EXHIBIT NO. ___(RAM-1T)
DOCKET NO. UE-07___/UG-07___
2007 PSE GENERAL RATE CASE
WITNESS: DR. ROGER A. MORIN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-07____** **Docket No. UG-07____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
DR. ROGER A. MORIN
ON BEHALF OF PUGET SOUND ENERGY, INC.

DECEMBER 3, 2007

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(RAM-2).

Q. Have you previously testified on cost of capital before utility regulatory commissions?

A. As a principal in Utility Research International, I regularly serve as a cost of capital witness before regulatory bodies in North America, including the

Washington Utilities and Transportation Commission ("WUTC", or "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. Exhibit No. ___(RAM-2) describes my participation in regulatory proceedings in more detail.

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

A. My testimony presents an independent appraisal of the just, fair, reasonable, and sufficient rate of return on the utility operations of Puget Sound Energy, Inc. ("PSE," or "Company") in the State of Washington, with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on equity ("ROE") that would: (i) be fair to the Company's ratepayers, (ii) allow the Company to attract capital on reasonable terms, (iii) maintain the Company's financial integrity, and (iv) be comparable to returns offered on comparable risk investments.

Q. Please summarize your findings concerning PSE's cost of common equity.

A. I have examined PSE's risks and concluded that PSE's risk environment slightly exceeds the industry average. It is my opinion that a just, fair, reasonable and sufficient ROE for PSE falls in a range between 10.8% and 11.2%.

Q. What methodologies have you employed in arriving at such opinion?

A. My opinion derives from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies.

I performed two CAPM analyses:

(i) a "traditional" CAPM and

(ii) a methodology using an empirical approximation of the CAPM ("ECAPM").

I performed two risk premium analyses:

(i) a historical risk premium analysis on the electric utility industry; and

(ii) a study of the risk premiums reflected in ROEs allowed in the electric utility industry between 1997-2006.

I also performed DCF analyses on three surrogates for the Company's utility business:

(i) Puget Energy, Inc. ("Puget Energy"), PSE's parent company;

(ii) a group of investment-grade dividend-paying integrated electric utilities; and

(iii) a group consisting of the companies that make up Moody's Electric Utility Index.

Q. Have you considered factors other than the above-listed methodologies in

arriving at your recommended ROE?

A. Yes, I would recommend the Commission grant PSE an ROE at the higher end of the 10.8% to 11.2% range to account for the slightly above average risks faced by PSE relative to the industry.

Q. Please describe how your testimony is organized.

A. My testimony consists of five sections. The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. The third section summarizes the results from the various approaches used in determining a fair return and the factors that contribute to the slightly above average risks faced by PSE relative to the industry. The fourth section addresses relevant market circumstances that have changed since the Commission's determination in the Company's last general rate case. The final section contains the conclusion.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

A. Legal and Regulatory Concepts Regarding Rate of Return

Q. Please explain how a regulated company's rates should be set under traditional principles of cost of service regulation.

A. Under the traditional regulatory process, a regulated company's rates should enable the company to recover its costs, including taxes and depreciation, and earn a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained (i.e., investors' return requirements).

Q. What fundamental principles underlie the determination of a fair and reasonable rate of return on common equity?

A. The heart of utility regulation is the setting of just, fair, reasonable and sufficient rates by way of a fair and reasonable ROE. Two landmark U. S. Supreme Court cases define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

(i) *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and

(ii) *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just, fair, reasonable and sufficient rates of return are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public *equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable*, 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 money* necessary for the proper discharge of its public duties.

Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262

U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines for assessing the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> 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 attract capital.

Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The U.S. Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light*, *Gas & Water Division*, 411 U.S. 458 (1973), in *Permian Basin Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. vs. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases,* the Supreme Court stressed that a regulatory agency's rate of return order should

> reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow PSE the opportunity to earn a return on equity that is: (i) commensurate with returns on investments in other firms having corresponding risks, (ii) sufficient to assure confidence in the Company's financial integrity, and (iii) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

B. Economic and Financial Concepts Regarding Rate of Return

Q. How is the fair rate of return determined?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (e.g., bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like PSE enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Utilities and other investor-owned businesses must (i) access capital on the open capital market and (ii) pay a market price for the capital they require (i.e. interest on debt capital and expected return on equity).

Q. How does the concept of a fair return relate to the concept of opportunity cost?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand, and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. What economic and financial concepts have guided your assessment of the Company's cost of common equity?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side and the other to the demand side of capital markets.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments equals, or exceeds, the company's cost of capital. This principle suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital

Q. How does the Company obtain its capital and how is its overall cost of capital determined?

A. The funds employed by the Company are obtained in two general forms--debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual interest payments and preferred dividends. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments.

Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded costs of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital (overall return).

Q. What is the market required rate of return on equity capital?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. What must be considered in estimating a fair ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, to maintain creditworthiness and ability to attract capital on reasonable terms.

The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains (as determined by expected changes in stock prices) and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by investors in the firm is commensurate with the return expected by investors in firms of comparable risk.

Q. How does PSE's cost of capital relate to that of its parent company, Puget Energy?

A. I treat PSE as a separate stand-alone entity, distinct from Puget Energy, because the cost of capital to measure in this proceeding is the cost of capital for PSE and not the cost of capital for Puget Energy's consolidated activities.

Financial theory establishes that the cost of equity is the risk-adjusted opportunity cost to the investor--in this case, Puget Energy. The true cost of capital depends on the use to which the capital is put--in this case PSE's utility operations in the State of Washington. The specific source of funding for an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at an after-tax cost of 8%

and invests the funds in a speculative oil extraction venture, the required return on the investment is not the investor's debt cost of 8% but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on capital invested in PSE is the return foregone in comparable risk utility operations and not the cost of capital of Puget Energy. In other words, the cost of capital is governed by the risk to which the capital is exposed and not by the source of funds.

III. COST OF EQUITY CAPITAL ESTIMATES

A. <u>Three Market-Based Methodologies: CAPM, Risk Premium and DCF</u>

Q. How did you estimate the fair ROE for PSE?

A. I employed three methodologies: (i) the CAPM, (ii) the Risk Premium, and (iii) the DCF methodologies. All three are market-based methodologies and estimate the return required by investors on the common equity capital committed to PSE.

1. <u>Use of More Than One Market-Based Methodology</u>

Q. Why did you use more than one approach for estimating the cost of equity?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

Q. Are there any difficulties in applying cost of capital methodologies in the current utility industry environment?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the utility industry. This is because utility company historical data have become less meaningful for an industry in a state of profound change.

Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including corporate structural transformation and the transition to a more competitive environment. As a result, these historical indicators are not representative of the future long-term earning power of these companies.

Moreover, historical growth rates are not representative of future trends for utilities involved in mergers and acquisitions, as these companies going forward would not be the same companies for which historical data are available.

Q. Are you aware that some regulatory commissions (and some analysts) have placed principal reliance on DCF-based analyses to determine costs of equity for public utilities?

A. Yes, I am.

Q. Do you agree with this approach?

A. While I agree that it is certainly appropriate to consider the results of the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. There are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All of these methodologies are accepted and used by the financial community and supported in the financial literature.

When measuring the cost of common equity, which is essentially the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor.

Absent any hard evidence as to which method outperforms the other, which does not exist as far as I am concerned, all relevant evidence should be used to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. It is unwarranted to conclude that the DCF model, standing alone, is necessarily the ideal or best predictor of the stock price and of the cost of equity reflected in that price, just as it should not be concluded that the CAPM or Risk Premium models, standing alone, produce the perfect or best explanation of that stock price or the cost of equity. As a result, all the various methodologies to estimate the cost of equity should be considered.

Q. Does the financial literature support the use of more than a single method?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Eugene F. Brigham, a widely respected scholar and finance academician, discusses the various methods used in estimating the cost of common equity capital, and states:

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive - no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods....

Eugene F. Brigham & Michael C. Ehrhardt, *Financial Management Theory and Practice* 311 (11th ed. 2005).

Another prominent finance scholar, Professor Stewart Myers, explains that one should

> [use] more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.

Stewart C. Myers, *On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment*, Financial Management 67 (1978).

Q. Does the broad usage of the DCF methodology in past regulatory proceedings indicate that it is superior to other methods?

A. No, uncritical acceptance of the standard DCF equation vests the model with a degree of reliability that is simply not justified. One of the leading experts on public utility regulation, Dr. Charles Phillips, discussed the dangers of relying solely on the DCF model as follows:

> [Use] of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.
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> . . .
>
> [T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model "suggests a degree of precision which is in fact not present" and leaves "wide room for controversy about the level of k [cost of equity]".

Charles F. Phillips, *The Regulation of Public Utilities Theory and Practice* 395-96 (1993) (footnotes omitted).

Dr. Charles F. Phillips also discusses the dangers of relying solely on the CAPM model because of the lack of realism of certain of its stringent assumptions, as is the case for any model in the social sciences.

Sole reliance on any one model, whether DCF, Risk Premium or CAPM, simply ignores the capital market evidence and investors' use of the other theoretical frameworks. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that should supplant other financial theory and market evidence. The same is true of the CAPM.

2. Caution Regarding the DCF Methodology

Q. Do the assumptions underlying the DCF model require that the model be treated with caution?

A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology is problematic for use in estimating the cost of equity for utilities at this time.

Several fundamental structural changes have transformed the energy utility industry since the standard DCF model and its assumptions were developed. For example, increased deregulation, increased wholesale competition triggered by national policy, accounting rule changes, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, improvements in generation efficiencies, highly volatile fuel prices, and mergers-acquisitions have all influenced stock prices in ways that have deviated substantially from the assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation (i.e., price/earnings ratios and market-to-book ratios), are problematic at this particular point in time for utility stocks. Therefore, alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. Is the constant relative market valuation assumption inherent in the DCF model always reasonable?

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion because it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in price-earnings (P/E) and market-to-book (M/B) ratios.

The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes (i) that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings) and (ii) that the stock price will grow at the same rate as the book value. This is a necessary result of the infinite growth assumption inherent in the constant growth DCF model. This assumption is unrealistic under current conditions. The DCF model is not equipped to deal with sudden surges in P/E and M/B ratios, as was experienced by a number of utility stocks in recent years.

In short, caution and judgment are required in interpreting the results of the standard DCF model because of (i) the effect of changes in risk and growth on electric utilities, (ii) the disconnect between the tenets of the DCF model and the characteristics of utility stocks in the current capital market environment, and (iii) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at an ROE recommendation.

3. <u>Caution Regarding the CAPM</u>

Q. Do the assumptions underlying the CAPM require that the model be treated with caution?

A. Yes, as was the case with the DCF model, the assumptions underlying the CAPM are stringent. Moreover, the empirical validity of the CAPM has been the subject of intense research in recent years. Although the CAPM provides useful evidence, it must be complemented by other methodologies.

B. <u>CAPM Estimates</u>

1. <u>Background</u>

Q. Please describe your application of the CAPM risk premium approach.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta.

According to the CAPM, securities are priced such that:

Expected Return = Risk-Free Rate + Risk Premium

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$\mathbf{K = R_F + \beta(R_M - R_F)}$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by β times $(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, $(R_M - R_F)$. For the risk-free rate, I used 5.0%, based on current long-term U.S. Treasury bond yields. For beta, I used 0.92. For the market risk premium, I used 7.1%. These inputs to the CAPM are explained below.

2. <u>Risk-Free Rate</u>

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

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the current and prospective level of yields on 30-year Treasury bonds.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes, for example, 10-year Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, (i.e., yield on 30-year Treasury bonds) is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (e.g., pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. Dr. Morin, why did you reject short-term interest rates as proxies for the risk-free rate in implementing the CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve Board as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes little sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. What is your estimate of the risk-free rate in applying the CAPM?

A. The level of U.S. Treasury 30-year long-term bond yields has fluctuated narrowly around 5% in the past few years and is currently 4.9% as reported by the Value

Line Investment Analyzer in September 2007. Value Line forecasts a slight increase in long-term yields over the next year. Accordingly, I use 5.0% as my estimate of the risk-free rate component of the CAPM.

3. <u>Beta</u>

Q. How did you select the beta for your CAPM analysis?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

As a wholly-owned subsidiary of Puget Energy, PSE is not publicly traded, and therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity below, I examine a sample of widely-traded investment-grade vertically integrated electric utilities that have (i) at least 50% of their revenues from regulated utility operations and (ii) market capitalization was less than $500 million. The average beta for this group is currently 0.92. Please see Exhibit No. ___(RAM-3) for the betas of this sample of widely-traded investment-grade vertically integrated electric utilities.

I also examined the average beta of the companies that make up Moody's Electric Utility Index as a second proxy. The average beta for the group is 0.92, the same as the previous estimate. Please see Exhibit No. ___(RAM-4) for the betas of the companies in the Moody's Electric Utility Index.

Finally, as a check on the two previous estimates, I examined the betas of investment-grade dividend-paying Western electric utilities as reported in Value Line. The average beta for the Western electric utility group is 0.94, which is very close to the two previous estimates. Please see Exhibit No. ___(RAM-5) for the betas of investment-grade dividend-paying Western electric utilities as reported in Value Line.

Based on these results, I use 0.92 as a reasonable estimate for the beta applicable to PSE's utility business.

4. <u>Market Risk Premium</u>

Q. What market risk premium estimate did you use in your CAPM analysis?

A. For the market risk premium, I used 7.1%. This estimate was based on the results of both historical and forward-looking studies of long-term risk premiums. First, the Ibbotson Associates (now Morningstar) study, *Stocks, Bonds, Bills, and*

Inflation, 2007 Yearbook, compiling historical returns from 1926 to 2006, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.5%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.1%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. This is because the income component of total bond returns (i.e. the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2005) market risk premium (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5%.

Second, a DCF analysis applied to the aggregate equity market also indicates a prospective market risk premium of 7.1%. Therefore, I employ 7.1% as a reasonable estimate of the market risk premium.

Q. On what maturity bond does the Ibbotson historical risk premium data rely?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2006 period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-

2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

Q. Why did you use long time periods in arriving at your historical market risk premium estimate?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the market risk premium in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. Please describe your prospective approach in deriving the market risk premium in the CAPM analysis.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's Investment Analyzer software. The September 2007 edition of the Value Line Investment Analyzer reports that the dividend yield on the S&P 500 Index is currently 1.62% and the average projected long-term growth rate in dividends is 10.19%. Adding the spot dividend yield to the growth component produces an expected return on the aggregate equity market of 11.81%.

Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 11.98%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the market risk premium estimate to approximately 12.18%. Subtracting the risk-free rate of 5.0% from the latter, the implied risk premium is 7.18% over long-term U.S. Treasury bonds, virtually the same number as the historical estimate.

As a check on the market risk premium estimate, I examined a 2003 comprehensive article published in Financial Management by Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the prospective expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate (Column 2) for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.20%, which is almost identical to my own estimate of 7.18%.

DCF Market

[1] R.S. Harris, *et al.*, "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, at 51-66.

Year	Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

Q. What is your risk premium estimate of the Company's cost of equity using the CAPM approach?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.0%, a beta of 0.94, and a market risk premium of 7.1%, the CAPM estimate of the cost of common equity is: 5.0% + 0.92 x 7.1% = 11.5%. This estimate becomes 11.8% with flotation costs, discussed later in my testimony.

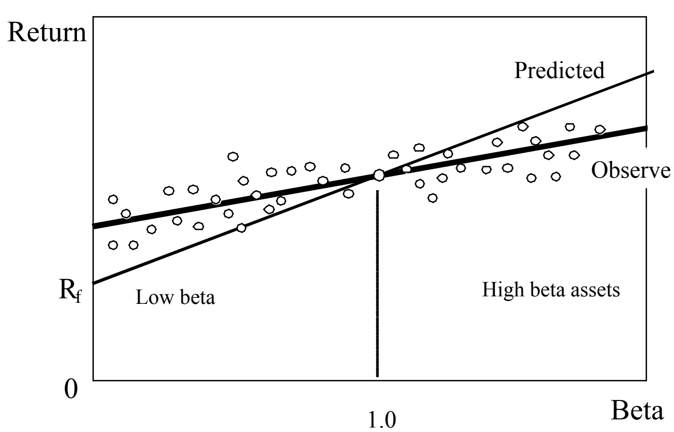
Q. What is your risk premium estimate using the empirical version of the CAPM?

A. With respect to the empirical validity of the plain vanilla CAPM, there have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, The New Regulatory

Finance, published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: vs Observed



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The

ECAPM estimates the cost of capital with the equation:

$$K = R_F \quad \acute{\alpha} + \beta \times (MRP - \acute{\alpha})$$

where the symbol alpha, $\acute{\alpha}$, represents the "constant" of the risk-return line, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Exhibit No. ___(RAM-6) contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

Inserting 5.0% for the risk-free rate R_F, a MRP of 7.1% for $(R_M - R_F)$ and a beta of 0.94 in the above equation, the return on common equity is 11.67%. This estimate becomes 11.97% with flotation costs, discussed later in my testimony.

Q. Is the use of the ECAPM consistent with the use of adjusted betas?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Ibbotson Associates. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated.

Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for the interest rate sensitivity of utility stocks not captured by unadjusted betas.

5. CAPM Estimates

Q. Please summarize your CAPM estimates.

A. The table below summarizes the common equity estimates obtained from my CAPM studies. The average CAPM result is 11.9%.

CAPM Method	ROE
Traditional CAPM	11.83%
Empirical CAPM	11.97%
AVERAGE	**11.90%**

C. Risk Premium Analyses

1. Historical Risk Premium Analysis of the Electric Utility Industry

Q. Please describe your historical risk premium analysis of the electric utility industry?

A. An historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the industry as a whole, using Moody's Electric Utility Index as an industry proxy. Please see Exhibit No. ___(RAM-7) for the historical risk premium for the electric utility industry, using Moody's Electric Utility Index as an industry proxy. The risk premium was estimated by computing the actual realized return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Data for this particular index was unavailable beyond 2002 following the acquisition of Moody's by Mergent.

The average risk premium over the period was 5.5% over historical long-term Treasury bond returns and 5.6% over long-term Treasury bond yields. Given that the risk-free rate is 5.0%, the implied cost of equity for the average electric utility from this particular method is 5.0% + 5.6% = 10.6% without flotation costs and 10.9% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. How does the inclusion of recent risk premium data alter these results?

A. The historical risk premium analysis for the electric utility industry stops in 2002 because the market data on the Moody's Electric Utility Index were discontinued following the acquisition of Moody's by Mergent in 2002. I did examine more recent historical bond return and equity return data based on the S&P Electric Utility Index instead of Moody's Electric Utility Index. The addition of 2002-2005 data does not alter the historical risk premium appreciably. This result is not surprising in view of the rising equity market and low interest rate environment in the 2003-2005 period.

Q. Dr. Morin, are risk premium studies widely used?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or investment management texts including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook (Financial Management: Theory and Practice, 11th ed., South-Western, 2005), recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

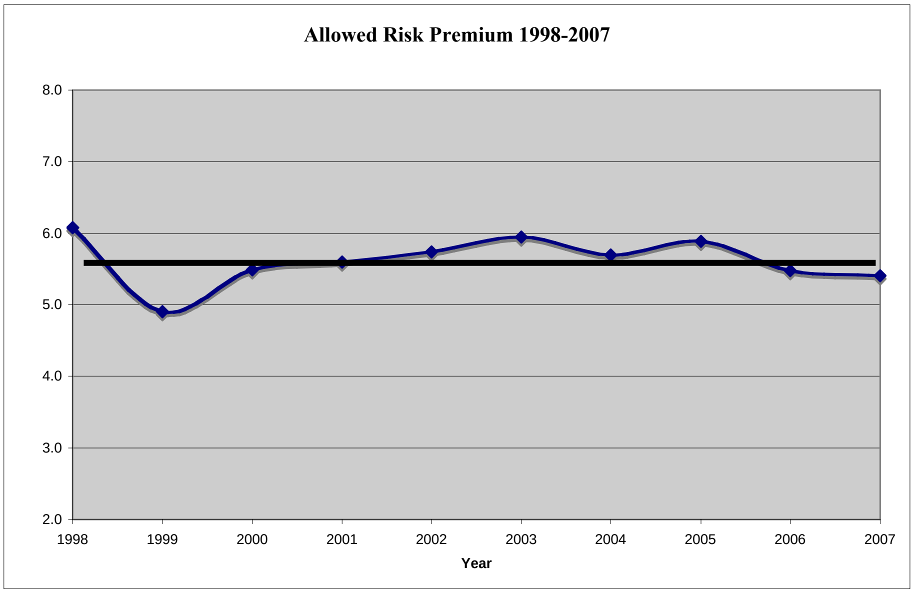
Q. Are you concerned about the realism of the assumptions that underlie the historical risk premium method?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never invest any money.

2. Allowed Risk Premiums in the Electric Utility Industry (1998-2007)

Q. Please describe your analysis of allowed risk premiums in the electric utility industry?

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, *etc.*) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates ("RRA") and easily verifiable from RRA publications and past commission decision archives. The average ROE spread over long-term Treasury yields was 5.6% for the 1998-2007 time period, as shown in the graph below. I note that this estimate is identical to the one obtained from the historical risk premium study of the electric utility industry.



Given the current long-term Treasury bond yield of 5.0% and a risk premium of 5.6%, the implied allowed ROE for the average risk electric utility is 10.6%. No flotation cost adjustment is required here since the return figures are allowed book returns on common equity capital.

Q. Why did you rely on the last decade to conduct your allowed risk premium analysis?

A. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Do investors take into account allowed returns in formulating their return expectations?

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and RRA. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

3. Risk Premium Estimates

Q. Please summarize your risk premium estimates.

A. The following table summarizes the ROE estimates obtained from the three risk premium studies and the average risk premium result is 10.8%.

Risk Premium Method	ROE
Historical Risk Premium Electric	10.9%
Allowed Risk Premium	10.6%
AVERAGE	**10.8%**

D. DCF Estimates

1. Background

Q. Please describe the DCF approach to estimating the cost of equity capital.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity
D_1 = expected dividend at the end of the coming year
P_o = current stock price
g = expected growth rate of dividends, earnings, book value, stock price

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, Regulatory Finance, and Chapter 8 of my new text, The New Regulatory Finance. The standard DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. Is the constant growth DCF model applicable under all circumstances?

A. No, it is not, as I discussed earlier in my testimony. For companies in a mature industry, such as the electric utility industry had been until recent years, it may be reasonable to assume a constant growth rate. For companies in a more dynamic evolving industry, such as the electric utility business today, this assumption may not be reasonable. The dividend growth rate may be expected to converge only over time toward a steady-state long-run level.

2. The Growth Component

Q. How did you estimate the growth component of the DCF model?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. The latter are also conveniently provided in the Value Line software. I also used Value Line's growth forecast as an additional proxy.

Q. Why did you reject the use of historical growth rates in applying the DCF model to electric utilities?

A. The average 5-year historical growth rates in earnings, dividends, and book value for the group are 0.7%, 0.7%, and 1.5%, respectively. Please see Exhibit No. ___(RAM-8), columns 3, 4, and 5, for the historical growth in earnings, dividends, and book value per share over the last five and ten years for the electric utility companies that make up Value Line's Electric Utility composite group. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

Historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five/ten years, due to the structural transformation of the electric utility industry from a fully integrated regulated monopoly to a more competitive environment. These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the 5-year historical growth rates of 0.7%, 0.7%, and 1.5% to the average dividend yield of approximately 4.0% prevailing currently for those same companies, produces preposterous cost of equity estimates of 4.7%, 4.7%, and 5.5%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

I have therefore rejected historical growth rates as proxies for expected growth in the DCF calculation at this time. In any event, historical growth rates are redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.

Q. Did you consider any other method of estimating expected growth to apply the DCF model?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. The latter method has been frequently used by FERC in determining the cost of common equity capital. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE'. That is,

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends
b = expected retention ratio
ROE = expected return on book equity

Q. Do you have any reservations in regards to the sustainable growth method?

A. Yes. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. Did you consider dividend growth in applying the DCF model?

A. No, I did not. This is because it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition and its potential impact on the revenue stream. In other words, earnings and dividends are not expected to grow at the same rate in the future.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The core DCF assumptions of constant perpetual growth and constant payout ratio are clearly not met. The implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for utilities in general. This is because utilities' dividend policies have become increasingly conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Moreover, as a practical matter, while earnings growth forecasts are widely available, there are very few dividend growth forecasts.

Q. Is there any empirical evidence documenting the importance of earnings in evaluating investors' growth expectations?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, and Multex provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

3. <u>DCF Analysis</u>

a. <u>Use of Three Proxies for PSE</u>

Q. How did you estimate PSE's cost of equity with the DCF model?

A. I applied the DCF model to three proxies for PSE: the parent company Puget Energy, a group of investment-grade dividend-paying integrated electric utilities, and a group consisting of the companies that make up Moody's Electric Utility Index.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/Po) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the latest edition of Value Line's VLIA software. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

b. <u>DCF Results for Puget Energy</u>

Q. What DCF results did you obtain for PSE's parent company?

A. Exhibit No. ___(RAM-9) provides the DCF results for PSE's parent company, Puget Energy. As shown on page 1 of Exhibit No. ___(RAM-9), the long-term growth forecast obtained from Value Line is 6.0% for Puget Energy. Combining this growth rate with the expected dividend yield of 4.2% produces an estimate of equity costs of 10.5%. *See id.* at page 1, column 5. Recognition of flotation costs brings the cost of equity estimate to 10.7%. *See id.*, column 6.

Repeating the exact same procedure, only this time using analysts' long-term consensus growth forecast obtained from the Zacks corporate earnings database of 5.5% instead of the Value Line forecast, the cost of equity for Puget Energy is 9.9%, unadjusted for flotation costs. *See* Exhibit No. ___(RAM-9) at page 2, column 5. Adding an allowance for flotation costs brings the cost of equity estimate to 10.2%. *See id.* at column 6.

c. DCF Results for the Integrated Electric Utilities Group

Q. Can you describe your first proxy group of companies?

A. As a second proxy for PSE, I started with a group of investment-grade utilities designated as "integrated" utilities by S&P in a recent comprehensive analysis of utility business risks, meaning that these companies all possess integrated (generation, distribution, transmission) electric utility assets. Please see Exhibit No. ___(RAM-10) for the group of investment-grade utilities designated as "integrated" utilities by S&P.

From this original group, I eliminated foreign companies, private partnerships, private companies, companies below investment-grade (i.e., companies with a bond rating below Baa3), and companies without Value Line coverage. Please see Exhibit No. ___(RAM-11) for the narrowed group of parent companies of investment-grade vertically integrated electric utility utilities.

From this narrowed group, I further eliminated companies that do not pay dividends and companies with market capitalization less than $500 million (to minimize any stock price anomalies due to thin trading). Please see Exhibit No. ___(RAM-12) for the remaining sample of 38 companies.

From this group of 38 companies, I further eliminated companies that derive less than 50% of their revenues from regulated electric utility operations. Please see Exhibit No. ___(RAM-13) for the final proxy group of twenty-five S&P integrated utilities. (Please note that I used the same group earlier in connection with beta estimates.)

Q. What DCF results did you obtain for the integrated electric utility group?

A. Exhibit No. ___(RAM-14) provides the DCF results for the proxy group of twenty-five S&P integrated utilities using the average long-term growth forecast obtained from Value Line. As shown on column 3, line 27 of Exhibit No. ___(RAM-14), the average long-term growth forecast obtained from Value Line is 5.6% for this group. Adding this growth rate to the average expected dividend yield of 4.3% shown in Column 4 produces an estimate of equity costs of 9.9% for the group. Recognition of flotation costs brings the cost of equity estimate to 10.1%, shown in Column 6.

Using the Zacks analysts' consensus forecast of long-term earnings growth instead of the Value Line forecast, the cost of equity for the group is 11.5%. Please see Exhibit No. ___(RAM-15) for the DCF results for the proxy group of twenty-five S&P integrated utilities using the Zacks growth forecast for each company. (Please note that I excluded MGE Energy from such DCF analysis because Zacks did not provide a growth projection for that company.) For the remaining 24 companies, the cost of equity for the group is 11.2% unadjusted for flotation cost using the consensus analysts' earnings growth forecast published by Zacks of 6.9% instead of the Value Line forecast. Recognition of flotation costs brings the cost of equity estimate to 11.5%, shown in column 6, line 26.

d. DCF Results for Moody's Electric Utilities

Q. What DCF results did you obtain for Moody's electric utilities group?

A. Exhibit No. ___(RAM-16) displays the twenty utilities that make up Moody's Electric Utility Index. (Please note that I excluded Duke Energy from such DCF analysis because Value Line did not provide a growth projection for that company.) As shown on column 3 of Exhibit No. ___(RAM-16), the average long-term growth forecast obtained from Value Line is 6.4% for this group. Coupling this growth rate with the average expected dividend yield of 4.2% shown in Column 4 for each company produces an estimate of equity costs of 10.6% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 5 brings the cost of equity estimate to 10.8%, shown in Column 6.

Using the consensus analysts' growth forecast from Zacks instead of the Value Line growth forecast, the cost of equity for the Moody's group is 11.1%. Please see Exhibit No. ___(RAM-17) for the DCF results for the proxy group of twenty Moody's Electric Utility Index utilities using the Zacks growth forecast for each company. (Please note that I excluded CH Energy from such DCF analysis because Zacks did not provide a growth projection for that company.) Recognition of flotation costs brings the cost of equity estimate to 11.3%, shown in column 6, line 19.

4. DCF Estimates

Q. Please summarize your DCF estimates.

A. The table below summarizes the DCF estimates. The average result is 10.8%.

DCF STUDY	ROE
Parent Company Value Line Growth	10.7%
Parent Company Zacks Growth	10.2%
Vertically Integrated Elec Utilities Value Line Growth	10.1%
Vertically Integrated Elec Utilities Zacks Growth	11.5%
Moody's Elec Utilities Value Line Growth	10.8%
Moody's Elec Utilities Zacks Growth	11.3%
AVERAGE	**10.8%**

E. Flotation Cost Adjustment

Q. Please describe the need for a flotation cost allowance.

A. All the market-based estimates reported above include an adjustment for flotation costs. Common equity capital is not free, and flotation costs associated with stock issues are similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Exhibit No. ___(RAM-18) discusses flotation costs in detail, and shows: (i) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (ii) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (iii) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Exhibit No. ___(RAM-

18), total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. Is a flotation cost adjustment required for an operating subsidiary like PSE that does not trade publicly?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate parent, in this case, Puget Energy. This objection is unfounded because the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

F. Summary of Cost of Equity Capital Estimates

Q. Please summarize your results and recommendation.

A. To arrive at my final recommendation, I performed four risk premium analyses.

For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term Treasury bonds. I also performed DCF analyses on three surrogates for PSE: the parent company, a group of investment-grade vertically integrated electric utilities, and a group of companies that make up Moody's Electric Utility Index. The results are summarized in the table below.

STUDY	ROE
CAPM	11.8%
Empirical CAPM	12.0%
Risk Premium Electric	10.9%
Allowed Risk Premium	10.7%
DCF Parent Company Value Line Growth	10.7%
DCF Parent Company Zacks Growth	10.2%
DCF Vert. Integrated Electric Utilities Value Line Growth	10.1%
DCF Vert. Integrated Electric Utilities Zacks Growth	11.5%
DCF Moody's Elec Utilities Value Line Growth	10.8%
DCF Moody's Elec Utilities Zacks Growth	11.3%

The central tendency of the results is 11.0% for the average risk utility, as indicated by the mean (11.0%), truncated mean (11.0%), and midpoint (11.0%) results, and the various results are closely clustered around 11%. From a broad methodological perspective, the average result from the three principal methodologies is 11.2%:

Methodology	ROE
CAPM	11.9%
Risk Premium	10.8%
DCF	10.8%

AVERAGE	**11.2%**

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer the cost of common equity from that number alone.

IV. ADJUSTMENT TO THE ESTIMATED ROE TO ACCOUNT FOR THE FACT THAT PSE IS RISKIER THAN THE AVERAGE ELECTRIC UTILITY

Q. Have you adjusted the cost of equity estimates to account for the fact that PSE is riskier than the average electric utility?

A. Yes, I have. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier PSE is downward-biased. As explained in detail below, PSE's distinguishing risk features relative to its peers is related mainly, but not exclusively, to PSE's gargantuan capital spending program for the next several years and the various risks associated with such an ambitious construction program.

Q. Please comment on PSE's investment risks relative to other electric utilities.

A. Four major factors drive PSE's higher risk profile relative to other utilities: construction risk, power costs risks and the Company's PCA Mechanism, regulatory lag, and financial risk.

A. <u>Construction Risk</u>

Q. Please comment on the construction risks faced by PSE.

A. The term construction risk refers to the financial risks caused by the magnitude of a company's capital budget. Capital expenditures to meet anticipated increases in demand, refurbish old infrastructure, and increase internal power generation to reduce power cost volatility represent an important source of risk. On the one hand, anticipated increases in demand are more difficult to forecast than existing demand. Because of the relatively long lead times associated with utility planning and construction of new plant, there is significant risk that demand will be less than the level forecasted when the new capital investment was planned. On the other hand, a large construction program increases both financial and regulatory risks.

PSE has a massive construction program relative to its size, some estimated $1.5 billion scheduled capital spending for calendar years 2008 and 2009 alone. To place this number in perspective, that represents an increase of some 27% in its net utility plant for the next two years alone. The Company's ability (through its parent) to tap capital markets and attract funds on reasonable terms occurs at a crucial point in time when the Company has an ambitious capital expenditures program and requires external financing. PSE's large capital expenditure program over the next several years, relative to its size, increases its dependence on capital markets which have become volatile and more unpredictable.

PSE's massive construction requirements also have a substantial impact on its financial risk. The Company will require substantial external financing over the next few years. It is imperative the Company have access to capital funds at reasonable terms and conditions. The Company must secure outside funds from capital markets to finance new required capacity, irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Construction is one of the key determinants of credit quality, and hence capital costs. The construction budget relative to internal cash generation is a key quantitative determinant of financial risk. The Company will need to rely heavily on capital markets to finance its construction program.

For debt markets, construction is one of several key determinants of credit quality and, hence, of capital costs. Company future construction plans are scrutinized by bond rating agencies before assessing credit quality. The construction budget in relation to internal cash generation is a key quantitative determinant of credit quality, along with construction expenditures as a proportion of capitalization. Construction to capitalization and common equity ratios are also analyzed by investors and become key determinants of capital costs and funds availability. More generally, the empirical finance literature has demonstrated clearly that construction is a key determinant of a utility's capital costs.

Because of PSE's large construction program over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Uncertainty of approval increases forecasting and planning risks and complicates the utility's ability to devise an optimum transmission/distribution system. Regulatory approval for financings required for new construction may also be required, injecting additional risks.

B. <u>Power Costs Risks</u>

Q. Dr. Morin, can you please comment on the Company's power cost risk?

A. Yes. Because of the Company's predominantly hydro-based generating capacity, a dominant element of business risk peculiar to PSE is a significant reliance on a volatile water supply and on replacement power.

Q. Dr. Morin, can you please comment on the impact of the PCA Mechanism on the Company's investment risk?

A. Yes, certainly. The PCA Mechanism serves to reimburse PSE for certain types of prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. The PCA Mechanism likewise helps lower the risk related to energy costs for PSE although the specifics of the PCA Mechanism are such that the risks inherent in the mechanism are higher than the norm. The financial community relies on the presence of energy cost recovery mechanisms such as the PCA Mechanism to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of PCA Mechanism, thus weakening the Company's financial integrity. The PCA Mechanism mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element, which in turn raises its cost of capital, as discussed above.

The approval of cost recovery mechanisms (fuel adjustment clauses, purchased water adjustment clauses, environmental riders, and purchased gas adjustment clauses) by regulatory commissions is widespread in the utility business. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of PSE's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms within a particular jurisdiction.

C. Regulatory Lag

Q. Is the Company's exposure to regulatory lag significant?

A. Yes, it is relative to other utilities. Although the state's regulatory climate has been restrictive in the past, the Commission's more recent orders have generally been fair and reasonable. The Commission's approval of the Power Cost Only Rate Case ("PCORC") process was a particularly positive step toward supporting PSE's need to obtain new resources for its electric customers. It is crucial that the supportive regulatory climate continue given that strong regulatory relief is critical to the Company's future. As evidenced from several investment research and credit agency reports on the Company, investors are keenly aware of the need for strong regulatory support. In the current environment of volatile and rising fuel and purchased power costs, of record-high capital spending to procure new generation resources, timely and adequate regulatory support is critical to the Company's future. However, because rate decisions cannot be implemented retroactively, the Company's exposure to regulatory lag remains substantial relative to other utilities.

The problem of regulatory lag is well-known in the utility industry and is particularly acute in the case of PSE. Its presence makes it difficult to earn a reasonable rate of return, especially in an inflationary environment. In fact, PSE has been unable to earn its allowed return for the past five years. Regulatory lag also creates mismatches between regulatory rates and supply-demand-costs so that prices are either too high or too low. Inefficient resource allocation and distorted consumer pricing signals may result. One expedient solution to the regulatory lag issue is the use of forward test years rather than historical test years. Another solution is to pass through to ratepayers external power costs on a dollar-for-dollar basis without deadbands (a process that can remain subject to audit, including potential challenges for prudence).

Notwithstanding the regulatory lag issue, there are material regulatory challenges ahead, not the least of which is the uncertainty surrounding potential revisions to or elimination of the PCORC process and the need for very large capital investments in the near future. My recommended ROE range for PSE in this case assumes continuation of the PCORC process in its present form.

D. <u>Financial Risk</u>

Q. Dr. Morin, what do you mean by financial risks?

A. Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt capital. Although the use of fixed cost capital (debt and preferred stock) can offer financial advantages through the possibility of leverage of earnings, it creates additional risk due to the fixed contractual obligations associated with such capital. Debt carries fixed charge burdens which must be supported by the Company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the Company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk.

1. Effect of Imputed Debt On Capital Structure

Q. Dr. Morin, how do purchased power contracts affect an electric utility's financial risk profile?

A. An electric utility with long-term purchased power contracts such as PSE possesses higher financial risks than a utility without such contracts, all else remaining constant. A company's obligations pursuant to long-term purchased power contracts are comparable to long-term debt and are treated as such by investors and bond rating agencies. The same is true for leveraged lease arrangements. In a recent article in Standard and Poor's The Global Sector Review, dated May 8, 2003, S & P updated its criteria for capital structure treatment of purchased power agreements ("PPA"), noting that industry changes warranted "recognition of a higher debt equivalent when capitalizing PPAs." S &

P explained that this more stringent treatment would be factored into its current policy of adjusting the debt/equity ratio of a company for debt equivalents:

> The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Non-capitalized leases, debt guarantees, receivables financing and *purchased power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios.*

The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's purchased power contract obligations are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk.

Q. Does financial theory provide a reasonable and consistent method of adjusting for the increased risk and return associated with purchased power contracts?

A. Yes, it does. The cost of equity for a company with substantial purchased power contracts is higher because that company's effective leverage is higher than otherwise would be the case. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing and/or debt equivalents. In other words, the greater the effective debt ratio, the greater the return required by equity investors.

Several researchers have studied the empirical relationship between the cost of capital and effective capital-structure changes. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities are summarized in Morin, The New Regulatory Finance, at chapter 17 (Public Utilities Report, Inc., Arlington, VA, 2006).

The results of empirical studies and theoretical studies indicate that equity costs increase from as little as 34 to as much as 237 basis points when the debt ratio increases by ten percentage points. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.

Q. Can you provide a numerical example of the manner in which debt equivalents increase the cost of equity?

A. Yes, I can. Consider an electric utility with a capital structure consisting of 50% debt capital and 50% common equity capital without any debt equivalents, and whose cost of common equity has been determined to be 11%. For illustrative purposes, let us assume that long-term purchased power contracts raise the company's effective debt ratio from 50% to 55%, indicating a significant increase in financial risk. An upward adjustment to the initial cost of common equity estimate of 11.0% would be required to reflect this additional risk. Since the capital structure difference amounts to 5%, that is, 55% - 50% = 5%, the required upward adjustment to the cost of equity ranges from 7.6 to 13.8 basis points times 5, which equals 38 to 69 basis points. The midpoint of this range is about 55 basis points. Therefore, the initial cost of equity of 11% would have to be adjusted upward by 55 basis points, raising the cost of equity from 11.00% to 11.55%, in order to reflect the weaker effective capital structure engendered by the purchased power contract debt equivalents.

Q. How does the inclusion of purchased power contracts affect PSE's common equity ratio?

A. PSE's 2006 year-end capital structure consisted of approximately 45% common equity and 55% debt, unadjusted for purchased power contracts. According to S & P's debt equivalent calculations, the inclusion of PSE's purchased power contracts as debt equivalent lowers PSE's common equity ratio from 45% to approximately 43%, a decrease of 2%. Based on the above calculation, an upward adjustment of approximately 25 basis points to the initial cost of common equity estimate of 11.0% would be required to reflect this additional risk alone.

Q. Did you examine the reasonableness of the Company's test year capital structure?

A. Yes, I did. I have compared PSE's test year capital structure with: 1) the capital structures adopted by regulators for electric and gas utilities, 2) the capital structure benchmark contained in Standard and Poor's ("S&P") Rating Criteria for electric and gas utilities, and 3) the capital structures of comparable risk investor-owned electric and gas utilities.

The July 2007 edition of Regulatory Research Associates' "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 48.7% and 46.8% for electric utilities for 2006 and 2007, versus the Company's unadjusted 45%. The latter figure does not account for the Company's higher than average debt equivalent on account of its purchased power contracts that brings its effective equity ratio below 43%.

I have also compared the Company's test year debt ratio of 55% to the capital structure benchmark contained in Standard and Poor's ("S&P") Rating Criteria for electric and gas utilities. PSE is assigned a Business Risk Position of 4.0 by S&P on a scale of 1.0 to 10.0, with 1.0 being the least risky and 10.0 the most risky. For a utility with a Business Risk Position of 4.0, the debt ratio benchmark for a single "A" bond rating, which I consider optimal for both ratepayers and utility investors, is 45% – 52% versus the Company's 55% debt ratio unadjusted for purchased power debt equivalence. The Company's 55% debt ratio lies well outside the range for a single "A" bond rating. The benchmark for a BBB bond rating is 52% – 62%, again unadjusted for purchased power debt equivalence. For a BBB bond rating, the Company's adjusted debt ratio lies at the midpoint of the range.

Finally, I have examined the actual capital structures of my comparable group of integrated electric utilities as reported by Value Line. The average common equity ratio for the group is 49.6%, nearly 50%. This exceeds Puget Energy's

44.4% common equity ratio. Please see Exhibit No. ___(RAM-19) for the equity ratio of each utility in my proxy group of twenty-five S&P integrated utilities.

Moreover, given the Company's small size relative to other utilities[4], a stronger capital structure, that is, one consisting of a higher proportion of common equity capital, is generally required by investors to offset the small capitalization. It is well documented in the finance literature that investment risk increases as company size diminishes, all else remaining constant. Small firms experience average returns greater than those of large firms that are of equivalent systematic risk (beta) and produce greater returns than could be explained by their risks. Empirically, stocks of small firms earn higher risk-adjusted abnormal returns than those of large firms. Ibbotson Associates' widely-used annual historical return series publication covering the period 1926 to the present reinforces this evidence; the average small stock premium is approximately 6% over the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

I conclude that the Company's common equity ratio of 45% is weak relative to its peers, its small size, the S&P bond rating benchmarks, and especially in light of the chronic need for massive external financing over the next several years. If the Commission imputes a capital structure consisting of substantially more (less) debt than the test year capital structure, the higher (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the Commission ascribes a capital structure different from the test year capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost.

2. Credit Ratings

Q. Dr. Morin, you mentioned earlier the need for an optimal bond rating of at least single A. Could you elaborate on that point?

A. Yes, certainly. It is in both ratepayers' and investors' interest that a regulated utility be financially sound and have the credit rating and financial flexibility needed to (i) cope with the increased operational challenges in today's much more volatile industry environment; (ii) pursue initiatives to further increase performance, and (iii) finance in a timely and cost effective fashion the significant infrastructure investment needs faced in PSE's service territory.

In the utility regulation context, the idea of an optimal strong "A" bond rating for a utility's senior securities is widely supported. That is why the vast majority of utilities in North America migrate to such a bond rating.

I have performed several studies and I have frequently testified on the optimal capital structure for various utilities. One common theme in these studies and testimonies is the desirability of a strong "A" bond rating from both the ratepayers' and investors' standpoint. Chapter 19 of my book *The New Regulatory Finance* describes a capital structure simulation model for electric utilities using market data prior to industry restructuring. The graph below illustrates the major finding of the model, and demonstrates how the cost of capital changes as the debt ratio increases and the bond rating declines.

The horizontal axis shows that as the company substitutes debt for equity, the bond rating progressively deteriorates from "AAA" all the way down to "BAA" and beyond. The vertical axis shows what happens to overall capital costs, hence to rates, as the company continues to substitute debt for equity and its bond rating deteriorates. With each successive substitution of lower-cost debt for higher-cost equity, the average cost of capital declines as the weight of low-cost debt in the weighted average cost of capital increases. An optimal point is reached where the cost advantage of debt is exactly offset by the increased cost of equity. This is the optimal capital structure point. Beyond that point, the cost disadvantage of equity outweighs the cost advantage of debt, and the weighted cost of capital rises accordingly. The message from the graph is clear: over the long run, a strong "A" bond rating will minimize the cost of capital to ratepayers.

Several intangible costs and distress costs associated with a low bond rating cannot be readily accommodated into a mathematical simulation model without the model becoming computationally prohibitive. Thus, the case for a strong "A" bond rating is understated in these studies. Several examples of such costs follow.

The need to maintain borrowing capacity is well known. During normal times, a utility company should conserve enough unused borrowing capacity so that during adverse capital market periods it can use this capacity to avoid foregoing investment opportunities, selling stock at confiscatory prices, or jeopardizing its mandated obligation to serve. The yield advantage of a higher bond rating increases dramatically in adverse capital market conditions.

Bond flotation costs, which must be borne by ratepayers, increase also as bond ratings decline, particularly in years of difficult financial markets. Not only is lower bond quality associated with higher yields, but lower-rated utility bonds also carry shorter maturities, especially in poor years. The result is a maturity mismatch between the firm's long-term capital assets and its liabilities. Moreover, lower bond quality is associated with more years of call protection, particularly during difficult financial markets; since bonds are frequently called after a decrease in interest rates, bonds which carry call protection for a greater number of years are more costly to utility companies. Finally, as bond ratings decline, the probability that a company will reduce the dollar amount or shorten the maturity of their bond issues increases dramatically; this in turn reduces the marketability of a bond issue, and hence increases its yield. Any reasonable quantification of such implicit costs reinforces the case for a strong "A" rating.

The implication for PSE is very clear. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings.

Q. Dr. Morin, in light of your discussion of an optimal bond rating, please comment on PSE's capital structure.

A. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings. Moreover, the average bond rating for the electric utility is also in the single A range. In addition, although the legal definition of investment grade is "BBB", the actual practical definition of investment grade is "A". This is because a large majority of institutional investors are precluded from investing in bonds rated below "A". For all these reasons, sound public policy requires that the Commission establish rates so as to create financial conditions conducive to an optimal bond rating of at least single "A".

As discussed earlier, the Company's financial condition is not consistent with a single "A" credit rating. The Company's common equity ratio of 45% is weak relative to its peers, its small size, the S&P bond rating benchmarks, and especially in light of its chronic need for external financing over the next several years. In light of PSE's massive capital expenditure requirements and the critical importance of preserving access to capital markets, PSE's goal should be to achieve strong single "A" credit ratings. Consequently, PSE's credit profile with the two major credit rating agencies needs to improve in order to support an upgrade from its current unsecured rating levels to a Single "A" rated level. This goal implies continued improvement in reducing debt, reducing interest expense and increasing cash flows.

The existence of a strong equity base favorably impacts the cost of debt by virtue of superior credit ratings, allows the company to absorb operating deficits without violating debt servicing obligations, and provides flexibility and freedom in timing new debt issues, in that capital can be raised with discretion under favorable capital market conditions.

V. RELEVANT MARKET CIRCUMSTANCES THAT HAVE CHANGED SINCE THE COMMISSION'S DETERMINATION IN THE COMPANY'S LAST GENERAL RATE CASE

Q. Should the Commission recognize changes in PSE's relevant market circumstances since the Commission's rate of return determination in the Company's last general rate case?

A. Yes. In the final order in the Company's 2006 general rate case, the Commission recognized that changes in PSE's circumstances influence the Commission's consideration of the appropriate rate of return for the Company.

Q. What relevant market circumstances should the Commission consider in

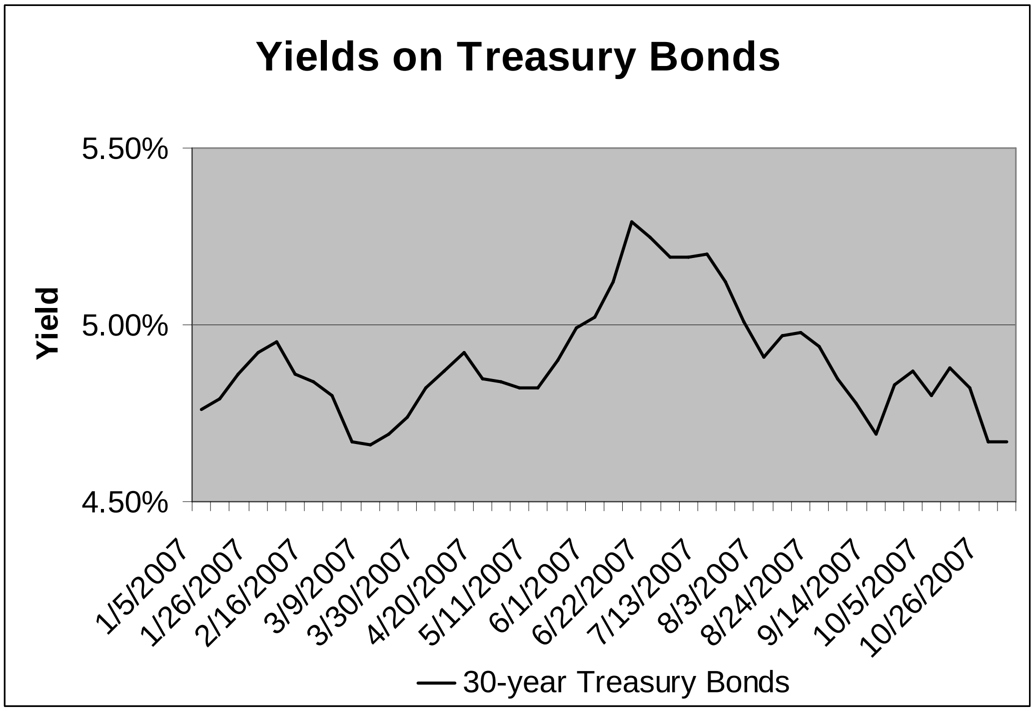
determining the rate of return for the Company in this proceeding?

A. The Commission should consider whether changes have occurred to interest rates, commodity prices, construction costs, and any resulting effect on the Company's capital expenditure program. Additionally, the Commission should consider the effects on the Company of the rate of return determined by the Commission in the Company's last rate case.

1. <u>Interest Rates are Relatively Unchanged</u>

Q. Have interest rates changed since the Commission's determination in the Company's last general rate case?

A. No, yields on long-term Treasury bonds have remained relatively constant since the Commission's final order in the 2006 general rate case, dated January 5, 2007:



Indeed, the yield of 4.67% on 30-year Treasury bonds on November 2, 2007, was only nine basis points lower than the yield of 4.76% on 30-year Treasury bonds on January 5, 2007. Thus, interest rates have remained relatively unchanged since the Commission's final order in the Company's last general rate case.

2. <u>Dramatically Increasing Construction Costs</u>

Q. Have construction costs changed since the Commission's determination in the Company's last general rate case?

A. They certainly have. Not only are there continuing rate increase pressures from elevated fuel and purchased power prices, but there are sharp increases in the costs of building utility infrastructure projects. Due to the high global demand for commodities and manufactured goods and due to higher production and transportation costs, raw materials prices have increased construction costs dramatically in all electric sectors, to the tune of 25% to 35% according to a recent study prepared for the Edison Foundation by the Brattle Group in a September 2007 report entitled "Rising Utility Construction Costs: Sources and Impacts". Please see Exhibit No. ___(SML-4) for a copy of this report.

Although recovery of escalating costs will likely occur later as new infrastructure assets are progressively added to rate base, the resulting upward pressure on an already gargantuan construction budget, the increased regulatory risk resulting from rate increases, and intensified regulatory lag all contribute to heightened overall investment risk. I note that although the need to add infrastructure and generation investments is not peculiar to PSE, the Company's construction budget is far greater relative to its size compared to other utilities.

VI. CONCLUSION

Q. Dr. Morin, what is your final conclusion regarding PSE's cost of equity capital?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity for PSE is in the range of 10.8% to 11.2%. As discussed above, I believe that PSE's total investment risk is slightly higher than the industry at this time. This is corroborated by the Company's below average bond rating in the utility industry. I would therefore recommend that the Commission grant PSE an ROE at the higher end of the 10.8% to 11.2% range to account for the slightly above average risks faced by PSE relative to the industry.. My recommendation is predicated on the adoption of the Company's capital structure consisting of 45% common equity capital.

Q. Are you aware that the Company is seeking an ROE of 10.8 in this case?

A. Yes, I understand that the Company has made a business decision to request an ROE of 10.8, the low end of the range I recommend. I stand by my recommendation that the higher end of the range is appropriate, for the reasons stated above.

Q. Is there a relationship between financial risk and the authorized return on equity?

A. There certainly is, especially now in light of the Company's massive needs for external capital. A low authorized return on equity increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Q. Please explain how low authorized ROEs can increase both the future cost of equity and debt financing.

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, the net proceeds from issuing common stock are reduced because the utility's share price per common stock decreases. Second, the potential risks from dilution of equity investments reduces investors' inclination to purchase new issues of common stock because the utility's market to book ratio decreases with the decrease in the share price of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because (i) debt payments are a fixed financial obligation to the utility, and (ii) income available to common equity is subordinate to fixed charges, additional leverage decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment.

The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs.

Ultimately, to ensure that PSE has access to capital markets for its capital needs, a fair and reasonable authorized ROE of between 10.8% and 11.2% is required.

Q. If capital market conditions change significantly between the date of filing your prepared testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes occur between the time my appraisal of the Company's ROE was done and the time rebuttal testimony or my oral summary testimony is presented, I will update my testimony accordingly.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.