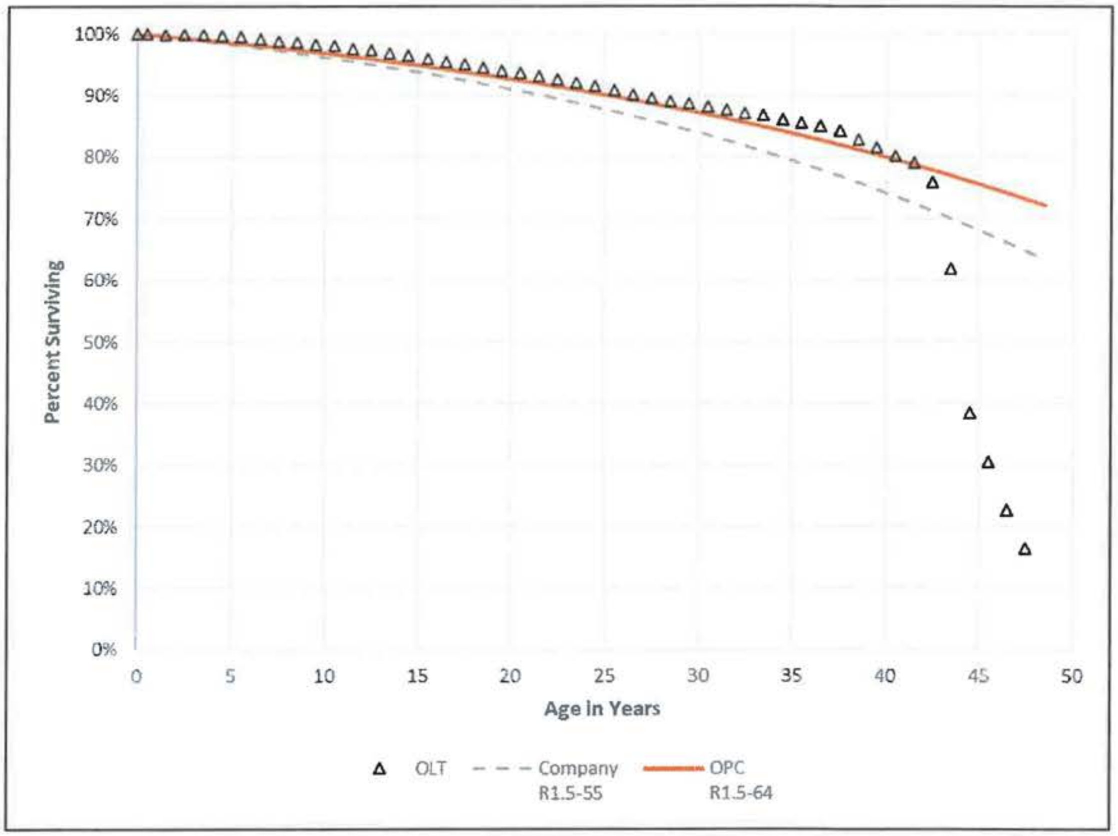
C. Account 380.02 – Services – Plastic

Q. DESCRIBE YOUR SERVICE LIFE ESTIMATE FOR THIS ACCOUNT AND COMPARE IT WITH THE COMPANY'S ESTIMATE.

A. For this account, Mr. Watson selected the R1.5-55 curve, and I selected the R1.5-64 curve. Both Iowa curves are shown with the OLT curve in the graph below.

[117] Exhibit DJG-20.

Figure 19:
Account 380.02 – Services – Plastic



As shown in this graph, both Iowa curves properly ignore the tail end of this OLT curve — where the OLT data points begin to drastically decline. Regardless, a visual inspection reveals that the R1.5-64 curve provides a closer fit. We can nonetheless confirm the results mathematically.

Q. DOES THE IOWA CURVE YOU SELECTED PROVIDE A BETTER MATHEMATICAL FIT TO THE OLT CURVE FOR THIS ACCOUNT?

A. Yes. Specifically, the total SSD for the Company's curve is 0.0490, while the SSD for the R1.5-64 curve I selected is only 0.0065, which means it provides the closer fit.[118]

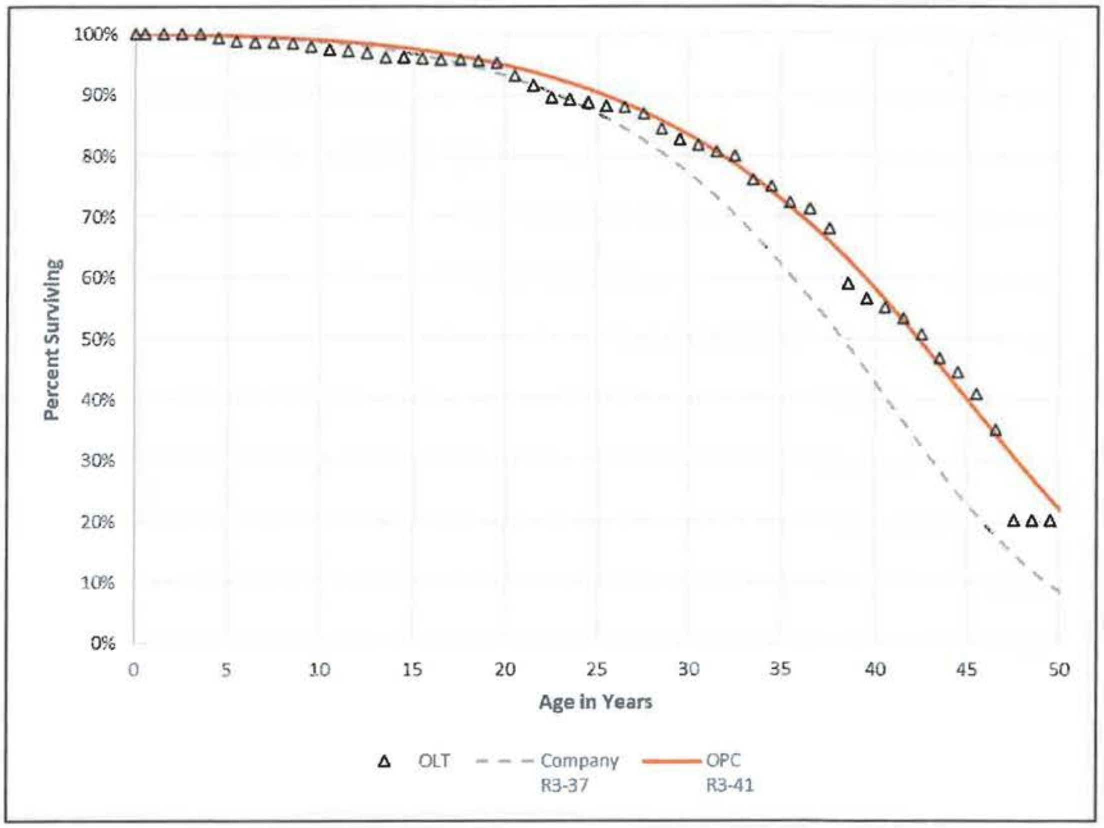
D. Account 385 – Industrial Measuring and Regulating Station Equipment

Q. DESCRIBE YOUR SERVICE LIFE ESTIMATE FOR THIS ACCOUNT AND COMPARE IT WITH THE COMPANY'S ESTIMATE.

A. For this account, Mr. Watson selected the R3-37 curve, and I selected the R3-41 curve. Both Iowa curves are shown with the OLT curve in the graph below.

[118] Exhibit DJG-21.

Figure 20:
Account 385 – Industrial Measuring and Regulating Station Equipment



As with the other accounts discussed above, even from a visual perspective it is clear that the Iowa curve I selected provides a better fit to the observed data. The fact that the Iowa curve I selected provides a better fit to the historical data is a strong indication that the remaining life calculated from the Iowa curve I selected is more accurate and reasonable than that proposed by the Company.

Q. DOES THE IOWA CURVE YOU SELECTED PROVIDE A BETTER MATHEMATICAL FIT TO THE OLT CURVE FOR THIS ACCOUNT?

A. Yes. The total SSD for the Company's curve is 0.3842, while the SSD for the R3-41 curve I selected is only 0.0288, which means it provides the closer fit.[119]

XIII. NET SALVAGE ANALYSIS

Q. DESCRIBE THE CONCEPT OF NET SALVAGE.

A. If an asset has any value left when it is retired from service, a utility might decide to sell the asset. The proceeds from this transaction are called "gross salvage." The corresponding expense associated with the removal of the asset from service is called the "cost of removal." The term "net salvage" equates to gross salvage less the cost of removal. Often, the net salvage for utility assets is a negative number (or percentage) because the cost of removing the assets from service exceeds any proceeds received from selling the assets. When a negative net salvage rate is applied to an account to calculate the depreciation rate, it results in increasing the total depreciable base to be recovered over a particular period of time and increases the depreciation rate. Therefore, a greater *negative* net salvage rate equates to a higher depreciation rate and expense, all else held constant.

Q. HAS THERE BEEN A TREND IN INCREASING NEGATIVE NET SALVAGE IN THE UTILITY INDUSTRY?

A. Yes. As discussed above, negative net salvage rates occur when the cost of removal exceeds the gross salvage of an asset when it is removed from service. Net salvage rates

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[119] Exhibit DJG-22.

are calculated by considering gross salvage and removal costs as a percent of the original cost of the assets retired. In other words, salvage and removal costs are based on current dollars (when the assets are removed from service), while retirements are based on historical dollars, reflecting uninflated cost figures from years, and often decades earlier. Increasing labor costs associated with asset removal combined with the fact that original costs remain the same have contributed to increasing negative net salvage over time.

Q. PLEASE SUMMARIZE MR. WATSON'S PROPOSED NET SALVAGE RATES.

A. Mr. Watson is proposing significant net salvage decreases for several of the Company's distribution accounts. He is not proposing net salvage increases for any of the Company's distribution accounts.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED NET SALVAGE RATES?

A. Yes. I identified six distribution accounts to which Mr. Watson is proposing substantial net salvage decreases. While I would not disagree with Mr. Watson that there should be decreases to these accounts, I am recommending that the Commission implement the changes in net salvage rates for these accounts more gradually than that proposed by the Company. Specifically, I recommend limiting the proposed net salvage decreases by one half of the decrease proposed by Mr. Watson. The accounts to which I propose net salvage adjustments are summarized in the table below.

Figure 21:
Net Salvage Adjustments

Account No.	Description	Current NS	Watson NS	Garrett NS
376.00	Mains Steel	-40%	-60%	-50%
376.02	Mains Plastic	-25%	-40%	-33%
380.00	Services Steel	-100%	-150%	-125%
380.02	Services Plastic	-55%	-80%	-68%
382.00	Meter Installations	-20%	-30%	-25%
384.00	House Regulator Installs	-20%	-30%	-25%

As shown in the table, my proposed net salvage rates are in between the current rates and the rates proposed by Mr. Watson.

Q. ARE YOU AWARE OF OTHER COMMISSIONS WHO LIMIT NET SALVAGE INCREASES AS A MATTER OF POLICY, BASED ON GRADUALISM?

A. Yes. The California Commission has expressed concerns over the phenomenon of increasing net salvage rates. In Pacific Gas & Electric's ("PG&E") 2014 general rate case, the California commission stated: "We remain concerned with the growing cost burden associated with increasing cost trends for negative net salvage."[120] The Commission also expressed an interest in the ratemaking concept of gradualism. According to the Commission:

[120] Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016, D.14-08-032, p. 597

> In evaluating whether a proposed increase reflects gradualism, however, we believe the more appropriate measure is how the change affects customers' retail rates. The fact that PG&E previously proposed higher removal costs than adopted has no bearing on how a proposed change would impact current ratepayers. Accordingly, we apply the principle of gradualism based on how a proposed change in estimate compares to adopted costs reflected in current rates, irrespective of what PG&E may have forecasted in an earlier depreciation study.[121]

In PG&E's 2014 GRC, the Office of Ratepayer Advocates proposed a 25% cap on increased net salvage rates to mitigate sudden increases in net salvage and instead provide for more gradual levels of increases. The Commission ultimately found: "As a general approach, we adopt no more than 25% of PG&E's estimated increases in the accrual provision for removal costs. This limitation tempers the impacts on current ratepayers. . . ."[122] In PGS's case, I recommend the Commission consider a similar approach regarding net salvage except with a 50% limit instead of a 25% limit.

XIV. CONCLUSION AND RECOMMENDATION — DEPRECIATION

Q. PLEASE SUMMARIZE THE KEY POINTS OF YOUR DEPRECIATION TESTIMONY.

A. I employed a well-established depreciation system and used actuarial and simulated analysis to statistically analyze the Company's depreciable assets in order to develop reasonable depreciation rates in this case. I made adjustments to the Company's proposed service life and net salvage for several accounts. Regarding service life, the Company's own historical data indicates that for several accounts, Mr. Watson has recommended

[121] *Id.* at 598.

[122] Id. at 602.

service lives that are too short, which has resulted in overestimated depreciation rate proposals. Regarding net salvage, I recommend the Commission limit the Company's proposed net salvage increases by 50% for several accounts in the interest of gradualism.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING DEPRECIATION?

A. I recommend the Commission adopt the depreciation rates and parameters presented in Exhibit DJG-16.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. I reserve the right to supplement this testimony as needed with any additional information that has been requested from the Company but not yet provided. To the extent I have not addressed an issue, method, calculation, account, or other matter relevant to the Company's proposals in this proceeding, it should not be construed that I am in agreement with the same.

(Whereupon, prefiled direct testimony of Andrea C. Crane was inserted.)

ERRATA SHEET

WITNESS: Andrea C. Crane

The following table contains the corrected errata in her direct testimony.

Page	**Line**	**Original**	**Revision**
Page 5	Line 1	$58.8	$58.3
Page 5	Line 2	Exhibit ACC-2, Schedule 7	Exhibit ACC-2, Schedule 7 Revised
Page 5	Line 4	$42.3	$42.9
Page 5	Line 5	Exhibit ACC-2, Schedule 1	Exhibit ACC-2, Schedule 1 Revised
Page 5	Line 8	$18.6	$19.3
Page 25	Line 20	Exhibit ACC-2, Schedule 10	Exhibit ACC-2, Schedule 10 Revised
Page 26	Line 7	Exhibit ACC-2, Schedule 11	Exhibit ACC-2, Schedule 11 Revised
Page 45	Line 17	42,221,562	$42,860,644
Page 45	Line 17	Exhibit ACC-2, Schedule 1	Exhibit ACC-2, Schedule 1 Revised
Page 45	Line 18	$42,103,332	42,464,250
Page 45	Line 20	17.2%	17.5%
Page 46	Line 3	$18,612,979	$19,252,061
Page 46	Line 3	6.9%	7.2%
Page 46	Line 8	Exhibit ACC-2, Schedule 26	Exhibit ACC-2, Schedule 26 Revised

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200051-GU

IN RE: PETITION FOR BASE RATE INCREASE BY

PEOPLES GAS SYSTEM

CONFIDENTIAL

PREPARED DIRECT TESTIMONY AND EXHIBITS

OF

ANDREA C. CRANE

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

August 31, 2020

Table of Contents

LIST OF EXHIBITS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 2805 East Oakland Park Boulevard, #401, Ft. Lauderdale, FL 33306.

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

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony over the past five years is included in Exhibit ACC-1.

Q. Have you previously testified in regulatory proceedings in Florida?

A. No, this is the first time that I am submitting testimony in a proceeding before the Florida Public Service Commission ("PSC" or "Commission")..

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On June 8, 2020, Peoples Gas System ("Peoples" or "Company"), filed a Petition with the Commission seeking a base revenue increase of $85.3 million, or approximately 34.8%. This increase includes the effect of rolling-in to base rates approximately $23.6 million annually that is currently being collected through a Cast Iron / Bare Steel Rider ("CI/BSR") that was authorized by the PSC in Order No. PSC-2012-0476-TRF-GU. Therefore, the net impact of the Company's request is a net revenue increase of approximately $61.7 million or 22.9%. PGS is proposing to increase residential rates by slightly more than the system average. The Company is proposing a residential ("RS") revenue increase of 36.8%, or 25.0% after consideration of the CI/BSR roll-in.

The Company's filing is based on a Historic Base Year ending December 31, 2019, and on a Projected Future Test Year ending December 31, 2021. Hence, the entire Future Test Year is forecast in this case. PGS is requesting a return on equity of 10.75% and a capital structure consisting of 54.7% common equity (excluding customer deposits and deferred income taxes). The Company's last base rate case was filed in Docket No. 20080318-GU and was based on a 2009 Projected Test Year. That case was resolved with a Commission Order on April 5, 2010.

In addition to this base rate filing, on June 8, 2020, PGS also filed a Petition (Docket No. 20200166-GU) requesting approval of new depreciation rates for its gas system. On June 22, 2020, the Commission consolidated the depreciation case with the base rate case.

The Columbia Group, Inc. was engaged by the Office of Public Counsel ("OPC") to review the Company's Petition and to provide recommendations to the Commission regarding revenue requirement issues. In addition, David Garrett is sponsoring testimony on behalf of the OPC regarding cost of capital and capital structure issues, and depreciation issues.

Q. What are the most significant issues in this rate proceeding?

A. The most significant financial issues include the Company's request to utilize a fully-forecast Projected Future Test Year; its request to reflect in rates significant capital expenditures projected over a 2 year period; and the Company's requested 10.75% return on equity. The Company is also seeking increases to its depreciation rates, significant increases in labor costs, including $4.3 million for additional employees, as well as increases in Transmission Integrity Management Program ("TIMP") pipeline assessment costs, insurance premiums, storm damage costs, and manufactured gas plant ("MGP") remediation costs.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending December 30, 2019, is an acceptable Base Year to utilize in evaluating the reasonableness of the Company's claim.
2. Given the fact that the Company is using a fully-forecast Projected Test Year, consisting of the twelve months ending December 31, 2021, the PSC should be especially cautious in evaluating the projections contained in the Company's Petition.
3. As discussed in the testimony of Mr. Garrett, the PSC should authorize a pro forma cost of equity of 9.50% for PGS, and a capital structure consisting of no more than 54.7% common equity (excluding customer deposits and deferred income taxes), resulting in an overall cost of capital of 6.05% (see Exhibit ACC-2, Schedule 2). [1]
4. PGS has a pro forma, Future Test Year rate base of $1.495 billion (see Exhibit ACC-2, Schedule 3).

[1] Exhibit ACC-2 contains my Revenue Requirement schedules. Schedule 1 and Schedule 26 are Revenue Requirement Summary Schedules, Schedules 2 to 6 are Rate Base Schedules, and Schedules 7 to 25 are Operating Income Schedules.

5. PGS has pro forma, Future Test Year operating income at present rates of $58.8 million (see Exhibit ACC-2, Schedule 7).

6. Based on my recommended adjustments, the Company has a pro forma, revenue deficiency of no more than $42.3 million, as shown on Exhibit ACC-2, Schedule 1. This is in contrast to PGS' claimed deficiency of $85.3 million.

7. After consideration of the roll-in of approximately $23.6 million related to the CI/BSR, the net impact is a revenue increase of no more than approximately $18.6 million.[2]

8. In addition to the adjustments discussed in my testimony, the Commission should also reflect a parent company interest adjustment in the Company's revenue requirement. Staff requested that the Company quantify such an adjustment in Staff IRR-37, and we are currently awaiting a response to that request.

9. The Company's request to increase its annual storm damage accrual from $57,500 to $380,000 is not unreasonable. In addition, the Company's request to increase the annual amortization expense of the MGP regulatory asset from $640,000 to $1,000,000 is not unreasonable.

Q. Are you in agreement with all of the components of the Company's revenue requirement claim, other than those specifically discussed in your testimony?

A. No, not necessarily. I focused on the major issues in the case or issues that I believe

2 The $23.6 million was based on the Company's requested ROE, so the actual net impact of the roll-in may be slightly different.

have important policy considerations. In addition, the procedural schedule in this case required my testimony to be filed less than three months after the Company's Petition was filed, and less than eight weeks after we received responses to our initial discovery. This compressed procedural schedule did not allow me to undertake as much discovery or as detailed an analysis as I usually do in utility rate proceedings. Therefore, if a specific issue or methodology is not addressed in my testimony, it does not necessarily mean that I support the Company's position on that issue or ratemaking methodology. There may also be adjustments raised by other parties to this proceeding that have merit and that should be adopted by the Commission. For this reason, I have identified my calculated revenue deficiency as a maximum.

In addition, in some cases, the Company has utilized methodologies with which I may disagree but which have been accepted by the PSC in the past, and which I chose not to address in this testimony. Accordingly, the PSC should not assume that the OPC is necessarily in agreement with all issues that are not otherwise addressed in my testimony.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company is requesting an authorized return on common equity of 10.75%, and a capital structure consisting of 54.7% common equity to total debt plus equity. The capital structure also includes customer deposits and deferred income taxes. Based on its proposed capital structure and cost rates, PGS is requesting an overall authorized return of 6.63%, as shown below:

	Percent	Cost	Weighted Cost
Long Term Debt	32.07%	4.47%	1.43%
Short Term Debt	6.27%	2.80%	0.18%
Customer Deposits	1.64%	2.51%	0.04%
Common Equity	46.30%	10.75%	4.98%
Deferred Taxes	13.71%	0.00%	0.00%
Total			6.63%

Q. **What is the overall cost of capital that that the OPC is recommending in this case?**

A. OPC is recommending an overall cost of capital of 6.05%, based on the following capital structure and cost rates:

	Percent	Cost	Weighted Cost
Long Term Debt	32.07%	4.47%	1.43%
Short Term Debt	6.27%	2.80%	0.18%
Customer Deposits	1.64%	2.51%	0.04%
Common Equity	46.30%	9.50%	4.40%
Deferred Taxes	13.71%	0.00%	0.00%
Total			6.05%

OPC's recommended cost of capital is based on the capital structure filed by the Company and on a recommended cost of equity of 9.5%, as discussed in the testimony of David Garrett. This is the cost of capital that I have incorporated into my revenue requirement schedules, as shown in Exhibit ACC-2, Schedule 2.

V. RATE BASE ISSUES

Q. **What Test Year did the Company utilize to develop its rate base claim in this proceeding?**

A. The Company selected the Future Test Year ending December 31, 2021. Therefore, the Company's rate base claim includes 2 years of projected plant additions (for the years 2020 and 2021). The use of a fully-forecast Future Test Year requires a subjective analysis, since no party in this case knows with certainty what the Company's actual investment will be during this time.

Q. What are the major components of the Company's rate base claim?

A. The Company's rate base claim includes two major components — net utility plant in service and working capital. Net utility plant includes gross utility plant in service, common plant that is allocated to PGS, authorized acquisition adjustments, and construction work in progress, offset by accumulated depreciation and amortization and by customer advances. The Company's allowance for working capital includes all other balance sheet components except for customer deposits and deferred income taxes, which are included in capital structure. The Company's rate base is based on a thirteen-month average balance during the Projected Future Test Year.

Q. How does the Company's rate base compare to the rate base authorized in its last base rate case?

A. The Company's filing reflects explosive growth in its rate base between the Commission order in PGS' last rate case and the present filing. As shown in Schedule A-3 to its filing, the Company's rate base is projected to grow by approximately 182% between 2009 and 2021, largely driven by increases in gross plant and construction work in progress. What is perhaps more significant to note is that much of this growth is projected to occur between the Historic Base Year and the Projected Test Year in this case:

	Growth 2009-2019	Growth 2019-2021
Gross Plant in Service	74.43%	31.63%
CWIP	44.57%	485.82%
Total	73.89%	38.51%

Gross plant and CWIP increased by 73.89% from 2009 to 2019 and is projected to increase by another 38.51% in the two-year period between the Historic Base Year and the Projected Test Year in this case. Thus, while there are 12 years between the Projected Test Year in the last case and the Projected Test Year in this case, a disproportionate amount of the rate base growth is due to the two years of projections included by PGS in this case. It is also worth further noting that the Company has indicated it may file another rate case in 2022 with a 2023 projected test year.[3]

Q. **How do the Company's 2020 and 2021 capital budgets compare with the amounts traditionally budgeted by PGS?**

A. As shown in its response to OPC IRR-30 and Exhibit SPH-1 (Document No. 6), the Company's capital budgets have increased dramatically over the past five years, and additional growth is projected for 2020 and 2021:

	Approved Capital Budget ($000)
2015	$103,970
2016	$106,539
2017	$148,892
2018	$195,929
2019	$240,014
2020	$358,693
2021	$263,805

3 PGS response to OPC POD No. 34 at Bates No. 5212.

The Company's projected spending of $358.693 million in 2020 is approximately 50% more than the capital budget in any of the prior five years. While the Company's 2021 capital budget is somewhat lower than the 2020 projection, it is still very high relative to historic levels.

PGS has stated that its 2020 capital budget is largely related to four projects: the Panama City Expansion Project, the Southwest Florida Expansion Project, the Jacksonville Expansion Project, and a new Liquefied Natural Gas ("LNG") facility in Miami. These four projects comprise $117.62 million of the 2020 capital budget and $15.37 million of the 2021 capital budget, as shown in the Company's response to OPC IRR-100.

Even if these four projects are excluded, the 2020 and 2021 capital budgets are high relative to capital budgets prior to the Base Year in this case. Given the Company's expressed interest in entering into new and potentially competitive markets, such as the LNG market, the Commission should be especially vigilant to ensure that projected capital projects are necessary for safe and reliable regulated gas service, and are not being undertaken in order to position PGS to expand into speculative activities or to enter competitive markets.

Q. **Are you recommending any adjustments to the net plant-in-service additions projected by PGS in its filing?**

A. Yes, I am recommending an adjustment. It is important to keep in mind that the Company's utility plant-in-service claim is largely based on projections, including costs for many projects that will not even be started by the time that new rates are effective in this case. Given the use of a Future Test Year, there is uncertainty inherent in the Company's projected plant additions. In addition, the capital budgets on which these projections are based reflect spending that far exceeds the Company's historic capital spending. Moreover, the current COVID-19 pandemic is likely to result in at least some construction delays. Therefore, even if the Company's projections were accurate when it prepared its 2020 and 2021 capital budgets, there are likely to be some delays in project completion. For all these reasons, some adjustment to the Company's net plant-in-service claim is warranted.

Q. Does it appear that there have been delays in specific projects?

A. Yes, it does. As previously noted, when it filed its testimony PGS identified four major projects that were responsible for a significant portion of the incremental 2020 capital budget. In its pre-filed testimony filed on June 8, 2020, PGS indicated that three of these projects (Panama City, Southwest Florida, and Jacksonville expansion projects) were projected to be in-service by December 2020. In addition, the Company indicated the Miami LNG facility was projected to go into service in June 2021.

In discovery responses provided a few weeks later, PGS indicated that, while the Panama City and Jacksonville projects are still expected to be in-service by the end of 2020, a portion of the Southwest Florida project is now projected to be delayed until March 2021 and the Miami LNG facility is not expected to go into service until April of 2022. Moreover, since those responses were filed, the COVID-19 crisis in Florida has intensified. In addition to delays in these major projects, there are likely to be additional delays in other areas of the Company's capital program, especially when one considers how aggressive the capital program is relative to historic expenditures. Therefore, some adjustment to the Company's proposed revenue requirement is appropriate.

Q. How did you quantify your adjustment?

A. Since the Company's claim is based on speculative projections, any adjustment to that claim will also be subjective. Accordingly, I am recommending that the Company's projected plant-in-service balance at December 31, 2020, be used to set rates in this case. At Exhibit ACC-2, Schedule 4, I have made an adjustment to reduce the Company's projected gross utility plant balance from the average Projected Test Year balance reflected in the filing to the projected balance at December 31, 2020.

Q. How did you incorporate the additional Future Test Year Adjustments made by the Company in Schedule G-1, page 4?

A. I examined each of the adjustments made by the Company in Schedule G-4 to determine if they were impacted by the use of the December 31, 2020, plant balances and, if so, I further adjusted my recommended gross plant-in-service balance to prevent any double-counting of adjustments. In some cases, the use of the December 31, 2020, plant balances did not necessitate any change to the rate base adjustments made by the Company; e.g., the acquisition adjustment was not dependent on the amount of gross plant added in the Future Test Year. However, the Company's CI/BSR adjustment of $16,488,118 (per Schedule G-1, page 4) was largely based on projected Future Test Year additions. Therefore, as shown on Exhibit ACC-2, Schedule 4, I reduced my recommended adjustment by $16,488,118 in order to avoid double-counting the removal of the 2021 CI/BSR plant.

In addition, the Company's adjustment to exclude non-utility common plant was based on its projected 2021 plant additions. Therefore, I also made an adjustment to non-utility common plant to synchronize the common plant allocated to PGS with the plant additions that I recommend be reflected in rate base. This adjustment was based on the Company's response to OPC IRR-114, and it also included in Exhibit ACC-2, Schedule 4.

Q. Please describe your adjustment to construction work in progress ("CWIP").

A. Similar to my recommended adjustment relating to gross plant, I made a similar adjustment to reflect the Company's projected December 31, 2020, CWIP balance in rate base. My adjustment is shown in Exhibit ACC-2, Schedule 5. Once again, I reviewed the Company's rate base adjustments to determine if any further adjustment was necessary to properly reflect the proposed adjustments shown on Schedule G-1, page 4 of the Company's filing. In the case of CWIP, I made two further adjustments. First, I reversed the Company's proposed adjustment relating to CI/BSR plant, for the reasons stated above. Second, I reduced my adjustment by a portion of the Company's adjustment relating to the CWIP that is eligible to accrue an allowance for funds used during construction ("AFUDC"). Both of these adjustments are shown in Exhibit ACC-2, Schedule 5.

Q. How did you quantify the AFUDC adjustment?

A. At Schedule G-1, page 4, the Company reduced its rate base claim by $30,814,451 to account for CWIP that is eligible to accrue AFUDC. In the response to OPC IRR-114, the Company identified the CWIP eligible to accrue AFUDC that was associated with its December 31, 2020 plant balance. I used this data to quantify my AFUDC adjustment to the Company's CWIP claim.

Q. How do the plant balances contained in your recommendation compare with historic spending?

A. My recommendation results in an increase in gross plant-in-service and CWIP of approximately $570 million from the Base Year to the Projected Test Year. This is still a very significant increase relative to the Company's historic spending levels and demonstrates the reasonableness of my adjustment. Moreover, if the Commission determines that the Company's rate base claim has been inflated due to capital expenditures undertaken to better position PGS with regard to speculative competitive activities, additional adjustments may be appropriate.

Q. Did you make a corresponding adjustment to the Company's reserve for depreciation and amortization?

A. Yes, I did. Consistent with my adjustments to utility plant-in-service and CWIP, I also made an adjustment to reduce the Company's reserve for depreciation and amortization. PGS reflected an average Projected Test Year balance in its claim. I have utilized the December 31, 2020, reserve balance in my rate base recommendation. My adjustment is shown in Exhibit ACC-2, Schedule 6.

In addition, my adjustment to accumulated depreciation also reflects corresponding revisions to the Company's adjustments relating to the CI/BSR and non-utility common plant, as discussed above.

Q. Doesn't your recommendation effectively move the Test Year up by one year, from calendar year December 31, 2021, to calendar year December 31, 2020?

A. No, it does not. While the Company's filing is based on the Projected Test Year ending December 31, 2021, the Company reflected average Test Year balances in its rate base claim. Assuming the Company added plant consistently during the year, the Company's filing would effectively represent plant balances at June 30, 2021, the midpoint of the Projected Test Year. Since I am recommending that the PSC utilize Projected Plant Balances at December 31, 2020, my recommendation essentially represents a difference of only six months from the Company's claim.

The purpose of my adjustments is not to change the Test Year selected by the Company. It is simply to update the capital spending anticipated for that Test Year. The data that was originally projected by the Company at December 31, 2020, is a proxy for my recommended adjustments during the Projected 2021 Test Year. Given the extremely ambitious capital program proposed in the filing, the inherent speculative nature of any projected test year, and the unique economic situation that is currently evolving in Florida, it is reasonable and appropriate for the PSC to set rates based on a less ambitious capital program. This is even more appropriate when you consider the Company intends to file another base rate case in 2022, just two years into the future, with a 2023 Projected Test Year.

Q. What is the net impact on rate base of the plant-in-service, CWIP, and reserve adjustments that you are recommending in this case?

A. As shown in Exhibit ACC-2, Schedule 3, my recommendations will result in a rate base reduction of $83.8 million. Applying the cost of capital recommended by Mr. Garrett, my rate base recommendations will reduce the Company's revenue requirement by approximately $6.3 million.

Q. Did the OPC adjust its recommended capital structure to reflect the impact of your plant-in-service adjustments on deferred taxes?

A. No, we did not. I did, however, review the percentage of deferred taxes in the Company's capital structure from the Historic Base Year through the Projected Future Test Year to ascertain the change in the percentage of deferred taxes during this period. The Company's Future Test Year capital structure contains 13.71% deferred income taxes, less than the Historic Base Year percentage.

The calculation of deferred tax reserve balances is very complex and would require input from the Company. If the Company believes that a further adjustment is necessary, I will work with PGS to determine the impact of my recommendations on the proposed capital structure prior to the Company filing its Rebuttal Testimony in this case.

Q. Do your adjustments impact the continued operation of the Company's CI/BSR?

A. My adjustments are not intended to impact the continued operation of the CI/BSR. The Company will continue to reflect future rate adjustments based on the amount of investment made pursuant to this rider mechanism. Therefore, in addition to any base rate increase that would result in this case, I expect that customers will experience additional annual increases related to the CI/BSR.

Q. Do you have any additional comments regarding the Company's utility plant-in-service claim?

A. Yes, as noted earlier, one of the four major projects that the Company included in its filing is a new LNG facility in Miami. I understand that PGS has filed a separate Petition in Docket No. 20200093-GU for approval of a tariff to provide LNG services to third parties. That proceeding is currently on-going.

The Company's LNG Tariff Petition raises serious questions about whether the Company should provide such services to third parties and if so, how the associated costs should be recovered. Until those issues are resolved, it would be premature to include either capital or operating costs associated with the Miami LNG facility in the Company's rates that result from this general rate case. PGS claims that the Miami LNG facility is being undertaken primarily in order to meet a pipeline constraint in the Miami area during peak summer hours. However, given the cruise ship business in Miami, the accessibility from Miami to various locations in the Caribbean, and the relatively small number of hours that the Miami LNG facility would be needed to serve native load, it would be naïve to assume that the Miami LNG facility would have no role in the new, competitive LNG business envisioned by PGS. The Commission may find that LNG services should be provided on an unregulated basis, or find that other ratepayer protections should be implemented to ensure that regulated natural gas customers do not subsidize LNG activities.

Furthermore, my adjustment to include no more than the December 31, 2020 plant-in-service balance in the required revenue requirement also recognizes the

Company has not demonstrated that the overall level of additions to transmission and distribution facilities are adequately allocated to any demands placed on the system by the Company's planned entry into the facilities-based competitive provision of LNG services under the proposed tariff. The Company has acknowledged that any such LNG facility demand-related capital costs should be allocated to, and captured in, the revenues collected to cover such competitive entry by the Company. However, at this point PGS has not demonstrated that competitive LNG service impacts have been removed from plant allocated to the general body of customers.

Q. If the Commission decides that the costs associated with LNG services should be excluded from the Company's revenue requirement in this case, what impact would that decision have on your recommended revenue increase?

A. Such a decision would not change my recommended revenue increase in this case. My recommendation is based on plant balances at December 31, 2020, as a proxy for the Future Test Year balances. Since the Company does not expect the Miami LNG facility to be in-service by the end of 2020, there should be no gross plant associated with the Miami LNG facility in the Company's December 31, 2020, utility plant balance. Moreover, PGS excluded CWIP that is eligible to accrue AFUDC from its rate base claim. Since the majority of the Miami LNG capital costs appear to be eligible for AFUDC, there should be no, or very little, CWIP associated with the Miami LNG facility included in rate base at December 30, 2020. Finally, I am recommending that operating expenses and other related expenses associated with LNG activities be excluded from the Company's revenue requirement, as discussed later in this testimony. Therefore, if the Commission rejects the Company's request to provide LNG services pursuant to a tariff, no further adjustment to my revenue recommendation would be necessary, unless the Commission or other parties identify additional costs related to LNG activities that are embedded in the Company's filing.

VI. OPERATING INCOME ISSUES

Q. How have the Company's operating and maintenance costs changed since the last base rate case?

A. Costs between the 2009 Test Year used in the Company's last base rate case and the 2019 Base Year in this case have increased by more than the "O&M Benchmark" approach that has been used by the Commission in the past to evaluate operating expense increases between base rate case filings. As discussed starting on page 29 of Sean Hillary's testimony, actual Base Year operating and maintenance costs were $107.2 million, approximately $7.8 million higher than the calculated benchmark of $99.2 million using customer-growth and the CIP inflation index. This represents an excess of almost 7.9%.

In addition, the Company's Projected Future Test Year operating costs of $121.3 million are 13.2% higher than the Historic Base Period costs of $107.2 million. Most of this increase is projected to occur in 2021, since the Company projects less than a 1% increase from the Historic Base Period to 2020.

Q. How did the Company determine its Projected Future Test Year operating and maintenance costs?

A. The Company's costs are based on its budgeted costs for 2021. The Company claims that it verified the reasonableness of its 2021 budget by comparing the 2021 budgeted costs to costs that were adjusted based on a series of trending factors. Basically, PGS grouped its Projected Future Test Year costs into one of four categories: Trended Labor, Payroll Not Trended, Other Trended Costs, and Other Costs Not Trended.

Q. How were each of these adjusted by PGS?

A. The Company applied different methodologies to each category of costs. For Trended Labor costs, PGS applied a 3% annual increase from the Historic Base Period to the Projected Future Test Year. For Other Trended Costs, the Company applied either an annual Customer Growth Rate X Inflation factor or just an Inflation Factor to determine the increases between the Historic Base Period and the Projected Future Test Year. For Payroll Not Trended and Other Costs Not Trended, the Company used the 2021 budgeted amounts.

Q. Are you recommending any adjustments to the Company's operating and maintenance costs?

A. Yes, I am recommending adjustments to several categories of operating and maintenance costs. I am not recommending any adjustment to Trended Labor Costs. However, I am recommending that labor costs for new employees (Payroll Not Trended) be excluded from the Company's revenue requirement, as discussed below. I am also recommending adjustments to Other Trended Costs relating to inflationary increases and to membership dues expenses. Finally, I am recommending several adjustments to Other Costs Not Trended relating to LNG and Economic Development Expense, Advertising and Marketing Expense, Rate Case Costs, and others. Each of these adjustments will be discussed in more detail below.

A. Labor Costs – Additional Employee Expense

Q. Please describe the payroll costs included in the Company's operating and maintenance expense claim.

A. PGS included $36.8 million of payroll expense based on increasing the adjusted Base Period payroll costs by 3% annually. In addition, the Company included approximately $4.3 million for new employee positions. According to the testimony of Mr. O'Connor at page 38, "[a]s Peoples' system and the state of Florida move toward increased use of CNG, LNG, and RNG, Peoples needs additional expertise in the implementation and development of CNG, LNG, and RNG, as well as, the data analytics and research that support these initiatives." I am recommending that the $4.3 million in new employee positions, as well as related taxes and supporting expenses, be excluded from the revenue requirement authorized in this case.

Q. What is the basis for your adjustment?

A. The Company's claim for new positions reflects an increase of approximately 12.4% over the Historic Base Year payroll costs. While these costs may be included in the Company's budget, historically PGS has not filled all of its authorized positions over the past few years. In fact, the Company has not even come close to filling all its authorized positions. As shown in its response to OPC IRR-4, the Company's actual employee count through the first five months of 2020 was approximately 7.5% less than authorized. Similarly, actual employee positions were well below authorized levels in 2018 and 2019. In this case, the Company is requesting an increase of 104 new positions from the actual average Base Year employee levels, or an increase of approximately 17.8%.

In addition, PGS has not justified the need for these additional employees in its filing. While the Company points to CNG, LNG, and RNG as drivers of the need for these new positions, the Company has not yet received approval for its LNG Tariff, nor has the Company reflected revenues from these activities that would justify the need for additional personnel. While these additional employees may be an aspirational goal for PGS, neither its past experience nor its Future Test Year projections suggest the need for an employee increase of this magnitude. Moreover, the Company's proposed increase in these costs would mean that costs for ramping up the competitive LNG tariffed service would be embedded into ongoing base rates. These costs could not be allocated to the contracts with any of the Company's prospective competitive LNG customers without reducing base rates. Limiting the payroll-related O&M reduces the risk that the general body of customers will be forced to bear the competitive service costs if the LNG Tariff is approved. Therefore, at Exhibit ACC-2, Schedule 8, I have made an adjustment to eliminate the Company's claim for these new positions from its revenue requirement.

B. Incentive Compensation Award Expense

Q. Please describe the Company's incentive compensation award programs.

A. PGS has two short-term incentive compensation programs, the Performance Sharing Program ("PSP") and the Balanced Scorecard Incentive Program. The PSP is available to hourly and exempt employees, including supervisors, while the Balanced Scorecard

Incentive Program is available to employees at the level of manager and above. Both of these programs provide cash awards to participants.

The PSP has a potential payout of 12% of base pay, 50% of which is based on financial benchmarks. The remaining payout is based on other benchmarks such as safety goals, employee development goals, customer service goals, and asset management goals. The Balanced Scorecard Incentive Program has similar benchmarks; however, the weighting of each benchmark differs slightly from the weightings used in the PSP.

In addition, the Company has a long-term incentive compensation program that is available to a very small number of officers and key employees. The long-term incentive compensation program is a stock award program. Fifty percent (50%) of the awards are performance-based, meaning that the awards are tied to the financial performance of Emera stock. In addition, the performance-based awards are also subject to a performance modifier, based on how Emera's average three-year total shareholder return compares with a proxy group of other utility companies. The remaining 50% of the long-term incentive awards are restricted share units and vest after three years. The restricted share units are not based on the achievement of any specific benchmarks or performance standards but are offered at the discretion of the Board.

Q. How many employees participate in each of the incentive compensation programs?

A. According to the response to OPC IRR-10, there are 555 participants in the PSP and

19 participants in the BSC. There are also 30 officers/key employees that participate in both the BSC and the long-term incentive award plan.

Q. How much did the Company include in its filing relating to incentive compensation awards?

A. As shown in its response to OPC IRR-10, the Company included $4,512,108 for short-term incentive compensation awards in its filing, which includes $477,443 associated with officers. This results in an average short-term incentive compensation award of approximately $7,500. In addition, the Company included $1,558,657 of long-term incentive compensation costs in its filing. Based on the 30 officers/key employees eligible for these awards, the average long-term incentive compensation award included in the filing is almost $52,000 per participant.

Q. How did the Company develop its claim for incentive compensation award costs?

A. The short-term incentive compensation awards are targeted to a percentage of each employee's eligible earnings. The long-term incentive awards are based on either pre-determined percentages of an officer's base salary or on fixed dollar amounts.

Q. Are you recommending any adjustment to the Company's claim for incentive compensation award costs?

A. Yes, I am recommending that the incentive compensation award costs that are tied to financial metrics, or which do not otherwise benefit ratepayers, be recovered from the Company's shareholders. Regulatory commissions frequently disallow incentive compensation costs tied to financial metrics on the basis that such metrics benefit shareholders, but may not benefit, and may even harm, ratepayers. In fact, PGS's affiliate, New Mexico Gas Company ("NMGC"), did not even seek recovery of long-term incentive compensation costs in its recent base rate filing. In addition, NMGC eliminated certain short-term incentive compensation costs tied to financial metrics from its claim. Awarding incentive compensation based on financial metrics is inconsistent with a utility's mandate to provide safe and reliable utility service at the lowest reasonable cost. In this case, not only is a portion of the Company's incentive compensation award costs tied to the financial performance of Emera, but it is also dependent upon the financial results of a proxy group of other utilities.

Q. How did you quantify your adjustment?

A. Approximately 50% of the Company's short-term incentive awards are based on financial metrics. Therefore, I have eliminated 50% of the Company's claim for the PSP and Balanced Scorecard Programs from my revenue requirement. I have also eliminated 100% of the long-term incentive compensation awards, since these awards are not tied directly to metrics that benefit ratepayers. My adjustments to incentive compensation award costs are shown in Exhibit ACC-2, Schedule 9.

C. Payroll Taxes and 401K Expense

Q. In addition to the Labor adjustment related to new employees and the Incentive Compensation Award adjustments discussed above, did you make corresponding adjustments relating to payroll taxes and 401K costs?

A. Yes, I did. On Exhibit ACC-2, Schedule 10, I have made a corresponding payroll tax adjustment, to reflect the impact on payroll taxes of my recommended adjustments to eliminate costs for new employee positions and to eliminate 50% of the short-term incentive compensation award costs. I did not include the long-term incentive compensation costs in my payroll tax adjustment, because these awards are not made in cash and potentially have different tax treatment. My payroll tax adjustment reflects the statutory payroll tax rate of 7.65%. In addition, it is my understanding the Company's 401K claim is based on total compensation, including short-term incentive compensation awards that are made in cash. Therefore, I made an adjustment in Exhibit ACC-2, Schedule 11 to eliminate the Company's 401K match on the labor and short-term incentive compensation costs that I recommend be disallowed.

D. Other Employee-Related Expense

Q. In addition to labor costs, are there other costs included in the Company's claim relating to new employee positions?

A. Yes, there are. As shown on Exhibit No. SPH-1, Document No. 5, PGS included several categories of non-labor costs in its revenue requirement claim that relate to the new employee positions that it is seeking in this case. In its response to OPC IRR-109, the Company identified $163,200 in Operation Employees Expenses and Materials costs, including travel, equipment, uniforms and other incidental expenses associated with additional employees. The Company also identified $98,000 in Additional A&G Employee expenses for "additional preventive staffing" in the Pipeline Safety Compliance Department. PGS included $607,242 in incremental Information Technology costs, $264,994 in incremental Human Resources costs, and $65,652 in other incremental Shared Services expense, all of which represent increased allocations from Tampa Electric due to projected increases in employee headcount. These employee-related costs total $1,181,088.

Since I am recommending that the Commission reject the Company's claim for significant new employee additions, I have made a corresponding adjustment to eliminate these costs that are either directly related to increased staffing, or are related to increased allocations from Tampa Electric as a result of the headcount. Even if PGS does increase its employee base, there is no indication that this increase would exceed changes in employee counts at Tampa Electric, or other entities that are allocated costs from Tampa Electric. Therefore, at Exhibit ACC-2, Schedule 12, I have made an adjustment to eliminate these employee-related costs from my revenue requirement recommendation.

E. Other (Non-Labor) Trended Expense

Q. Did the Company utilize a general escalator to project certain Future Test Year costs?

A. Yes, it did. The Company's Adjusted Base Period operating and maintenance costs totaled $107.2 million. The Company utilized inflation trends to support adjustments of $44.1 million or approximately 41% of these costs. Two factors were used by PGS. Certain costs were adjusted by a Customer Growth X Inflation factor, while other costs were adjusted solely by the Inflation factor. In both cases, the Company utilized 2.2% annual inflation. According to the testimony of Sean Hillary at page 36, the Company utilized Moody's Economy.com's 2020 and 2021 forecast for the CPI-U (Consumer Price Index for all Urban Consumers) as the inflation factor applied to these costs.

Q. Are you recommending any adjustments to Other (Non-Labor) Trended Costs?

A. Yes, I am recommending two adjustments. First, I am recommending an adjustment to all costs that were trended on a CPI-U inflation factor. Second, I am recommending an additional adjustment to the Historic Base Year Membership Dues Expense, which was also subject to the CPI inflation factor.

Q. Do you believe that the use of 2.2% annual escalation factor is reasonable?

A. No, I do not. While Florida utilities have the ability to file a base rate case using a future test year, that right does not relieve a utility from filing rates that are cost-based and that are linked to an historic Base Period through some reasonable means. PGS has not demonstrated that the expenses to which the general escalator was applied necessarily trend with the CPI-U, or necessarily increase at all over time.

However, even if one assumes that a general escalator is appropriate, it should not be based on speculative projections of future increases. A better approach would be to examine the historic 12-month averages. As reported by the Bureau of Labor Statistics, the CPI-U for the twelve months ending July 2020 was 1.0%, less than half the adjustment reflected in the Company's filing. More importantly, the CPI for Energy Services was -0.1%, indicating a decline in energy costs over the prior year. The CPI for Gas Service showed a greater reduction of -0.3% annually. There is no doubt that these results have been impacted by the COVID-19 pandemic. However, there is no indication that economic activity will turn around and result in a 2.2% increase in the 2020 CPI by the end of the year, followed by an additional increase of 2.2% in 2021.

Q. What do you recommend?

A. Given the speculative nature of adjustments that rely upon a general escalator, the fact PGS has not demonstrated that certain costs trend in line with the CPI-U, as well as the actual CPI results over the past twelve months, PGS has not shown that the use of a 2.2% general escalation factor is appropriate. Therefore, I recommend the Commission reject the general escalator reflected in the Company's cost of service. My adjustment is shown in Exhibit ACC-2, Schedule 13.

F. Membership Dues Expense

Q. Has the Company included any membership dues expenses in its revenue requirement claim?

A. Yes, as shown in Schedule C-11 to the Company's filing, PGS incurred membership dues expenses of $922,483 in the Historic Base Period. The Company made certain adjustments to remove amounts classified as lobbying. The remaining costs were inflated by the annual inflation factor of 2.2% discussed above.

Q. Are you recommending any adjustment to the Company's claim for membership dues expenses?

A. Yes, I am recommending two adjustments. First, I am recommending that 20% of dues to the American Gas Association ("AGA") be excluded from regulated rates. Second, I am recommending an adjustment to remove additional lobbying costs from the Associated Gas Distributors of Florida that were erroneously included by the Company in its revenue requirement claim.

Q. Please describe your first adjustment.

A. The Company's Historic Base Year dues expense included $221,966 paid to the AGA. PGS excluded $8,050 of this amount from its revenue requirement, on the basis that this was the amount identified by the AGA as constituting lobbying. However, in addition to the narrowly-defined "lobbying" activities undertaken by AGA, it is clear that AGA participates in other advocacy activities that are designed to promote shareholder interests. For example, core strengths listed on AGA's website include such activities as "advocacy for natural gas industry issues, regulatory constructs and business models that are priorities for the industry," the promotion of "growth in the efficient use of natural gas by emphasizing before a variety of stakeholders the benefits of clean, abundant natural gas as part of the solution to the nation's energy and environmental goals," "collects, analyzes and disseminates information to opinion leaders, policy makers and consumers about the benefits provided by energy utilities and the natural gas industry," and delivery of "measurable value to AGA members." AGA actively solicits support from the National Association of Regulatory Utility Commissioners ("NARUC") and promotes a "favorable regulatory climate for gas utilities." It arranges meetings between regulators and the financial community "educating state regulatory commissioners on how their decisions impact the views of the financial community. . . ." Advocacy, both formal advocacy through its formal lobbying program and informal advocacy with regulatory commissions and other stakeholders, is a significant part of the AGA's activities. The Company's adjustment of $8,050 clearly understates the volume of AGA activities that promote shareholder interests. Accordingly, I am recommending a further adjustment to the Company's claim.

Q. How did you quantify your adjustment?

A. Based on a review of AGA documentation and my experience in other rate proceedings, I recommend that 20% of AGA's annual dues, or $44,393, be disallowed. Since the Company has already reflected an adjustment to eliminate $8,050 from its claim, I am recommending an additional adjustment of $36,343. My adjustment is shown in Exhibit ACC-2, Schedule 14.

Q. Please describe your second adjustment to the Company's claim for Membership Dues Expense.

A. In its response to OPC IRR-28, the Company indicated it had paid $50,000 in dues to the Associated Gas Distributors of Florida. $25,000 of this amount was booked below-the-line as a lobbying expenditure. The remaining $25,000 was included in the Company's revenue requirement in this case, and escalated based on the Other Trended inflation factor. However, in this response, the Company indicated that the entire $50,000 should have been classified as lobbying and excluded from the Company's claim. Therefore, at Exhibit ACC-2, Schedule 14, I have also made an adjustment to exclude the additional $25,000 from the Associated Gas Distributors of Florida from the Company's revenue requirement. Since I have already made an adjustment relating to the Other Trended inflation factor, my adjustment is limited to the $25,000 incurred in the Historic Base Period.

G. (Non-Labor) Costs Not Trended

Q. Please summarize the Company's claim for Non-Labor Costs Not Trended.

A. As shown in Sean Hillary's Exhibit No. SPH-1, Document No. 5, there are many categories of non-labor costs that were not trended by inflation or customer growth factors, but instead were separately adjusted by PGS. The Company incurred actual costs in the Historic Base Year for these activities of $28.4 million. While these costs are projected to decline to $24.1 million in 2020, PGS has projected explosive growth to $32.9 million by 2021.

As discussed in more detail below, I am recommending several adjustments to these non-labor costs. However, with one exception (TIMP-Pipeline Reassessment and Risk Analysis), I am not recommending any adjustment to cost categories for which the Company actually incurred costs in the Historic Base Year. My concern is primarily with cost categories that were not included in the Historic Base Year and instead have been incrementally added to the 2021 budget, which was used to develop the revenue requirement in this case. It is not unusual for operating budgets to contain amounts that utility managers would like to see approved – rather than amounts that are actually necessary for the provision of safe and adequate utility service at the lowest reasonable cost. Based on the lack of demonstrated support for these items, I am recommending a number of adjustments as discussed below. My adjustments generally fall into five broad categories:

- LNG and Economic Development Expense
- Advertising and Marketing Expense

- Rate Case Expense
- TIMP Pipeline Reassessment and Risk Analysis
- Other Non-Labor Costs Not Trended

1. LNG and Economic Development Expense

Q. Please describe the 2021 incremental Miami LNG Storage costs and Economic Development costs included in the Company's claim.

A. The Company has included $25,000 of Miami LNG Storage Costs, $50,000 of LNG/RNG Consulting costs, and $415,802 of new economic development activities in its filing. I am recommending that all of these costs, totaling $490,802, be disallowed.

Q. What is the basis for your recommendation?

A. With regard to LNG costs, the Company has not yet received approval of its LNG Tariff and there is some question as to whether these costs should be borne by PGS' ratepayers in Florida. Even if the LNG Tariff is approved, the Miami LNG facility will not be in-service during the Future Test Year in this case and revenues from that facility have not been reflected in the filing.

With regard to economic development activities, PGS has not provided detailed support for these incremental expenditures. In addition, economic development in the Company's service territory is already strong, as evidenced by continued customer growth and expansion. The Company has not provided a compelling argument for why additional economic development funding of this magnitude is necessary or will be beneficial to the long-term provision of regulated utility service. Therefore, I recommend that these costs also be disallowed, as shown in Exhibit ACC-2, Schedule

15.

2. Advertising and Marketing Expense

Q. Did the Company also include incremental advertising and marketing costs in its revenue requirement claim?

A. Yes, it did. As shown in Exhibit SPH-1, Document No. 5, PGS included incremental customer communications costs of $35,000 in the Projected Future Test Year. The Company also included $829,871 of additional marketing costs to promote natural gas, and costs related to an additional pipeline awareness campaign of $200,000.

Q. In your opinion, has the Company justified the inclusion of these costs in the Projected Future Test Year?

A. No, it has not. The Company claims that the Additional Customer Communications costs of $35,000 will "improve customer experience through additional customer research and segmentation."[4] A similarly vague description is used to support the Company's claim for $829,871 in additional marketing to promote natural gas, where the Company indicated that the increased "marketing work is to promote the use of natural gas, improve customer retention and develop a more integrated approach to marketing Peoples' programs and services to current and potential customers." The Company has obviously been successful in its past marketing efforts, as evidenced by its relatively strong growth rate. PGS has not justified the need for more than $850,000 in incremental costs to promote these efforts.

4 Response to OPC IRR-109.

Finally, with regard to its request for an additional $200,000 in incremental pipeline safety awareness advertising, PGS has not demonstrated that its current safety awareness efforts are inadequate. While pipeline safety is an important goal, programs to promote pipeline safety should be necessary, targeted, and cost effective.

Q. What do you recommend?

A. I recommend that the additional advertising and marketing costs discussed above, in the amount of $1,064,871, be disallowed. The Company has provided only vague descriptions of these programs and has not demonstrated that additional programs in these areas are needed, or that the earmarked expenditures are reasonable. Therefore, at Exhibit ACC-2, Schedule 16, I have made an adjustment to eliminate these costs from my revenue requirement recommendation.

3. Rate Case Expenses

Q. Please describe the Company's claim associated with rate case costs for the current rate case.

A. PGS is seeking to recover $1,657,000 in rate case costs relating to the current rate case, as shown in Schedule C-13, page 1.

Outside Consultants	$764,500
Legal Services	$800,000
Other Expenses	$92,500
Total Rate Case Costs	$1,657,000

In response to OPC IRR-122, the Company provided a breakdown of its estimated consulting costs, as well as the hours and total costs billed to date:

Consultant	Estimated Cost	Billed to Date (including expenses)	Billed Hours
PWC	$105,000	$107,943	258.60
Scott Madden	$120,000	$41,806	140.50
Dan Yardley	$287,000	$128,700	390.00
Susan Richards	$95,000	$104,126	1,305.12
Alliance Consulting	$80,000	$39,963	195.75
Richard Harper/ Economic Consulting	$75,000	$18,061	54.75
Mercer	$2,500	$2,500	
Total	$764,500	$443,099	2,344.72

PGS is proposing to amortize these costs over three years, and has included annual amortization expense of $552,333 in (Non Labor) Costs Not Trended.

Q. What are the typical hourly rates for the consulting firms whose charges are included in the Company's rate case cost claim?

A. According to the response to OPC POD-3, there is a wide range of hourly billing rates for the consultants utilized by PGS, depending on the firm and the position within the firm of each consultant. Hourly rates generally range from a low of $65.00 per hour to a high of $575.00 per hour.

Q. Are you recommending any adjustment to the rate case costs being claimed by PGS for this proceeding?

A. I am not proposing any adjustment to the overall level of rate case costs being proposed by PGS in this case. However, I am recommending a longer amortization period. A three-year amortization period assumes that the utility will file a base rate case approximately every three years. However, the Company's last base rate was based on a 2009 future test year, 12 years prior to the test year in this case. While the Company contends that it plans to file another case in 2022, there is no assurance that it will actually do so.

Q. What amortization period are you recommending in this case?

A. I am recommending that rate case costs for the current case be amortized over five years, instead of over three years as proposed by the Company. While the Company's last base rate case was 12 years ago, I am not recommending an amortization period of longer than five years, given the possibility of a base rate case being filed within the next few years. However, given the rate case history of PGS, a five-year period is more reasonable than the three-year amortization period requested by the Company. My adjustment is shown in Exhibit ACC-2, Schedule 17.

4. TIMP Pipeline Reassessment and Risk Analysis

Q. What adjustment are you recommending to the Company's claim for $2,107,400 in TIMP Pipeline Reassessment and Risk Analysis Costs?

A. This is one area where I am recommending an adjustment to a cost category for which the Company also provided 2019 and 2020 actual expenditures on Exhibit SPH-1, Document No. 5. As shown in this exhibit, the Company incurred actual costs of $112,961 in the Historic Base Year and is projecting costs of $292,500 for 2020. However, PGS is seeking to include $2,107,000 in rates resulting from this proceeding.

According to the testimony of Sean Hillary at page 38, "the pipeline integrity compliance costs can vary from year-to-year depending on which pipelines are due for assessment and inspection." Witness Hillary goes on to state that PGS has scheduled several reassessments in 2021 at an estimated cost of $1.96 million. In addition, the Company "budgeted approximately $0.15 million for outside engineering assistance related to TIMP risk analysis assessments and plan updates."

Q. How do the 2021 projected costs compare with cost projections for later years?

A. As previously noted, the Projected Test Year costs are significantly higher than the costs incurred in 2019 or projected for 2020. In addition, the 2021 costs are also higher than costs projected in any other year during the 2021-2025 timeframe. Therefore, allowing the Company to include these costs in rates may result in a windfall in subsequent years as TIMP Pipeline Assessment costs decline.

Q. What do you recommend?

A. Given the fact that these costs can vary so significantly from year-to-year, as acknowledged by the Company, it would not be appropriate to include $2.1 million in prospective rates. When costs vary significantly from year-to-year, regulators frequently normalize such costs, in order to mitigate the fluctuations that occur. Based on the Company's representation that these costs vary from year-to-year, and on the significant increase being requested in 2021, I recommend that the Commission normalize these TIMP Pipeline Reassessment and Risk Analysis costs. At Exhibit ACC-2, Schedule 18, I have made an adjustment to reflect a five-year average of the anticipated TIMP Pipeline Reassessment and Risk Analysis costs, based on the Company's current schedule for 2021-2024.

5. **Other (Non-Labor) Costs Not Trended**

Q. What additional adjustments are you recommending to Other Non-Labor Costs Not Trended?

A. In addition to the costs outlined above related to LNG and Economic Development costs, Advertising and Marketing expenses, Rate Case costs and TIMP Pipeline Reassessment and Risk Analysis costs, I am also recommending adjustments to several of the other incremental Projected Future Test Year costs included in the Company's claim, including $300,000 in additional engineering services and $50,000 in additional engineering training. I am also proposing an amortization for the $811,166 in operating costs associated with the implementation of a new Asset Management Work system. These adjustments are shown in Exhibit ACC-2, Schedule 19.

Q. What is the basis for your recommendation to exclude $300,000 in additional engineering services and $50,000 in additional engineering training from the Company's revenue requirement?

A. The Company indicated that the $300,000 in additional engineering services was required "to eliminate the exemption for Professional Engineers to sign off on designs and construction drawings. Not all of this cost will be capitalizable." However, the Company provided no additional details regarding how the $300,000 was determined and how much, if any, of the $300,000 would be capitalized. It also included $50,000 for additional engineering training; however, there is no suggestion that current engineering training practices are inadequate or how this additional $50,000 would be utilized. Given the subjective nature of using a fully forecast Future Test Year based on budgeted data, the Commission should be especially vigilant to guard against claims for incremental costs that are not adequately supported by the utility.

Q. Finally, please discuss your adjustment to the Company's claim associated with the new Work Asset Management system.

A. The Company has included $811,166 associated with this new Work Asset Management System, representing implementation costs that cannot be capitalized. However, since the asset management system is expected to last for many years, it would be inappropriate to recover these implementation costs over one year. Therefore, at Exhibit ACC-2, Schedule 18, I have made an adjustment to reflect a five-year recovery for these costs, consistent with the recovery periods that I have used for several other expenditures in this case. My adjustment to reflect a five-year recovery period for these costs results in an adjustment of $648,933 to the Company's cost claim of $811,166.

Q. What is the total adjustment that you are recommending for the engineering services, engineering training, and Work Asset Management implementation costs discussed above?

A. These adjustments total $998,933 as shown in Exhibit ACC-2, Schedule 19.

H. Depreciation Expense

Q. How did the Company develop its depreciation expense claim in this case?

A. On June 8, 2020, the Company filed a Petition in Docket No. 20200166 requesting that the PSC authorize new depreciation rates effective January 1, 2021. The Company estimates that the new rates will increase its pro forma annual depreciation expense by

$3.7 million, as referenced on page 21 of Sean Hillary's testimony. The PSC subsequently consolidated the Depreciation Docket and this base rate case. The Company's requested depreciation rates were applied to projected gross plant balances, by month, to determine the projected Future Test Year depreciation expense.

Q. Are you recommending any adjustment to the Company's depreciation rates or pro forma depreciation expense claims?

A. Yes, I am recommending two adjustments. First, since I am recommending that the Company's rate base reflect utility plant as of December 31, 2020, it is necessary to make an adjustment to depreciation expense to synchronize this expense with my recommended utility plant balances. To quantify my adjustment, I annualized the Company's January 2021 projected depreciation expense, which reflects plant balances through December 2020. My adjustment is shown in Exhibit ACC-2, Schedule 20.

Q. Please describe your second adjustment to the Company's depreciation expense claim.

A. OPC witness David Garrett is recommending adjustments to several of the depreciation rates proposed by the Company in its depreciation study. At Exhibit ACC- 2, Schedule 21, I have made an adjustment to reflect the depreciation rates proposed by Mr. Garrett, applied to the December 31, 2020, plant balances that I have included in my rate base recommendation.

<u>I. Property Tax Expense</u>

Q. How did the Company determine its claim for property tax expense?

A. As discussed by PGS witness Sean Hillary on page 18, PGS' property tax claim is based on forecasted tax rates and projected assessed values during the Projected Test Year.

Q. Are you recommending any adjustment to the Company's property tax expense claim?

A. I am not recommending any adjustment to the property tax rates proposed by PGS. However, consistent with my recommendation that net plant should reflect projected balances at December 31, 2020, I am recommending the PSC base its pro forma property tax allowance on plant balances as of December 31, 2020. Since property taxes are determined based on assessed values, and not on book values, I quantified my adjustment by first determining the overall percentage reduction to gross plant that I am recommending in this case. My recommendations reduce the Company's gross plant claim by approximately 3.47%. I assumed that the reduction to assessed values would be proportional to my recommended gross plant reduction. Therefore, at Exhibit ACC-2, Schedule 22, I have made an adjustment to reduce the Company's Projected Test Year property tax expense by 3.47%.

J. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Exhibit ACC-2, Schedule 23. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Garrett. The rate base and cost of capital being recommended by the OPC in this case result in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under our recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Exhibit ACC-2, Schedule 24, I have used a composite income tax factor of 24.52%, which includes a state income tax rate of 4.46% and a federal income tax rate of 21%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Exhibit ACC-2, Schedule 25, incorporates these tax rates. In addition, the revenue multiplier also includes the regulatory assessment of 0.5% and PGS' claimed uncollectible rate of 0.3423%. This results in a revenue multiplier of 1.3361.

Q. Are you also recommending that the Commission adopt a parent company interest adjustment?

A. Yes, I am. As discussed on page 24 of Ms. Strickland's testimony, Rule 25-14.004, F.A.C., Effect of Parent Debt on Federal Corporate Income Tax, provides that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." PGS does participate in the filing of a consolidated income tax return. Nevertheless, PGS did not include a parent company interest adjustment in its filing.

Q. Why didn't PGS include a parent company interest adjustment?

A. Ms. Strickland states on page 25 of her testimony that she did not include a parent company adjustment because "For the 2021 projected test year, EUSHI [Emera U.S. Holdings, Inc.] will not have any debt on its balance sheet for which it will claim any interest expense deductions on its U.S. consolidated income tax return." Ms. Strickland goes on to state that while in the past EUSHI has had a number of interest-bearing loans from U.S. affiliates, Emera has now centralized the intercompany financing activities into one main financing entity owned by EUSHI."

Q. Why do you recommend that that the Commission require PGS to include a parent company interest adjustment in its revenue requirement?

A. I recommend that the Commission require a parent company interest adjustment because the filing of a consolidated income tax return conveys huge tax advantages that are not otherwise being reflected in regulated utility rates. PGS files a consolidated income tax return as part of the EUSHI consolidated income tax group. In this case, the Company is seeking to recover over $20 million of federal income tax expense annually from Florida ratepayers. However, as stated in the response to OPC IRR-36, EUSHI "did not make any payments to the IRS in each of the past three years." In addition, PGS has net operating tax loss carry-forwards of $15.9 million and is expected to generate additional federal tax losses of $36.8 million through the Future Test Year. Therefore, there is a major disconnect between the statutory income tax rates used to calculate federal income taxes for ratemaking purposes and the actual taxes being paid by the consolidated income tax group.

Q. Did you quantify a parent company interest adjustment?

A. No, I have not. Staff requested that the Company provide such an adjustment in Staff IRR-37, to which the Company has not yet responded. In this request, Staff requested that the Company revise "MFR Schedule C-26 using Emera Incorporated as the parent of PGS, including a parent debt adjustment in row 10." I recommend that the Commission include a parent company adjustment for PGS in its revenue requirement determination based on the Company's response to this interrogatory. While EUSHI may not be projected to have long-term debt, due to creative restructuring, that should not rob PGS' ratepayers of certain tax benefits that the Florida Legislature determined should presumptively be reflected in regulated rates. Therefore, my revenue requirement recommendation should be updated once this response is received from PGS.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in your testimony?

A. My adjustments indicate a revenue deficiency at present rates of no more than $42,221,562, as summarized on Exhibit ACC-2, Schedule 1. This recommendation reflects revenue requirement adjustments of $42,103,332 to the Company's claimed revenue deficiency of $85,324,894. My recommendations would result in a base revenue increase of no more than approximately 17.2%. The actual rate impact on ratepayers will be significantly less, since my recommended revenue increase reflects the impact of rolling-in to base rates certain costs that would otherwise be collected through the CI/BSR. Assuming that the CI/BSR would cost ratepayers $23,608,583 annually, as quantified by PGS, my recommendations would result in a net revenue increase of no more than approximately $18,612,979 or approximately 6.9%. In addition, I recommend that the Commission adopt a further adjustment to reflect a parent company interest adjustment, as discussed above.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Exhibit ACC-2, Schedule 26, I have quantified the revenue requirement impact of each of the rate of return, rate base, and expense recommendations contained in this testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Intesar Terkawi was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 20200051-GU

AUGUST 31, 2020

Q. Please state your name and business address.

A. My name is Intesar Terkawi. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

A. I am employed by the Florida Public Service Commission (Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since October 2001.

Q. Briefly review your educational and professional background.

A. In 1995, I received a Master of Arts Degree with a major in Communications from the University of Central Florida. In 2001, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Public Accountant.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utility Analyst with the responsibilities of managing regulated utility financial audits. I am also responsible for creating audit work programs to meet a specific audit purpose.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 20140001-EI, 20150001-EI, 20160001-EI, 20170001-EI, 20180001-EI, and 20190001-

EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Peoples Gas System (PGS or Utility) which addresses the Utility's filing in Docket No. 20200051-GU, Petition for Rate Increase by Peoples Gas System. We issued an auditor's report in this docket on August 31, 2020. This report is filed with my testimony and is identified as Exhibit IT-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me or under my direction.

Q. Please describe the work you performed in this audit?

A. The procedures that we performed in this audit are listed in the Objectives and Procedures section of the attached Exhibit IT-1, pages 4 through 8.

Q. Please review the audit findings in this audit report.

A. There were 2 audit findings reported in this audit and are found in the attached Exhibit IT-1, pages 9 and 10. They are summarized below.

Finding 1: Association Dues and Economic Development Expenses

2019 Operation and Maintenance expenses should be reduced by $25,000. The projected test year expenses for 2021 should be reduced by $26,112. The Utility stated to us that "the Associated Gas Distributors of Florida ('AGDF') also engages in lobbying activities and advises the Company that a portion of the dues are for lobbying purposes on the invoice." In the 2019 base year, the portion of AGDF dues related to lobbying was $50,000.

Through its review the Utility has found that $25,000 was directly charged to FERC Account 426, a "below the line" account (an account not included in calculating regulatory recovery) and the other $25,000 was charged to FERC Account 930.2. The $25,000 in FERC account 930.2 was included in the 2019 base year data on MFR Schedule G-2, page 18 and was trended forward at 2.2% inflation to the projected 2021 test year O&M, resulting in $26,112.

Finding 2: Advertising Expenses

The analyst should consider removing $88,453 from 2019 Advertising expenses. In addition, $605 should be reclassified to Account 930.2-Miscellaneous General Expenses.

The individual amounts, along with the justification for removing them, are as follows:

- $13,650 from Northeast Florida builders Association, invoice #18953, which represents a non-utility sponsored event featuring food and a golf tournament.
- $7,500 from Tampa Bay Builders Association Inc., which represents a non-utility sponsored event.
- $1,500 from Kiwanis Club of Inverness, which represents a non-utility sponsored event.
- $426 from Kiwanis Club of Inverness, which represents a non-utility sponsored event.
- $680 from Business Wire, which represents an image-enhancing advertisement celebrating new customers with prize-gifts, and is non-utility in nature.
- $470 from Business Wire, which represents an image-enhancing advertisement, and is non-utility in nature.
- $580 from Business Wire, which represents an advertisement related to Hurricane Dorian.
- $450 from Brandmark, which represents an advertisement related to Hurricane Preparedness.
- $63,000 from Sparks Research that is a "Customer Retention Study," not an advertising expense.
- $197 is a late payment to Data Publishing.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Rhonda L. Hicks was inserted.)

DIRECT TESTIMONY OF RHONDA L. HICKS

Q. Please state your name and address.

A. My name is Rhonda L. Hicks. My address is 2540 Shumard Oak Boulevard; Tallahassee, Florida; 32399-0850.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as Chief of the Bureau of Consumer Assistance in the Office of Consumer Assistance & Outreach.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from Florida A&M University in 1986 with a Bachelor of Science degree in Accounting. I have worked for the Commission for more than 34 years, and I have varied experience in the electric, gas, telephone, and water and wastewater industries. My work experience includes rate cases, cost recovery clauses, depreciation studies, tax, audit, consumer outreach, and consumer complaints. During the course of my career at the Commission, I have testified in numerous dockets involving varied industries regulated by the Commission. I currently work in the Bureau of Consumer Assistance within the Office of Consumer Assistance & Outreach where I manage consumer complaints and inquiries.

Q. What is the function of the Bureau of Consumer Assistance?

A. The Bureau's function is to resolve disputes between regulated companies and their customers as quickly, effectively, and inexpensively as possible.

Q. Do all consumers that have a dispute with their regulated company contact the Bureau of Consumer Assistance?

A. No. Consumers may initially file their complaint with the regulated company and reach a resolution without the Bureau's intervention. In fact, consumers are encouraged to allow the regulated company the opportunity to resolve the dispute prior to any Commission involvement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss/outline the number of consumer complaints logged with the Commission against Peoples Gas Company under Rule 25-22.032, Florida Administrative Code, Consumer Complaints, from August 27, 2015, through August 27, 2020. My testimony will also provide information on the type of complaints logged and those complaints that appear to be rule violations.

Q. What do your records indicate concerning the number of complaints logged against Peoples Gas Company?

A. From August 27, 2015, through August 27, 2020, the Commission logged 462 complaints against Peoples Gas Company. Of those, 259 complaints were transferred directly to the company for resolution via the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to Peoples Gas Company's customer service personnel. Once the call is transferred to Peoples Gas Company, the Company can provide the customer with a proposed resolution.

Q. What have been the most common types of complaints logged against Peoples Gas Company during the period August 27, 2015, through August 27, 2020?

A. During the specified time period, approximately forty-seven (47%) percent of the complaints logged with the Commission concerned billing issues, while approximately fifty-three (53%) percent of the complaints involved quality of service issues.

Q. Do you have any exhibits attached to your testimony?

A. Yes. I am sponsoring Exhibits RLH-1 and RLH-2, which are listings of customer complaints logged with the Commission against Peoples Gas Company under Rule 25-22.032, Florida Administrative Code. The complaints listed were received between August 27, 2015, through August 27, 2020, and were captured in the Commission's Consumer Activity Tracking System (CATS). Exhibit RLH-1 lists quality of service complaints and Exhibit RLH-2 lists billing complaints. Both exhibits group the complaints by Close Type.

Q. What is a Close Type?

A. A Close Type is an internal categorization code. It is assigned to each complaint once staff completes its investigation, and a proposed resolution is provided to the consumer.

Q. Do you have any additional exhibits?

A. Yes. Exhibit RLH-3 is a listing of complaints resolved as Close Type GI-02, Courtesy Call/Warm Transfer.

Q. Can you explain Close Type GI-02?

A. Yes. Peoples Gas Company participates in the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to the company's customer service personnel. Once the call is transferred to Peoples Gas Company, it provides the customer with a proposed resolution. Customers who are not satisfied with the company's proposed resolution have the option of recontacting the Commission. While the Commission is able to categorize each of the complaints in the GI-02 category, a specific Close Type is not assigned because the proposed resolution is provided by Peoples Gas Company. Consequently, the GI-02 Close Type only allows staff to monitor the number of complaints resolved via the Commission's Transfer-Connect System.

Q. How many of the complaints summarized on your exhibit has staff determined may be a violation of Commission rules?

A. Staff determined that, of the 462 complaints logged against Peoples Gas Company during the period August 27, 2015, through August 27, 2020, none of those complaints appear to demonstrate a violation of Commission rules.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled rebuttal testimony of Richard F. Wall was inserted.)

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

RICHARD F. WALL

Q. Please state your name, business address, occupation, and employer.

A. My name is Richard F. Wall. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Peoples Gas System ("Peoples" or the "Company").

Q. Are you the same Richard F. Wall who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address serious errors and shortcomings in the prepared direct testimony of witness Andrea C. Crane, testifying on behalf of the Office of Public Counsel ("OPC").

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. No, I have not.

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Crane's testimony.

A. My key concerns and disagreements are as follows:

1. I disagree with witness Crane’s unwarranted removal of the 2021 plant-in-service and construction work in progress (“CWIP”) net additions from the Company’s 2021 rate base.
2. I disagree with witness Crane’s assertion that there will likely be significant delays in project construction because of the COVID-19 pandemic which would reduce plant-in-service rate base.
3. I disagree with witness Crane’s assertion that the capital costs are inflated to reflect enhancements in Peoples’ system to allow for future Liquified Natural Gas (“LNG”) service.
4. I disagree with witness Crane’s unsupportable recommendation to reduce by $350,000 the Company’s budget for incremental engineering services and

training expenses; and,

5. I disagree with witness Crane’s recommendation to remove all new employee resources from the 2021 budget. In, addition, I disagree with witness Crane’s conclusion that $163,200 in operation employees’ expenses and materials costs should be disallowed.

1. Plant In Service And CWIP For 2021 Additions

Q. Do you agree with witness Crane’s argument on pages 10-16 of her testimony that the 2021 net capital additions should be removed from the Company’s rate base?

A. No, I do not agree.

Q. Why not?

A. As discussed in my direct testimony and the testimony of Company witness Sean P. Hillary, Peoples’ capital requirements are determined through a rigorous budgetary process with detailed reviews which occur at various levels throughout the Company, including the Board of Directors. This process ensures that Peoples’ capital allocation is made on projects which are necessary to improve system reliability, enhance operating safety and/or allow Peoples to reasonably meet future customer growth. Witness Crane's removal of the 2021 net plant-in-service and CWIP additions is completely arbitrary and contains no analysis of the merits and/or need of any individual project.

My direct testimony, and Peoples' responses to interrogatories on the status of the individual projects listed in the capital budget, have shown that there is a supportable need for these sustaining, municipal improvement, growth (mains and services), etc. projects. Witness Crane has not provided any evidence that these projects are not needed, but rather simply asserts that the spend should be less.

Q. Do you agree with witness Crane's conclusions that Peoples' capital growth during the 2020 – 2021 period is ambitious and therefore requires a downward adjustment?

A. No, I do not agree. Witness Crane's conclusions completely ignore the Company's need to invest in its natural gas distribution systems to enable operational safety and reliability, and in customer based main and services related expansion, including:

1. The capital spending is needed to respond to

Peoples’ increasing number of customers which will continue into 2021. Witness Crane does not offer any evidence that Peoples will not continue to add customers or will not have to continue to maintain and improve its systems.

2 The capital spending is required to support Peoples’ system reliability and safety needs which will continue to grow into 2021 for reasons stated in my original testimony. Again, witness Crane offers only conclusory speculation, rather than evidence, to suggest the spending needs for safety and reliability are not required.

3 Witness Crane’s assertion that COVID-19 will delay construction projects is without evidence and is simply not true.

Q. Do you agree with witness Crane that construction delays will be caused by COVID-19?

A. No, I do not agree.

Q. Why not?

A. There is no indication that COVID-19 has been an impediment to the pace of construction. In fact, housing construction around the state has remained steady, including the consistent flow of service requests for the installation of residential service lines in each of the contracted residential developments. From March 2020, the beginning of the COVID-19 epidemic, the Company has been able to successfully maintain engineering and design services, construction materials, and construction contractor crews to meet the Company’s construction needs. Natural gas service and the construction to serve Peoples’ customer’s energy needs is considered an essential service which means that there have been no government-imposed halts in construction. And, because natural gas pipeline construction workers do not generally need to be in close contact with one another, or with customers, social distance restrictions can be easily met while continuing to adhere to a normal construction schedules and the related pipeline construction and installation practices.

Q. Have there been significant delays in the 2020 and 2021 capital budget projects?

A. No, there have not been any significant delays in the construction schedule. There have been projects which have been cancelled or deferred and these, along with the reasons for the cancellation, are identified in Peoples' response to Staff's Seventh Request for Production of Documents No. 15a.

Some projects have temporarily been placed on hold because of changes in Company priorities, such as the Miami office building. The Company does not consider these to be construction delays. These projects have been replaced by other priority projects as discussed in witness Hillary's rebuttal testimony and the Company's revised capital budget for 2020 and 2021 as presented in response to Staff's Seventh Request for Production of Documents No. 15a.

Generally, delays that have occurred have been minor and the result of typical project logistics and normal coordination issues such as extended permit wait times or more onerous permit conditions, adverse weather, awaiting service agreements to be signed by customers or awaiting for activities to be completed that are outside the Company's control, such as coordinating pipeline installations involving roadway construction that depends on multiple utility/agency (Water/Sewer, Power, Telecom, Drainage, etc.) infrastructure placement related coordination, and the associated needs of differing construction projects and crews.

Q. Witness Crane states on page 11 of her testimony that a portion of the Southwest Florida project is now projected to be delayed until March 2021. Is this correct?

A. No, this is not correct. In fact, the Southwest Florida main is substantially complete and currently in the final testing and activation phase. The project is ahead of schedule and the Company anticipates it will be completed and in service by the end of September 2020.

Q. Do you agree with witness Crane's conclusion that Peoples will not be able to meet its construction schedule?

A. No, I do not agree. Construction is frequently performed by external subcontractors working under established agreements (blanket contracts and specific large project bid/awarded contracts) and as a result Peoples can execute its increased capital spending program by expanding and flexing its workforce through contract service for additional engineering, project management and construction services. Peoples has a solid track record in both its construction management and in ensuring timely and effective construction performance in the completion of its capital projects. Peoples ensures project performance through the quality of the Company’s project management team, and adherence to design, safety, and overall craftsmanship and by meeting construction objectives and targeted deadlines.

There is no reason to expect that Peoples will not be able to complete the construction requirements of the projects currently provided in the 2020/21 capital budget. Peoples is on track with respect to its construction schedule, the details of which are provided in Peoples’ response to Staff’s Seventh Request for Production of Documents No. 15a.

Q. Is it normal practice for Peoples to modify its capital budget during the year?

A. Yes, it is normal practice for the capital budget to be modified throughout the year to give effect to increased project work performance and/or delays which arise due to permitting, changes in the customer’s priorities, and to reflect new projects which come up during the year which were not previously considered in the capital budgeting process. The construction schedule is fluid and some projects are completed earlier than expected while others are completed later.

Q. Are you confident that the sustaining projects contained in the updated capital budget and the capital reforecast provided in the Company's response to Staff's Seventh Request for Production of Documents No. 15a are prudent?

A. I am confident that the sustaining projects reflected in the capital budget and the capital reforecast as presented in the Company's response are prudent, reasonable, and necessary for the efficient, safe, and reliable operation of Peoples' natural gas business.

2. Engineering Services And Training Expenses

Q. Do you agree with witness Crane that the $350,000 of engineering services and the $50,000 of training costs should be removed from the Company's filing?

A. No, I do not agree. These engineering and training expenses are intended to proactively address risk mitigation and specific lessons learned from operating failures and associated gas leaks and subsequent explosions in Merrimack Valley, Massachusetts. As a result of the Merrimack Valley incident, there has been increased emphasis on requiring a higher level of engineering oversight on projects.

These efforts and the related expenses are a part of the Company’s ongoing overall improvement plans to properly prepare for additional increasing regulatory and safety related performance expectations/requirements. The results of this effort are also expected to require the Company to have Professional Engineer (“PE”) resources who will directly review, sign and seal construction design drawings and plans and, provide pre-construction procedural reviews of the steps and requirements for the introduction of natural gas into the pipeline.

Witness Crane simply ignores the necessity of spending money on these activities in order to prevent similar occurrences on Peoples’ system.

Q. How was the $300,000 of engineering services determined?

A. The $300,000 engineering services expense is to provide for an external review of the Company’s processes as a result of recent events in the Merrimack Valley. Peoples’ has currently engaged an external resource to review the Company’s current processes and procedures; to provide recommendations of additional processes to mitigate the risk and specific programs and process improvements to be implemented. These efforts and the related expenses are a part of the Company's overall improvement plans to properly prepare for increasing regulatory and safety related performance expectations.

Q. What will be the focus of the external review?

A. The external consultant will focus on the following:

1. Complete a review of Peoples' current internal engineering design practices, including the review of the types of work activity done by Company engineers to identify areas where technical improvements could be made; a review of the Company's specific technical processes to benchmark against industry best practices; and, a review of Peoples' workflow to ensure proper design oversight and sign off is provided for major projects that may require PE sign off in the future.
2. Complete a review of the Company's engineering standards and identify areas of improvements; to benchmark key Company standards with industry best practices; to identify additional engineering standards that may be necessary; and, to review

Company protocols that ensure standards are current and adequately reviewed on a regular basis.

3. To review the Company's construction standards and identify areas of improvements; to benchmark these key construction standards with industry best practices; to identify key construction activities and practices that may require a higher level of technical oversight or PE review and sign off; and to review protocol for ensuring construction standards are current and adequately reviewed on a regular basis.

Q. What are the training services of $50,000 for and what supports the need for these to be included in the rate case submission?

A. As part of the Company's efforts to improve the technical competencies of designers and engineers the Company plans to incorporate a structured technical training program for all engineering technicians and designers moving forward. In 2021 the Company plans to retain and utilize the Gas Technology Institute ("GTI") to conduct multiple onsite training workshops covering gas transmission, distribution and measurement and regulator design, regulatory requirements, and safety considerations.

3. LNG Service

Q. Do you agree with witness Crane's assertion that the capital costs presented in the rate case filing are inflated to reflect enhancements in Peoples' system to allow for the provision of LNG?

A. No, I do not agree.

Q. Why not?

A. On page 17 line 21 of witness Crane's testimony she states

> "my adjustment to include no more than the December 31, 2020 plant-in-service balance in the required revenue requirement also recognizes the Company has not demonstrated that the overall level of additions to transmission and distribution facilities are adequately allocated to any demand placed on the system by the Company's planned entry into the facilities-based competitive provision of LNG services under the proposed tariff."

This suggestion is to remove all 2021 capital expenditures from the revenue requirement calculation is careless and completely unsubstantiated. None of Peoples' capital expenditures within the 2020 or 2021 capital budget or reforecast are necessitated by the proposed LNG tariff.

4. <u>Employee Resources</u>

Q. Do you agree with witness Crane's recommendation to disallow the $4.3 million in new employee positions?

A. No, I do not agree. Peoples' response to OPC's First Set of Interrogatories No. 50 provided a position by position description of positions budgeted to be added in 2020 and 2021, the start month/year, and the O&M related payroll cost for each year. In addition, the response provided a need explanation for each of the unfilled positions and indicated the positions that had been filled at the time of the response. As discussed by witness Hillary on pages 13 -14 of his rebuttal testimony the $4.3 million should be reduced by $1.4 million for the positions which have been filled, resulting in a net amount of $2.9 million. Included in the $2.9 million are 31 new hires in the areas of gas operations, pipeline safety and pipeline operations compliance responsibilities, all of which are roles necessary to support Peoples' operations and to maintain system safety and reliability.

Q. Please explain why there are unfilled positions in the gas operations, pipeline safety and pipeline operations compliance responsibilities.

A. Due to unplanned 2020 earnings challenges plus the very specific restrictions and initial difficulties onboarding and training new hires due to the pandemic, the Company has temporarily held off filling some of the 2020 budgeted positions reflected in the Company's response to OPC's First Set of Interrogatories No. 50.

Q. Please explain the purpose, and general responsibilities for these 2020 and 2021 new employee positions.

A. As provided in Peoples' response to OPC's First Set of Interrogatories No. 50 these employee positions are needed to effectively, efficiently and safely manage Peoples operating system by providing the staffing needed in order to perform customer service and billing, field service, emergency response, engineering and construction, inspection, 811 one-call, maintenance, compliance and safety related responsibilities.

Q. What is the need for the additional $163,200 of Operations Employee expenses and Materials costs for additional staffing in the 2021 test year?

A. As Peoples expands the staffing of its operational teams, it is necessary to add employee expenses to support their annual activities. These staff positions incur employee expenses related to tools & equipment, uniforms, training and travel, and other incidental expenses. The increase of $163,200 is to adequately provide for the expansive territory being served by critical resources that are dedicated to operating these natural gas systems and pipelines, and safely serving Peoples' customers, and the general public in each of the Company's 14 service areas.

Witness Crane's recommendation to eliminate these expenses on pages 26 – 27 of her testimony ignores their necessity.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. I have identified and addressed a number of serious errors and shortcomings in the testimony of witness Crane. She repeatedly and inaccurately identified specific reductions and disallowances without citing specific facts, supporting information and or quantitative basis for her positions. I have presented facts and information that accurately identifies and supports the Company’s petition and its plans, active programs, and ongoing performance results.

In summary, I have shown that the removal of the 2021 plant-in-service and CWIP net additions from the Company’s 2021 rate base is unwarranted; that there have not been significant delays in Peoples’ project construction schedule as a result of the COVID-19 pandemic; that the capital costs are not inflated to reflect enhancements in Peoples’ system to allow for future LNG service; that the incremental engineering services and training expenses of $350,000 are necessary and needed; that the new employee additions for 2020 and 2021 are necessary and needed to ensure system safety and reliability; and that the $163,200 in Operation Employees expenses and materials costs should not be disallowed as recommended by witness Crane.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

(Whereupon, prefiled rebuttal testimony of Timothy O'Connor was inserted.)

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

TIMOTHY O'CONNOR

Q. Please state your name, business address, occupation and employer.

A. My name is Timothy O'Connor. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Peoples Gas System ("Peoples" or the "Company") as Vice President, Business Development.

Q. Are you the same Timothy O'Connor who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to correct certain positions taken in the prepared direct testimony of witness Andrea Crane, hired by the Office of Public Counsel ("OPC"), and testifying on behalf of the Citizens of the State of Florida with which I have concern.

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. No, I have not.

Q. Please summarize your areas of disagreement with witness Crane's testimony.

A. My key disagreements are as follows:

1. Witness Crane ignores the Company's need for capital expenditures to meet customer demand.
2. Witness Crane mischaracterizes the LNG Tariff and the use of LNG on Peoples' system.
3. Witness Crane ignores the Company's need to support economic development efforts.
4. Contrary to Witness Crane's opinion to not allow recovery for any new hires, increased customer demand is driving an increased need for additional employees for the Company's Compressed Natural Gas (CNG), Liquified Natural Gas ("LNG"), and Renewable Natural Gas ("RNG") business.

1. <u>Reduction To Distribution Plant Rate Base</u>

Q. Please explain why you disagree with Witness Crane's proposed adjustment to capital expenditures.

A. Witness Crane bases her proposed adjustment on the fact that she believes Peoples' increases in its capital spend are "speculative" projections presented on page 12, line 5, and characterizes the growth in capital spending as "explosive" presented on page 8, line 16 which suggests that growth beyond a certain unnamed amount should not be considered by the Commission. Witness Crane's testimony ignores the fact that these capital expenditures are necessary, in part, to respond to existing system reliability and capacity needs and/or near-term capacity needs of system growth resulting from increased customer demand. Other capital expenditures are needed for safety and reliability as outlined in the direct and rebuttal testimony of other Company witnesses. Since Peoples' last rate case in 2008, Florida's population has grown substantially which has helped fuel Company growth during this period. Witness Crane simply ignores the overwhelming evidence that has been presented of the tremendous customer demand and growth that the Company has been experiencing. Peoples' infrastructure has expanded to accommodate this very real growth in demand. While Witness Crane characterizes this growth as "explosive," she offers no evidence that it is not real. The Company's new residential and commercial business signings have consistently grown requiring the Company to steadily increase its capital expenditures to meet this growing demand for safe, affordable, and reliable natural gas. These new customers come online over many years and these customer commitments are incorporated into planned 2021 and future years' capital expenditures.

Q. Are the capital projects undertaken by Peoples intended to expand into speculative activities or to enter competitive markets as witness Crane suggests on page 10, lines 11-17 of her testimony?

A. No. Witness Crane suggests Peoples activities are speculative with no supporting facts. The fact is that Peoples' capital projects are not speculative as evidenced by the Company's strong customer growth rates and system needs. These projects are necessary for the continued provision of safe and reliable regulated gas service. Moreover, Peoples participates in a competitive market every day because gas is a choice in Florida. Witness Crane references the LNG market related to competitive markets. Peoples has proposed an LNG tariff, but the 2021 capital expenditures do not include any capital under this proposed tariff.

Q. Do you have any other comments regarding Witness Crane's testimony regarding capital expenditures?

A. As provided in my original testimony, Peoples has experienced an approximate 23 percent increase in customers served since 2007. In the last two years, customer growth has increased approximately 3.5 percent per year. As presented in Company witness Sean P. Hillary's rebuttal testimony, between July 2019 and July 2020, Peoples is experiencing customer growth of approximately five percent. The capital expenditures in Peoples' rate filing reflect the need to meet this customer demand. Witness Crane's testimony fails to provide any supporting data for her adjustment in capital expenditures and ignores Peoples' actual growth experience. Customers want natural gas. They like its affordability and the environmental benefits. Customers desire Peoples to provide this service as evidenced by the Company's number one ranking in J.D. Powers Residential Customer Satisfaction Studies in customer satisfaction for many consecutive years.

2. <u>Mischaracterization Of The Proposed LNG Tariff And Miami LNG Project</u>

Q. Does the Miami LNG Project differ from what Peoples proposed in its LNG tariff?

A. Yes. The Miami LNG project is a peak-shaving storage and regasification facility to address a system capacity need in Peoples' Miami division. Since this project is solely for internal system needs, the proposed LNG tariff would not be applicable. Peoples does not need a tariff to design, construct and operate its own LNG storage facility such as the Miami LNG facility. Peoples proposed LNG tariff would allow Peoples to offer the option of LNG services to specific customers. The Miami LNG facility will not be used for that purpose.

Q. Can the Miami LNG project be used to serve third party customers such as cruise ships as Witness Crane suggests in her testimony?

A. No. Again, the Miami LNG project is designed to only serve Peoples' distribution system. Witness Crane's hypothetical presented on page 17, lines 16-20, is not possible given the size and design of the Miami LNG project, the fact that the project location is landlocked and ignores the fact that the Port of Miami does not currently have LNG infrastructure to receive LNG or supply LNG to cruise ships. Witness Crane's hypothetical is unrealistic because the expense and complexity of building an LNG pipeline to transport LNG from a landlocked location through a highly urban area to the Port of Miami would be economically unfeasible.

Q. Do you have any other comments regarding Witness Crane's testimony regarding LNG?

A. Witness Crane's testimony regarding Peoples Miami LNG project is based on a misunderstanding of the system need that necessitates the project as well as a misunderstanding of how the project will be designed to meet that system need. Witness Crane's testimony presented on page 17, lines 7-20 is further confused by referencing a separate docket for a proposed LNG services tariff, which is in no way connected to the Miami LNG project.

3. <u>Need to support economic development efforts in Florida</u>

Q. Do you agree with Witness Crane's recommendation on page 33, line 16 to deny increased Peoples' employee and associated expenditures related to Economic Development activities within the areas served by Peoples.

A. No. It is well understood that utilities are critical elements for economic development throughout Florida. Natural gas provides affordable, reliable, and safe energy that supports economic development for customers and businesses. The increased expenditures related to economic development, which are recoverable pursuant to FPSC Rule 25-7.042, enhance and support many facets of economic development in the major metropolitan and rural areas served by Peoples Gas. We support the economic vitality of Florida through funding these economic development activities that improve the quality of life for all Floridians including support to small and minority-owned businesses, attracting new jobs and businesses to Florida, and promoting Florida's goods and services.

4. Witness Crane's Denial Of New Employees Presented On Page 22, Lines 3-17 Based On The Company's LNG And RNG Needs.

Q. Please provide an overview of the additional employee requirements for Business Development.

A. In Peoples' response to OPC's First Set of Interrogatories No. 50, the a position by position description for all positions Peoples' budgeted to be added in 2020 and 2021, the start month/year, and the O&M related payroll cost for each year. In addition, the response provided an explanation of need for each of the 2020 unfilled positions and new 2021 budgeted positions. Over fifty positions make up the total of $4.3 million for these new positions. Company witness Richard F. Wall's and witness Hillary's rebuttal testimonies will provide further support for most of these positions. Business Development plans to add fourteen new employees. I will summarize the reasons for the added employees as follows:

1. Addition of new expertise given developing market conditions with RNG and applications for LNG.
2. Additional resources to support customer growth and add data and analytical capabilities.

Q. Please describe the expertise needs for RNG.

A. RNG are projects that condition biogas from landfills, wastewater treatment plants and farms to pipeline quality for injection into the pipeline system. Experience and expertise with such projects are different than traditional pipeline business development backgrounds. Peoples' currently only has one employee with RNG experience. New employee additions include three new employees which are necessary to adequately support the interest for RNG projects throughout Florida.

Q. Please describe the expertise needs for LNG.

A. LNG storage and regasification can provide a cost-effective solution as compared to pipeline alternatives. Peoples currently has one employee dedicated to LNG business development and does not have staff with experience in operation and maintenance of such facilities and will therefore add two new employees to provide expertise to Peoples so that it is better able to investigate and use LNG storage to enhance its system. Furthermore, customers are increasingly contacting Peoples regarding potential LNG solutions, and to support this interest and demand, People will add two employees to work with potential new customers and proposed LNG solutions. Given the opportunity for Florida businesses to utilize LNG, Peoples will need experienced LNG personnel to meet this need.

Q. Please describe the incremental employees needed to support customer growth and for added data and analytical capabilities.

A. In the past, Peoples did not have employees focused on data management and analytics in support of customer growth. As the Company has grown and the range of business offerings has increased, Peoples has created an analytics group that captures, aggregates, and analyzes data. These increased capabilities require employees with these skills sets. The strong customer growth, and with new business segments emerging, the capacity to collect, aggregate and analyze data for informed decision making has significantly increased. Peoples will add six employees to add capacity to handle the volume and complexity of analyses. These analyses will lead to greater customer insights, more predictive decision making, improved data quality and project plans required to meet customer demand. Furthermore, as evidenced by Peoples' actual customer growth, the Company will add one employee to support growing business development activities. This employee will assist in Peoples being as responsive as possible to the growing customer demand for natural gas throughout Florida.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. While citing no substantive information in support, witness Crane suggests a reduction in Peoples' planned capital expenditures, demonstrates a lack of understanding regarding the planned Miami LNG project, ignores the value of economic development in the state of Florida and asserts that Peoples should not hire any new resources to support the fact that the demand of advanced natural gas solutions remains strong. I disagree with all of these opinions.

Furthermore, witness Crane’s suggested adjustments to capital expenditures and employee additions would severely impair Peoples’ ability serve existing and future customers.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 4.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 8th day of December, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024