Docket No. RP08 - __________
Exhibit No. EPG - 228

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

El Paso Natural Gas Company | Docket No. RP08-___-000

DIRECT TESTIMONY AND SUPPORTING EXHIBITS OF
MICHAEL J. VILBERT
ON BEHALF OF EL PASO NATURAL GAS COMPANY

June 23, 2008

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I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q2. Please describe your job and your educational experience.

A2. I am a Principal of The Brattle Group, ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco and Brussels. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by El Paso Natural Gas Company ("EPNG" or the "Company") to estimate the cost of equity that the Federal Energy Regulatory Commission (the "FERC" or the "Commission") should allow the Company an opportunity to earn on the equity-financed portion of its rate base for its natural gas transmission assets.

Q4. Please summarize how you approached this task.

A4. To accomplish this task, I select two samples of companies chosen so as to best reflect the business risks of a natural gas pipeline. The first sample, the Baseline Commission-Based Sample" or "Baseline Sample", is chosen from companies with at least 50 percent of their operations from natural gas pipelines. The second sample, the "Extended Sample", is an addition group of companies with at least 50 percent of their operations from natural gas as well as natural gas liquids and petroleum products pipelines. The Extended Sample includes all of the companies from the Baseline Sample. These samples are formed according to the Commission's historical guidelines and the recent policy statement in 123 FERC ¶ 61,048 ("*Policy Statement*"). For each company, I first derive a cost of equity estimate by applying the Commission's favored implementation of the discounted cash flow ("DCF") method, as articulated in the *Policy Statement*. I further consider estimates obtained under an alternative assumption for the long-run growth rate for MLPs. It is my opinion that consideration of both sets of estimates provides a more reliable range of estimates for a natural gas pipeline's cost of equity within the DCF framework. The resulting sets of estimates from the Baseline and Extended Samples are used to form a "range of reasonableness" for EPNG's cost of equity.[1]

Q5. Please summarize the parts of your background and experience that are particularly relevant to your testimony on these matters.

A5. Brattle's specialties include financial economics, regulatory economics, and the gas, water and electric industries. I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. I have testified or filed cost of capital testimony before the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Public Utilities Commission of Ohio, the Tennessee Regulatory Authority, the Public Service Commission of Wisconsin, the South Dakota Utilities Commission, the California Public Utilities Commission, the Canadian National Energy Board, the Alberta Energy and Utilities Board, the Ontario Energy Board, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. I have also filed testimony before this Commission. Appendix A contains more information on my professional qualifications.

Q6. Are you sponsoring any exhibits?

A6. Yes. I am sponsoring Exhibit No. EPG-229, which contains Appendix A. The sources indicated in the footnotes to Tables 4 and 5 refer to material provided in Exhibit No. EPG-230. This exhibit contains the tables and workpapers supporting Tables 1 through 5 of my direct testimony.

Q7. What are the sample results?

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[1] See, *e.g.*, 123 FERC ¶ 61,048, (the "*Policy Statement*"), FERC Order Nos. 414, 414-A, 414-B, and 486 *("Kern River")* plus FERC's decisions in *RP00-107-000 ("Williston Basin")* and RP99-485-000 *("Enbridge")*

A7. The Commission's preferred DCF methodology results in a "range of reasonableness" of between 10.09 and 13.73 percent for the cost of equity, with a median of 12.68 percent. Under a DCF methodology that does not reduce the terminal growth rate of GDP for the Master Limited Partnerships ("MLP") companies in the sample, the range of reasonableness would be between 10.09 and either 13.81 percent or 14.32 percent, depending on the sample chosen, with a median of 13.46 percent.

Q8. Are there other ways to estimate the cost of capital for a FERC-regulated natural gas transmission company?

A8. Certainly. There are many different approaches, and I have used other methods in other FERC proceedings. Each methodology has its own strengths and weaknesses, and they may yield divergent results. The determination of the cost of capital therefore requires the application of informed judgment as well as science.

Q9. Do you believe that the FERC's DCF method is the best method to estimate EPNG's cost of equity for its gas transmission assets in this proceeding?

A9. The cost of capital can be estimated in several ways, and I believe a risk positioning method is generally superior. Moreover, the FERC's preferred DCF method does not directly consider differences in financial risk among the sample companies when establishing the range of reasonableness.

Q10. Why did you not implement these approaches in connection with this proceeding?

A10. The Commission has consistently been skeptical of alternative estimation methods in the past. While I believe that the Commission should not mechanically reject other methods of estimating the cost of capital, I also believe that whatever method the Commission ultimately chooses to use, it should be reasonably consistent from proceeding to proceeding and from company to company. The FERC prescribes the DCF method and has used it in many previous cases to establish the allowed return on equity for other natural gas pipeline companies. It would generally be unfair and would increase regulatory uncertainty if the Commission were to apply its current DCF procedure in one proceeding and ignore it in another for similarly situated natural gas pipeline companies. Selectively applying precedent potentially results in arbitrary estimates of the cost of capital and may result in an unjust and unreasonable allowed rate of return. In this case, EPNG has expressed an interest in minimizing controversy and receiving a return on equity based on applying the FERC's preferred DCF methodology. Within this context, I have implemented the FERC DCF method as faithfully as possible. Specifically, the Baseline results stem from application of the FERC's DCF methodology consistent with precedents in previous cases.

Q11. Considering all of the evidence what is the recommended return on equity for EPNG?

A11. Under the FERC's preferred DCF methodology, the Baseline Commission-Based Sample results indicate an allowed rate of return of either 12.68 or 13.46 percent for a company of the same average risk as the sample – depending on whether or not the terminal growth rate for MLPs is set to one-half of the forecasted long-term GDP growth rate or full GDP growth. In conjunction with other characteristics of the results, this suggests that the Commission should allow a return on equity ("ROE") in the range of 12¾ and 13½ percent, with my best point estimate being 13 percent for a natural gas pipeline of average risk. As discussed by EPNG witness, Ms. Catherine Palazzari, EPNG faces a number of factors that suggest EPNG is likely to be of greater-than-average risk compared to the Baseline Sample. Recognition of EPNG's higher risk would warrant an allowed ROE in the upper end of the range.[2]

Q12. How is your testimony organized?

A12. *Section II* formally defines the cost of capital and touches on the principles relating to the estimation of the cost of capital for a business. *Section II.C* first describes the selection of the Baseline Commission-Based Sample and the Extended Sample. It then describes the Commission's current cost of capital estimation method based upon the DCF model and provides the results of the FERC DCF model for the samples. The section concludes with the recommended cost of equity for EPNG's regulated transmission assets.

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[2] This principle has been affirmed in the Commission's previous opinions, such as *Kern River*, as well as by the U.S. Court of Appeals for the District of Columbia Circuit in *Petal Gas Storage, L.L.C. v. FERC,* 496 F.3d 695 (D.C. Cir. 2007) ("*Petal v. FERC*").

II. COST OF CAPITAL THEORY

A. THE COST OF CAPITAL AND RISK

Q13. Please formally define the "Cost of Capital".

A13. The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk.* In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in this testimony, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 1. The higher the risk, the higher is the cost of capital. A version of Figure 1 applies for all investments. However, for different types of securities, the location (i.e., the intercept and the slope) of the line may depend on corporate and personal tax rates.

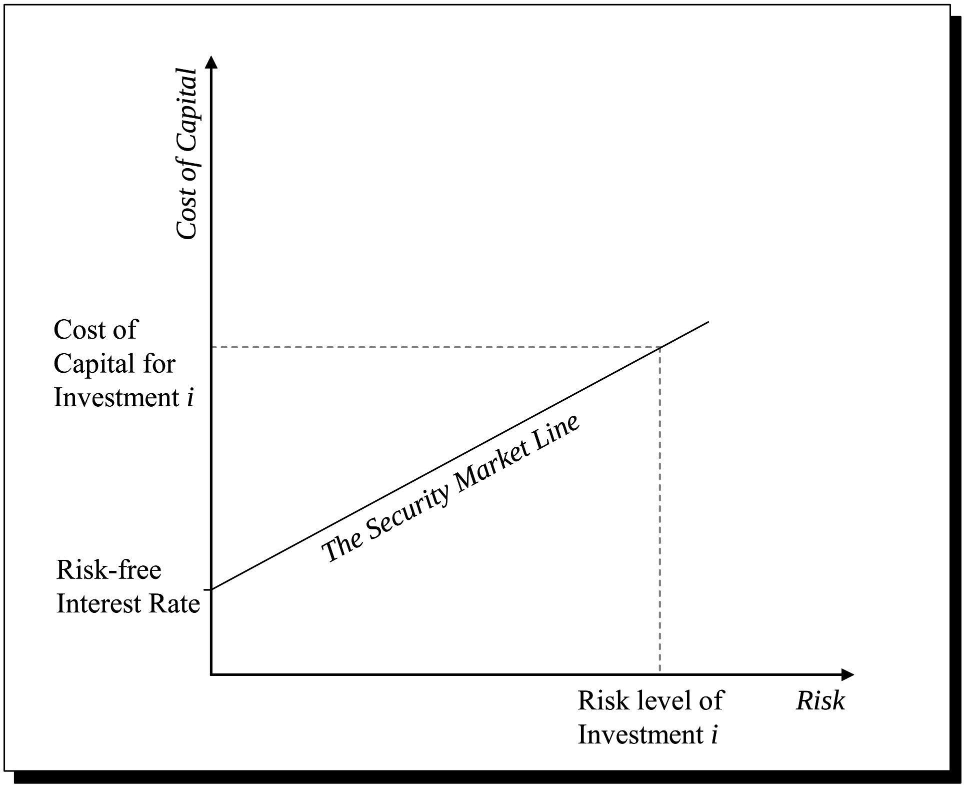

Figure 1: The Security Market Line

Q14. Why is the cost of capital relevant in rate regulation?

A14. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investment.[3] That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (*e.g.*, from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to

[3] A formal link between the cost of capital as defined by financial economics and the right expected rate of return for utilities is established by Stewart C. Myers, *Application of Finance Theory to Public Utility Rate Cases*, *Bell Journal of Economics & Management Science* 3:58-97 (1972).

investors but, importantly, to customers as well. In the long run, such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the economic issues an inadequate return raises for them. In the short run, deviations of the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game" -- investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact, in the short run, such actions may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed or because the company is forced to file more frequent rate cases. In the long run, inadequate returns are likely to cost customers -- and society generally -- far more than is gained in the short run. Inadequate returns lead to inadequate investment, whether for improvements in efficiencies or for new plant and equipment. The costs of an undercapitalized industry can be far greater than the short-run gains from shortfalls in the cost of capital. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that it does not fall short of the cost of capital, either.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital even if the allowed rate of return equals the cost of capital exactly. However, a commission that sets rates so investors expect to earn the cost of capital on average treats both customers and investors fairly, and acts in the long-run interests of both groups.

B. THE DISCOUNTED CASH FLOW APPROACH

1. The General DCF Framework

Q15. Please describe the discounted cash flow approach.

A15. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. It also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T}{(1+k)^T} \tag{1}$$

where "P" is the market price of the stock; "D_t" is the dividend cash flow expected at the end of period t (i.e., subscript period 1, 2, 3 or T in the equation); "k" is the cost of capital for the equity's return risk profile; and "T" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of expected future dividends, each discounted for time and risk between now and the time those dividends are expected to be received.

Very often, when the DCF is applied in regulatory proceedings, very strong (i.e., unrealistic) assumptions are used that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, it is assumed that investors expect a dividend stream that will grow *forever* at a steady rate, and if so, the market price of the stock will be given by a very simple formula:

$$P = \frac{D_1}{(k-g)} \tag{2}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "k" are the market price and the cost of capital, as before. Equation (2) is a simplified version of equation (1) that can be solved to yield the well known "DCF formula" for the cost of capital:

$$\begin{aligned} k &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \tag{3}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (3) says that if equation (2) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future (forever constant) growth rate of dividends. I refer to this as the simple DCF model because this simplification of the model relies on the use of very strong assumptions that are unlikely to reflect actual circumstances.

Q16. Are there other versions of the DCF models besides the "simple" one?

A16. Yes. The constant growth rate DCF model requires that dividends and earnings grow at the same rate for companies that earn their cost of capital on average.[4] It is inconsistent with the theory on which the model is based to have different growth rates in earnings and dividends over the period when growth is assumed to be constant. If the growth in dividends and earnings were expected to vary over some number of years before settling down into a constant growth period, then it would be appropriate to estimate a multistage DCF model. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period. A difference between forecasted dividend and earnings rates therefore is a signal that the facts do not fit the assumptions of the simple DCF model.

2. Strengths and Weaknesses of the DCF Approach

Q17. What are the merits of the DCF approach?

A17. The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong,[5] and hence so unlikely to

[4] Why must the two growth rates be equal in a steady-growth DCF model? Think of earnings as divided between reinvestment, which funds future growth, and dividends. If dividends grow faster than earnings, there is less investment and slower growth each year. Sooner or later dividends will equal earnings. At that point, growth is zero because nothing is being reinvested (dividends are constant). If dividends grow slower than earnings, each year a bigger fraction of earnings are reinvested. That makes for ever faster growth. Both scenarios contradict the steady-growth assumption. So if you observe a company with different expectations for dividend and earnings growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

[5] In this context "strong" means that the assumption is unlikely to match reality and that it also has a substantial impact on the model's results.

correspond to reality. Dividends, earnings and prices are unlikely to grow at a constant rate literally forever. Two conditions are also well known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: the variant of the present value formula that is used must actually match the variations in investor expectations for the growth of dividends, and the growth rate(s) used in that formula must match current investor expectations. Less frequently noted conditions may also create problems.

Q18. Is estimating the "right" dividend growth path the most difficult part for the implementation of the DCF approach?

A18. Yes. The primary issue in implementing a DCF model is to specify a reasonable growth path for expected dividends. Finding the right path, of course, is the "hard part" and the most subjective one. In the simplified models noted above, one either needs to i) estimate a single constant growth rate which is applied to each point in time (simple DCF) or ii) specify short- and long-term growth rates, along with the period of short-term growth and the duration of the transition period before the long-term growth rate applies (multistage DCF).

Q19. How do economists typically specify reasonable growth paths for these DCF implementations?

A19. For simple DCF models, such as those in equation (2), the original approach used to estimate g relied on average historical growth rates in observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates g as the average book rate of return times the fraction of earnings retained within the firm. A major problem with using historical averages over periods with widely varying rates of inflation and costs of capital is that historical data are unlikely to equal current growth rate expectations. An alternative which has demonstrated superior short-run forecasting performance is to use security analysts' growth forecasts. While these have at times been plagued by so-called "optimism bias", institutional reforms such as the Securities and Exchange Commission's significant amendments in 2002 to NASD Rule 2711 of the National Association of Securities Dealers, Inc. ("NASD") and Rule 472 of the New York Stock Exchange (also known as the "SRO Rules") have removed many structural incentives for overestimation of growth rates by analysts. A joint report by NASD and the NYSE in 2005 supports this notion:

> … the SRO Rules have been effective in helping restore integrity to research by minimizing the influences of investment banking and promoting transparency of other potential conflicts of interest. Evidence also suggests that investors are benefiting from more balanced and accurate research to aid their investment decisions.[6]

Although some degree of "optimism bias" may continue to exist to varying degrees, in general, this is not likely to be a major issue for utility stocks.[7] Moreover, studies have repeatedly shown that despite the potential presence of such bias, security analysts' forecasts are much better predictors of short-term growth than the traditional methods outlined above.[8]

Q20. Are you saying that the growth rates could be sustainable forever?

A20. No. Growth rates for all companies vary over time, and no company can maintain a very high rate of growth forever. Conversely, unusually low growth rates will not typically stay low forever. For the purposes of DCF analysis, analyst growth estimates are only the best available estimates for the next five years.

Q21. What about the growth rates for year six and later?

A21. To my knowledge, there is no publicly available information on the expected growth rate of earnings and dividends for time periods more than five years into the future. Use of

[6] Joint Report by NASD and NYSE on the Operation and Effectiveness of the Research Analyst Conflict of Interest Rules, December 2005, pg. 44

[7] See, for example, L. K.C. Chan, J. Karceski, and J. Lakonishok, 2003, "The Level and Persistence of Growth Rates," *Journal of Finance* 58(2):643-684. Results from this study are mixed in general but suggest that it is far from clear how severe the problem of optimism bias may be for regulated utilities, or even whether there is a problem at all.

[8] See, for example, Lawrence D. Brown and Michael S. Rozeff, 1978, "The Superiority of Analysts Forecasts as Measures of Expectations: Evidence from Earnings," *Journal of Finance*, Vol. XXXIII, No. 1, pp. 1-16. J. Cragg and B.G.Malkiel, 1982, *Expectations and the Structure of Share Prices*, National Bureau of Economic Research, University of Chicago Press. R.S. Harris, 1986, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, pp. 58-67. J. H. Vander Weide and W. T. Carleton, 1988, "Investor Growth Expectations: Analysts vs. History," *Journal of Portfolio Management*, Spring, pp. 78-82. T. Lys and S. Sohn, 1990, "The Association Between Revisions of Financial Analysts Earnings Forecasts and Security Price Changes," *Journal of Accounting and Economics*, vol 13, pp. 341-363.

the DCF model is necessarily subject to this limitation. Analysts sometimes attempt to address this problem by making various assumptions about the likely growth path of dividends for the period beginning in year six. Given that there is no recognized source of individual company data upon which to rely, the assumptions used are susceptible to the individual analyst's expectations as to the future.

Q22. Does the use of security analysts' growth forecasts resolve the concerns which arose with earlier methods of estimating the growth rates?

A22. No. The problem with all growth estimates in the context of the constant-growth DCF model is that they can lead to very unreliable estimates if the firm is not currently in a long-run equilibrium. That is, current growth forecasts will not likely be representative of long-run average growth. In these situations, one might be better off implementing a multistage model as I described earlier. With a multistage model, one can use the short-term growth rate as a starting point, typically applying this rate to the first five years of dividend growth. A subsequent period of five to ten years of linear transition to the forecasted terminal growth is also common, where the terminal growth is usually set at some forecast of long-run GDP growth. However, these approaches are subjective because we have no strong economic theory to guide what the terminal growth rate of a given company might be. The use of forecasted GDP growth is simply a reasonable approach which the Commission prefers.

Q23. Can the problems caused by firms being outside of long-run equilibrium be mitigated in the context of a simple DCF model?

A23. Possibly to some extent. One approach is to apply a weighted average constant growth rate – where the average is across a short-term and long-run equilibrium growth rate. As discussed below, the Commission's preferred DCF methodology is one example of this approach. Using a weighted-average growth rate balances the current short-run growth rate with a long-run growth prediction perceived to be more stable. The reliability or accuracy of this approach ultimately depends on what investors expect the true growth of dividends to be. As is true with any simplification, ease of use is being traded for a potential loss of accuracy.

C. THE COMMISSION'S COST OF CAPITAL METHODOLOGY

Q24. How is this section of your testimony organized?

A24. This section first outlines the steps involved in selecting the Baseline and Extended Samples and then provides the specifics of the implementation of the Commission's preferred DCF methodology. Finally, the results of my calculations are presented.

1. Selection of the Commission-Based Samples

Q25. Please describe the Commission's precedent for selecting a sample that accurately reflects the business risk of natural gas transmission.

A25. The Commission recently issued a *Policy Statement* regarding sample composition which provides the most important guidance in this regard.[9] Specifically, the *Policy Statement* deals with the appropriateness of including MLPs in a proxy group for natural gas pipeline operations and the Commission's preferred way of implementing the DCF model for a company organized as a MLP.

Q26. What was the genesis of the *Policy Statement*?

A26. Over recent years, the Commission has had to adapt its criteria for sample selection because of shrinking sample sizes. The Commission's preferred criteria prior to *Williston Basin*, 104 FERC ¶ 61,036 (2003), was to select companies that satisfied the following criteria:

1. The selected company had to be publicly-owned with publicly-traded stock;

2. The selected company had to be recognized by investors as reflective of the risks of natural gas pipelines, own one or more FERC-regulated interstate pipeline, and its stock had to be tracked by an investment information service (such as *Value Line*); and

3. Natural gas pipeline operations had to constitute a high proportion of the company's business, where "high" means that pipeline operations have accounted for at least 50 percent of the company's

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[9] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048. See also 120 FERC ¶ 61,068

assets or 50 percent of their operating income, or both, on average over the most recent three-year period.

Application of these criteria, however, resulted in ever smaller proxy groups to the point that they would be of questionable reliability. For example, in *Williston Basin* where the Commission began to encounter problems constructing a reliable proxy group, only three companies would have survived the criteria laid out above.[10] All parties agreed that sample size was an issue and proposed alternative ways to expand the sample. In those proceedings, the Commission ultimately accepted the company's proposal to expand the sample to nine companies based on the Diversified Natural Gas industry group generated by *Value Line Investment Survey*, all of which owned FERC-regulated natural gas pipelines.

Although the requirement to have at least 50 percent of operations concentrated in the natural gas pipeline industry was relaxed, it proved insufficient over subsequent proceedings. Mergers and acquisitions in the industry, Enron's implosion, and the growing trend of forming MLPs to invest in pipeline assets continued to result in smaller samples under the revised selection criteria. Subsequent decisions in *HIOS*, 110 FERC ¶ 61,043 (2005)[11] (High Island Offshore System, L.L.C.), and *Kern River Transmission Co.*, 117 FERC ¶ 61, 077 (2006) (Opinion No. 486) left the Commission with a four company proxy group even under the revised criteria.[12] To remedy this problem, HIOS and Kern River each proposed the inclusion of three MLP companies in the proxy group, citing the fact that these were primarily pipelines and were therefore highly representative of a natural gas pipeline's business risk.[13] The Commission, however, rejected MLP inclusion at the time since there was disagreement as to the correct way to estimate the

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[10] These were El Paso Corporation, Enron Corporation, and the Williams Companies. Together with a fourth company, Coastal Corporation, these companies made up the historical proxy group that the Commission had used in the past. Coastal Corporation, however, merged with El Paso in January 2001, and Enron went bankrupt.

[11] *Order on reh'g, 112 FERC ¶ 61,050 (2005)*

[12] Six corporations satisfied the traditional criteria, but El Paso Corporation and the William Companies were removed from the sample at the time, because they were facing financial distress that made them unrepresentative of a financially healthy natural gas pipeline.

[13] See the *HIOS* and *Kern River* decisions

MLPs' costs of capital. Moreover, the record in those proceedings did not adequately address Commission concerns.[14] In *Petal v. FERC*, the U.S. Court of Appeals for the District of Columbia Circuit weighed into the issue and held that the Commission had failed to support its choice of proxy groups in *HIOS* and *Petal*. The court emphasized that the Commission's "proxy group arrangements must be risk-appropriate."[15] The court explained that this means that firms included in the proxy group should face similar risks to the pipeline whose ROE is being determined, and any differences in risk should be recognized in determining where to place the pipeline in the proxy group range of reasonable returns:

> The Commission does address the issue of relative risk when it places HIOS in the middle of the proxy group in terms of return on equity. But in doing so, the Commission expressly relies on the "assumption that pipelines generally fall into a broad range of average risk . . . as compared to other pipelines"—an assumption that is decisive only given a proxy group composed of other pipelines… If gas distribution companies generally face lower risks than gas pipeline companies (as seems likely), a risk appropriate placement would be at the high end of the group.[16]

To address the MLP issue, the Commission scheduled a technical conference in July 2007 in order to establish a sufficient record on how to estimate correctly a MLP's cost of equity and under what conditions MLPs could properly be included in a pipeline proxy group.[17]

The ultimate result of this process was the *Policy Statement*, which called for inclusion of MLPs in pipeline samples. With the inclusion of MLP pipeline companies, it is currently

[14] The Commission cited concerns regarding the comparability of MLP distributions and corporate dividends, among others. Specifically, since a MLP often distributes in excess of its earnings, the MLP is often said to distribute a return *of* capital in addition to a return *on* capital. An additional concern considered by the Commission was that distribution yields for MLPs in the DCF formulation could be overstated, and thus lead to excessive estimates of the cost of equity capital. It was later found that this perception was misguided, and the Commission properly discarded initial thoughts of capping MLP distributions at earnings in the *Policy Statement*.

[15] *Petal v. FERC* (D.C. Cir. 2007) at pg. 5

[16] *Id.* at pg. 6

[17] I participated in the second round of those proceedings and provided a "benchmark model" as a test of the FERC's DCF model. The benchmark model is a theoretically sound way to model MLP growth and its equity cost-of-capital in the context of a DCF framework, and it explicitly acknowledges the importance of GP equity.

possible to form a reasonable-sized, though limited, sample that closely reflects the business risks of a natural gas pipeline under the spirit of the more desirable pre-2003 criteria.

Q27. Please explain how you selected a sample that is consistent with the Commission's precedent in regards to gas transmission.

A27. I believe that the pre-2003 criteria are a generally good way to form a representative sample, and therefore primarily relied upon these generally in forming a Baseline Sample and an Extended Sample. I also imposed the following additional criteria:

1. The company's stock is publicly traded and has been for the most recent six month period;[18]
2. The company distributes dividends and has done so in the most recent six month period;
3. The company has a bond rating, and it is of investment grade;
4. The company has had no significant amount of merger and acquisition ("M&A") activity in the most recent six month period.[19]

The first two of these additional criteria simply articulate conditions that are demanded by the Commission's own preferred methodology. Conditions 3 and 4 are basic conditions that ensure estimates will not be tainted by issues of financial distress or excessive speculation that often accompanies M&A activity. I consider estimates of assets and/or income from natural gas pipeline operations for the most recent fiscal year, rather than over the previous three years.

Q28. You noted that you considered more than one benchmark sample. Could you please elaborate?

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[18] The most recent six months is necessary since this data is required for the Commission's preferred implementation of the DCF model.

[19] Significant activity is defined as any M&A transaction accounting for greater than 30 percent of the company's pre-merger market value. The criterion is important since M&A activity can often lead to a decoupling of prices from fundamentals in the period leading up to and after the transaction. As a result, inclusion of a company for which this is the case will lead to an unreliable estimate that can contaminate the results from the sample.

A28. Yes. The pre-2003 criteria, along with my additional criteria, produced my Baseline Sample of five companies. While this is not a completely unreasonable size, it falls short of being ideal. Therefore, I considered an Extended Sample that allows for companies with 50 percent of their operations concentrated in either natural gas pipelines or other FERC-regulated liquids pipelines, such as natural gas liquid ("NGL") or petroleum product pipelines, so long as they owned an interstate natural gas pipeline regulated by the FERC. This expanded the sample by an additional four companies (the Extended Sample), which I believe provides a useful check on the results from the Baseline Sample formed using the pre-2003 criteria alone.

Q29. Why is it appropriate to include companies with a greater proportion of NGL or petroleum product operations in a proxy group for natural gas pipeline operations?

A29. An examination of the operating environment of these different types of pipelines suggests to me that there is likely to be little difference in the risk faced by natural gas pipelines and these other pipelines. Although natural gas pipelines may have once been viewed as having less risk than other pipelines, the current market and regulatory environments do not seem to support this view. Examining the current structure of these different types of pipelines leads me to conclude that natural gas pipelines are not universally less risky than NGL or product pipelines, or vice-versa. There are some natural gas pipelines that may be less risky than certain NGL or products pipelines, but there are others that may be more risky. On average, it is reasonable to conclude that the two types of pipelines are comparable in terms of their cost of capital.

Q30. Could you please explain why you believe this is so?

A30. Natural gas pipelines are regulated by the FERC as "contract carriers", which means that capacity is supplied to customers under a series of short- to long-term fixed capacity contracts.[20] In contrast, NGL and other product pipelines are regulated as "common

[20] Interruptible capacity contracts are also possible, which provide a shipper with capacity of secondary priority on the pipeline in relation to firm transportation contracts.

carriers", which means that they sell capacity on a day-to-day basis.[21] In principal this suggests that NGL and products pipelines take on capacity risks that natural gas pipelines do not, but this factor alone does not suggest that one type of pipeline will be riskier than the other. Pipelines face a host of potential risks, and the level of capacity risk may or may not be a significant part of the overall business risk of the pipe. For example, Kinder Morgan Energy Partners, L.P. has a virtual monopoly in transporting petroleum products to most of the California markets (the exception being portions of the Los Angeles and San Francisco areas which are supplied directly from the refineries), and it provides nearly the entire supply of petroleum products for Las Vegas and Reno, Nevada, as well as Phoenix and Tucson, Arizona.[22] In this scenario, it is difficult to see how Kinder Morgan's product pipelines would face more capacity risk than that of an average natural gas pipeline, especially over the regulatory horizon. Conversely, although natural gas pipelines are contract carriers, a large portion of their capacity can be under contract for relatively short periods or may be subject to discounted pricing. There may also be less than full capacity contracted over a long horizon, and the natural gas pipeline may be forced to rely on "interruptible" instead of "firm" capacity sales. In these increasingly common scenarios, the natural gas pipeline's capacity risk is high as well. This is particularly relevant today, where an excess supply of natural gas pipeline capacity in many markets has led to a reduction in long-term firm capacity contracts for natural gas pipelines. In some markets, fewer expiring contracts are being renewed or are being renewed for shorter terms or lower prices.

Q31. Does the existence of index rates for common carriers also affect the relative risks of the two types of pipelines?

A31. Yes. Index rates provide a natural protection for common carriers against rising costs due to inflation, and can help reduce the risk of cost under-recovery in rates relative to

[21] Although common carriers sell on a day-to-day basis, when nominations for transportation exceed capacity, that capacity is rationed based on each shipper's historical product transportation. A purchaser who has historically purchased more capacity will be given greater priority in purchasing day-to-day capacity.

[22] This is according to the Energy Information Administrations website at: *http://www.eia.doe.gov/emeu/steo/pub/special/california/june01article/caoutside.html* as of June 18, 2008.

contract carriers, all else equal.[23] In short, there are a number of factors that can act to either raise or lower the business risk of one type of pipeline versus another. The totality of evidence and theory suggests that these can be considered as comparable, on average, for the purposes of providing a check on the results from the Baseline Sample.

2. The Commission's Preferred DCF Model

Q32. Please describe the Commission's preferred estimation methodology.

A32. The recent *Policy Statement* essentially re-affirms the Commission's preferred DCF methodology as articulated in prior decisions such as *Williston Basin*, *Kern River*, and *HIOS,* but outlines a modification in the case of MLPs which are now permitted to be included in the sample. The one modification suggested for MLPs is to reduce the estimated terminal growth rate to one-half of the long-term GDP growth forecast instead of the full amount of the GDP growth rate forecast used for the C-corporations in the sample.[24]

Q33. Please describe the details of the DCF model traditionally preferred by the Commission to establish the "range of reasonableness".

A33. As noted earlier, the Commission's preferred DCF model is a modification of the standard constant-growth DCF model, where the dividend growth rate is a weighted-average of the company's 5-year analyst growth rate estimates (2/3rd weight), such as those provided by I/B/E/S or Bloomberg ("BEst"), plus a common long-term growth rate estimate (1/3rd weight). Details of the approach are articulated in the FERC Orders 414, 414-A, 414-B, and 486, as well as in *Williston Basin* and RP99-485-000 ("*Enbridge*").[25]

> The Commission uses the Discounted Cash-Flow (DCF) methodology when calculating a range of reasonable rates of return on equity for natural gas pipelines. Under that methodology, the rate of return equals the

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[23] The common carrier pipelines can also apply for cost-of-service rates if they believe that costs are higher than index rates.

[24] This is one way to recognize the Commission's finding that MLP long-term earnings growth of MLP Limited Partner shares is diminished relative to the C-corporation, since a MLP often distributes more than its earnings to its equity holders.

[25] I use security analysts' growth rate forecasts from Bloomberg, termed their BEst forecasts.

> dividend yield (stock price divided by dividends), plus the projected growth in dividends.[26]
>
> For natural gas pipelines, the Commission uses a two-step procedure to determine the projected growth in dividends of the proxy group companies, averaging short-term and long-term growth estimates. The Commission uses five-year Institutional Broker's Estimate System (I/B/E/S) growth projections for each proxy group company for the short-term growth projection. The Commission uses the growth rate of the Gross Domestic Product (GDP) as its long-term growth rate, since the Commission has found that pipeline specific projections of long-term growth cannot reasonably be developed based on available data sources. The Commission averages these growth projections, giving two-thirds weight to the short-term growth projection and one-third weight to the long-term growth projection.[27]

In formulating the DCF model, the Commission further adds an adjustment to the dividends term resulting in the Commission's preferred cost of capital equation:[28]

$$k = \frac{D_0 \times (1 + 0.5g)}{P} + g \qquad \textbf{(4)}$$

Q34. Is the dividend yield simply the current dividend divided by current price in the Commission's preferred approach?

A34. No. The Commission has established a very specific procedure for calculating the dividend yield to use in the DCF formula. Specifically, the "current" dividend yield is to be computed using the prior six months of dividend and price data. One first records the highest price and lowest price on the first trading day of the month for each of the prior six months. The average of these two prices for each month is then divided by the current annualized dividend to produce six monthly dividend yields. Averaging these six dividend yields produces an unadjusted dividend yield for each company. This is then further adjusted by a factor of $(1 + 0.5\ g)$, where g is the company average growth rate, and becomes the adjusted dividend yield that appears in equation (4).

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[26] *Enbridge*, paragraph 214

[27] *Enbridge*, paragraph 215

[28] Prepared Direct Testimony of Commission Trial Staff Witness Randolph A. Barlow in Docket RP07-34-000 (Southwest Gas Storage Company), Exhibit S-8 pages 51-57.

Q35. Why is only one half of the growth rate used to set the dividend yield in the Commission's preferred methodology as opposed to the full growth rate as shown in Equation (2)?

A35. The Commission has chosen this implementation as an adjustment for the timing in how dividends are paid and the fact that they are paid quarterly. However, I disagree with the use of the 0.5 multiplier for the initial growth rate as a matter of economic principle because it violates the basic assumptions of the DCF model. The DCF model is derived under the assumption that dividends grow at the full growth rate for the period. However, since it is the Commission's preferred method, my results follow the Commission's precedent and use this version of the dividend yield in the DCF model.

Q36. The Commission's methodology as outlined in the orders referenced and the recent *Policy Statement* also requires an estimated long-term growth rate for each of the companies. Please explain how this is computed.

A36. Although companies can experience very high rates of growth from time to time (i.e., greater than the growth of the economy as a whole), these high rates cannot generally be expected to last indefinitely. Conversely, very low rates of growth can generally be expected to improve over time. The longest analyst growth forecasts publicly available are for about five years. This lack of information requires that dividend and earnings growth beyond five years be estimated in some way. The standard assumption is that a company will grow at the same rate as the economy in the long term. If it were expected to grow more rapidly, it would become an ever increasing portion of the economy. Similarly, a company expected to grow more slowly than GDP would play a shrinking role in the economy. For purposes of the DCF model, neither outcome seems reasonable.

The Commission's preferred DCF approach prescribes a terminal growth rate equal to the forecast of long-run GDP growth (in nominal terms). Specifically, the growth rate in the Commission's DCF model is the weighted-average of the current I/B/E/S estimate of the company's short-term earning growth and the GDP growth rate forecast, with ⅔ weight on the short-term growth forecast and ⅓ weight on the GDP forecast.[29] For MLPs, the recent policy statement prescribes the use of ½ of the GDP growth rate forecast instead of the full amount as the terminal growth rate.

Q37. You stated that a reasonable estimate of terminal growth for a pipeline is forecasted nominal GDP growth, and indeed, the Commission prescribes this for corporations. Why is the MLP's terminal growth assumed to be less than this if it is an otherwise identical pipeline to that organized as a corporation?

A37. The record and subsequent comments from the January 23rd, 2008 Technical Conference on the topic of MLP growth rates generally support the notion that a MLP and a C-corporation can grow at the same terminal rate in the long-run.[30] However, the record also established a distinction between how a C-corporation and a MLP achieve growth. Specifically, because of the requirement that a MLP distribute substantially all of its free cash-flow, the MLP must rely more heavily on external financing to grow than its corporate counterpart. The MLP finances growth by going to the market for capital to fund projects, whereas a C-corporation can rely, in part, on retained earnings. The increased need to go to the market for capital ultimately implies a higher growth in the number of shares/units outstanding for a MLP than for a C-corporation. Even if the two organizations as a whole are growing at the same rate (in long-run equilibrium), a higher rate of growth in outstanding shares for the MLP means that earnings per MLP unit must grow at a slightly lower rate compared to the C-corporation. How much less, however, is uncertain.

Q38. Does use of one half of the corporate long-term growth appropriately adjust for any differences in expected long-term growth rates of MLPs compared to C-corporations?

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[29] The GDP forecast is taken to be the average of the long-term GDP forecasts produced by the Social Security Administration (50 year horizon), the Energy Information Administration, and Global Insight (see the *Policy Statement*).

[30] I contributed to this record and argued that, in principle, there is nothing to prevent a MLP from growing as fast as a corresponding C-corporation.

A38. No. I do not believe the difference in terminal growth rate would be that great, especially given the Commission's view that a C-corporation's long-run growth rate be set at the forecasted long-run GDP growth. At current and historical levels, use of ½ of the GDP forecast would imply a difference in terminal growth of 2.5 to 3 percent between a C-corporation and otherwise identical MLP. This seems too great a difference. Moreover, there is no consideration of the projected inflation rate in the MLP long-run growth formula. If a MLP's earnings per unit grow at less than inflation, it would have negative real earnings growth. A reasonable economic model would place inflation as the absolute floor of MLP growth – but the one half GDP formula adopted by the Commission could potentially violate this.

Q39. What do you believe is a reasonable estimate of the terminal growth of a MLP?

A39. It is difficult answer this for either a C-corporation or MLP in an absolute sense. However, the relationship between a corporation's potential long-term growth rate and that of an otherwise identical MLP can be discussed more concretely. As I stated above, I do not believe the two are likely to deviate by a significant amount.

Q40. Did you submit testimony to the FERC on this topic, and participated in the Commission's Technical Conference addressing MLP growth?

A40. Yes.

Q41. At that time, you suggested using an average of long-term GDP and an informal Federal Reserve inflation target of two percent as an estimate of long-run MLP growth, correct?

A41. That is correct, however, the purpose of that suggestion was to provide an objective and formulaic way of setting the MLP's long-run growth rate for regulatory proceedings. It satisfied certain conditions I believe are important – the terminal growth rate would always be greater than inflation but a little less than GDP growth, which I believe to be a reasonable assumption for both MLPs as a whole and C-corporations.

Q42. Why didn't the Commission accept your recommendation for the terminal growth rate for the MLPs in the DCF model?

A42. It is my understanding that the Commission felt that my proposal had not been adequately supported, though I do not know what economic theory the Commission relied upon when making its ruling to use ½ of forecast GDP growth. I believe that the Commission's decision to use ½ of forecast GDP growth is likely to underestimate the relative terminal growth rate of a MLP compared to a C-corporation in the DCF model for the reasons outlined above.

Q43. But the Commission found that this number currently comes close to long-run growth estimates from Wachovia. Doesn't that justify the use of the Commission formula?

A43. Respectfully no. As the analyst from Wachovia tried to clarify at the FERC Technical Conference on January 23, 2008, the long-term growth rates that Wachovia analysts sometimes assume are only meant to be conservative parameters for their models.[31] They are not intended to reflect any specific belief as to what a MLP or C-corporations long-term growth rate might really be. Morgan Stanley takes a similar position in their report shortly after the Technical Conference took place:[32]

> At Morgan Stanley, we assume that an MLP will increase its cash flow ~1.5%-3.0% per year beyond 2012. Importantly, we make the same assumption in forecasting long-term growth for our C-Corp companies. Furthermore, Analysts in other sectors take a similar view on long-term growth ~1.5-3.0%. The rationale is to err on the side of conservatism versus making a statement about actual long-term growth.

The Morgan Stanley report explicitly notes that Morgan Stanley assumes the same long-term growth for both MLPs and C-corporations, whatever that rate might be. This is more consistent with my position as well.

Q44. Do you believe that your formula for MLP long-run growth provides a more accurate cost of capital estimate?

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[31] See, for example, the discussions at pp. 77- 78 and pp. 139-140 in the transcript of the January 23, 2008 Technical Conference Hearing.

[32] "Pipeline MLPs - What's in the Pipeline? MLPs: Stewards of Capital and Leaders of Infrastructure", January 28, 2009, Morgan Stanley Research North America, at p. 3

A44. I would say it is a more reasonable estimate given the limited economic theory we have in this regard. In general, however, I believe that the most reasonable approach is to bring in as much evidence as possible to bracket the true cost of capital. This is especially important when determining an appropriate placement in the Commission's "range of reasonableness".

Q45. How do you bracket the cost of capital for a natural gas pipeline?

A45. I consider i) a set of estimates for my sample companies based on the Commission's formula of one-half of long-run GDP growth for MLP companies (full GDP for C-corporations), and ii) a set of estimates using the full level of forecasted long-run GDP growth for both the MLPs and C-corporations in my samples. In my opinion, this encompasses the full range of terminal growth estimates that might reasonably be expected for MLP companies. The two sets of estimates therefore provide an added dimension of information to use in bracketing my recommended return on equity for EPNG (see Figure 2 below).

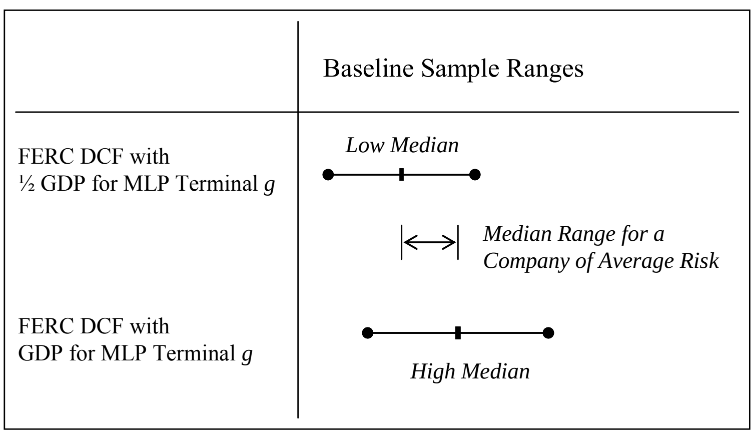

Figure 2: Median bracketed range for a company of average risk

Q46. How is this information for each company translated into a ROE estimate for EPNG?

A46. Each sample's estimates are used to establish a zone of reasonableness, and the corresponding medians are set as benchmark estimates of the cost of equity for companies of average business risk. The Commission's decision in *Enbridge* provides a summary of this approach:

> Once the rates of return for the proxy companies are determined, thereby establishing a range of reasonable returns, the Commission must determine where to set the pipeline's return in that range based upon how the pipeline's risk compares with that of other pipelines. The Commission begins its risk analysis with the assumption that pipelines generally fall within a broad range of average risk, absent highly unusual circumstances that indicate and [sic] anomalously high or low risk as compared to other pipelines. As a result, the Commission has generally placed pipelines at the middle of the range, using the median of the proxy group returns to calculate the middle.

Since I consider both a Baseline and an Extended Sample, the resulting ranges for each – under both DCF approaches – are used in determining my recommendation. Moreover, I also consider the range of median estimates in the Baseline Sample generated by each of the long-term growth assumptions.

III. COST OF EQUITY ESTIMATES

A. THE COMMISSION-BASED SAMPLES

Q47. Please describe your selection of the Commission-Based Samples.

A47. I started with a universe of 56 companies formed by combining companies found either in: i) *Value Line Investment Survey's* Diversified Natural Gas group; ii) the FERC's recent policy statement as example pipeline companies; iii) the National Association of Publicly Traded Partnerships' ("NAPTP") list of Natural Gas pipelines; iv) *Dividend Detective's* list of natural gas pipelines; and v) the FERC's list of regulated interstate natural gas pipelines as found on their website.[33] The initial filtering of companies eliminated companies that were not publicly traded, had a bond rating of less than investment grade (or none at all),[34] had any dividend cuts or paid no dividends in the last six months, and had any substantial mergers or acquisitions within the last six months. After the initial screens, 23 companies remained, which were then examined to determine

[33] These sources were consulted at varying dates between April 17, 2008 and May 2, 2008.

[34] In cases where a company had no bond rating, but was a subsidiary of a rated parent, the parent's credit rating was assigned to the subsidiary.

their proportion of assets, income, or plant, property and equipment ("PP&E") (depending on the information available) devoted to pipeline operations – either natural gas, NGL, or refined products. Companies for which natural gas pipelines and NGL or refined products pipelines together did not account for at least 50 percent of their operations or which did not own a FERC regulated interstate natural gas pipeline were eliminated.[35] This left a total of nine companies that constitute my Extended Commission-Based Sample: Boardwalk Pipeline Partners LP, Enterprise Product Partners LP, Kinder Morgan Energy Partners LP, Oneok Partners LP, Southern Union Co., Spectra Energy Partners LP, TC Pipelines LP, Williams Companies Inc., and Enbridge Energy Partners LP. Of these, only five satisfy the stronger pre-2003 Commission selection criteria: Boardwalk Pipeline Partners LP, Southern Union Co., Spectra Energy Partners LP, TC Pipelines LP, and Williams Companies Inc. These companies constitute my Baseline Commission Based-Sample.

B. CHARACTERISTICS OF THE COMMISSION-BASED SAMPLES

Q48. Please describe the financial characteristics of your samples.

A48. Table 1 below provides basic financial information for the final sample companies, as well as analyst growth forecasts and a summary of the proportion of assets, PP&E, or operating income devoted to natural gas and NGL or products pipelines. Tables 2 and 3 further provide the operating characteristics of each company's FERC regulated natural gas pipelines.

[35] The proportion of pipelines operations or assets relies only on 2007 data.

Table 1: Financial characteristics of the Samples

Company	Pipeline Operations [1]	Revenue (2007) ($MM) [2]	Market Cap. (2007) ($MM) [3]	Market Value Equity Ratio (Q1 2008) [4]	S&P Credit Rating (2007) [5]	LT Growth Estimate [6]
Baseline Sample	*NG Operations*					
Boardwalk Pipeline Partners, LP	*59.58%*	643	3,849	55.79%	BBB	7.65%
Southern Union Co.	61.51%	2,617	3,524	46.63%	BBB-	9.30%
Spectra Energy Partners, LP(b)	57.34%	100	1,620	79.34%	BBB+	8.50%
TC Pipelines, LP (a), (b)	*69.72%*	292	1,263	68.27%	A-	5.67%
Williams Companies	*59.60%*	10,558	20,967	70.20%	BBB-	16.50%
Additional Extended Sample Companies	*NG/NGL/Products Operations*					
Enbridge Energy Partners	93.42%	7,283	4,588	60.95%	BBB	4.25%
Enterprise Products Partners, LP	83.93%	16,950	13,877	64.32%	BBB-	8.73%
Kinder Morgan Energy Partners	55.29%	9,218	13,388	64.18%	BBB	8.70%
Oneok Partners LP	*63.49%*	5,832	5,077	67.84% (c)	BBB	6.60%

Sources and Notes:

[1]: Proportion of operations devoted to Natural Gas Pipelines for the Baseline Sample, and proportions devoted to Natural Gas and NGL/Products pipelines for the Additional Extended Sample Companies. Estimates are based on total assets when available, and either PP&E or operating income otherwise (*italicized entries*). Sources: 2007 company 10-Ks and investor presentations.

[2]: End of year estimate from Bloomberg as of June 9, 2008.

[3]: End of year estimate from Bloomberg as of June 9, 2008.

[4]: Capital Structure Information: Calculations based off Q1 2008 data from Bloomberg.

[5]: End of year estimate from Bloomberg as of June 9, 2008.

[6]: Bloomberg as of June 9, 2008.

(a) TC Pipelines, LP does not consolidate the operations of Northern Borders Pipelines Company and Great Lakes Gas Transmission which are a significant source of TC Pipelines operations. For comparative purposes, the revenue figure here includes 50 percent of Northern Borders' operating revenue, and 46.45 percent from Great Lakes' operating revenue.

(b) S&P Credit Ratings for Spectra Energy Partners, LP and TC Pipelines, LP are derived from parent company (Spectra Energy Corp and TransCanada respectively).

(c) Equity Ratio for Oneok is computed using book-value of debt since its carrying value of debt was unavailable.

Table 2: Operating characteristics of the Baseline Sample companies

Holding Company	FERC Regulated Natural Gas Pipelines [Ownership] [1]	Pipelines (Miles) [2]	States Crossed [3]	Design Capacity (MMcf/d) [4]	Remaining Life of Firm Contracts (avg. years) [5]
Baseline Sample Companies					
Boardwalk Pipeline Partners	Gulf South Pipeline Company, LP [100%]	7,700	TX, LA, MS, AL, FL	4,500	*4.3*
	Texas Gas Transmission, LLC [100%]	5,850	TX, LA, AR, MS, TN, KY, IN, OH, IL	3,800	*3.7*
Southern Union Co	PEPL Transmission System [100%]	1,300	TX, OK, KS, MO, IL, IN, OH, MI	2,800	4.6
	Trunkline Gas Company [100%]	1,400	TX, LA, AR, MS, TN, KY, IL, IN	1,700	9.0
	Sea Robin Pipeline Company [100%]	81	Offshore LA	1,000	n/a
	Florida Gas Transmission Company [50%]	5,000	TX through FL	2,100	8.7
Spectra Energy Partners	East Tennessee Natural Gas [100%]	1,400	TN, GA, NC, VA	1,300	9.0
	Gulfstream [24.5%]	700	MS, AL, FL	1,100	19.0
TC Pipelines LP	Northern Border Pipeline Company [50%]	1,249	MT, ND, WY, IN, SD, MN, IA, IL	2,374	1.3
	Tuscarora Gas Transmission Company [100%]	240	OR, CA, NV	190	10.4
	Great Lakes Gas Transmission [46.45%]	2,115	MN, WI, MI	2,300	2.4
Williams Companies Inc.	Transcontinental Gas Pipeline [100%]	10,300	TX, LA, MS, AL, GA, SC, NC, VA, MD, PA, NJ, NY	8,152	*5.9*
	Northwest Pipeline GP [100%]	3,900	NM, CO, UT, WY, ID, OR, WA, NV	3,300	*8.4*
	Gulfstream [50%]	700	MS, AL, FL	1,100	19.0

Sources and Notes:

[1] Subsidiaries as reported in company 10-K's for significant operations (2007).

[2]-[4] As reported in company 10-K's (2007) or found on company online information.

[5] As reported in company 10-K's (2007) where available. Otherwise, calculated using weighted average remaining contract life according to Company FERC filing Form 549B (*italicized*).

Table 3: Operating characteristics of the additional Extended Sample companies

Holding Company	FERC Regulated Natural Gas Pipelines [Ownership] [1]	Pipelines (Miles) [2]	States Crossed [3]	Design Capacity (MMcf/d) [4]	Remaining Life of Firm Contracts (avg. years) [5]
Additional Extended Sample Companies					
Enbridge Energy Partners	Midla System [100%]	405	LA, MS	200	*3.6*
	AlaTenn System [100%]	281	AL, MS, TN	200	*3.0*
	UTOS [100%]	30	Offshore	1,200	n/a
Enterprise Products Partners	High Island Offshore System [100%]	291	Offshore LA, TN	1,800	*70.7*
	Nautilus System [25.7%]	101	Offshore LA	154	n/a
Kinder Morgan Energy Partners	Kinder Morgan Interstate Gas Transmission LLC [100%]	5,100	WY, CO, KS, MO, NE	2,420	*4.1*
	Trailblazer Pipeline Company [100%]	436	CO, WY, NE	846	*6.0*
	Trans-Colorado Pipeline System [100%]	300	CO, NM	734	*6.5*
	Rockies Express Pipeline [51%]	1,679	CO, WY, NE, KS, MO	1,500	n/a
Oneok Partners LP	Midwestern Gas Transmission Company [100%]	350	IL, IN, KY, TN	1,037	*5.6*
	Viking Gas Transmission Company [100%]	499	MN, WI	496	*2.7*
	Guardian Pipeline, LLC [100%]	143	WI, IL	750	*14.3*
	OkTex Pipeline Company [100%]	298	TX, NM	1,100	*1.8*
	Northern Border Pipeline Company [50%]	1,249	MT, ND, WY, IN, SD, MN, IA, IL	2,374	1.3
El Paso Natural Gas	*El Paso Natural Gas [100%]*	*10,200*	*CA, AZ, NV, NM, OK, TX*	*5,650*	4.0
	The Mojave Pipeline Company System [100%]	*400*	*CA, AZ*	*400*	8.0

Sources and Notes:

[1] Subsidiaries as reported in company 10-K's for significant operations (2007).

[2]-[4] As reported in company 10-K's (2007) or found on company online information.

[5] As reported in company 10-K's (2007) where available. Otherwise, calculated using weighted average remaining contract life according to Company FERC filing Form 549B (*italicized*).

C. THE RANGE OF REASONABLENESS

Q49. What are the results of the application of the Commission's DCF methodology to the sample of pipeline companies?

A49. Table 4 below summarizes the results of the Commission's DCF methodology applied using data through June 2008, which is the most recent data available at the time of this report. The table presents the equation components from the Commission-based formula, as well as summary statistics for both the Baseline and Extended Sample. All companies in the Baseline Sample have a cost of equity estimate greater than 12.60 percent, except for Southern Union Co. which is an outlier. Conversely, there are no outliers in the upper end of the range. Williams Cos Inc. does have a somewhat high growth rate forecast over the next five years, but as discussed above, this high rate is truncated by blending it with the forecast of GDP growth. Moreover, Williams Cos Inc. has an extraordinarily low dividend yield and has an estimate in the upper end of the range that is not inconsistent with the rest of the sample.

Q50. What is significant about the fact that Southern Union Co. is an outlier in the sample?

A50. The fact that Southern Union is such a significant outlier in the sample, with an estimated cost of equity more than 115 basis points lower than the next highest estimate, raises concerns about the reliability of that estimate. It is not clear why Southern Union's estimate might be an outlier, since its characteristics displayed in Tables 1 and 2 are similar to the other companies in the sample. However, the fact that its estimate is unusually low suggests that the upper part of the range may be more representative of the cost of equity for a natural gas pipelines.

Q51. What is the range of reasonableness derived from the samples?

A51. The estimates for the Extended Sample range from a high of 13.73 percent (Williams Cos Inc.) to a low of 10.09 percent (Southern Union Co.), with the sample median of 12.68 percent (TC Pipelines LP). Comparing the results of the Baseline and Extended Sample shows no change in either the range or median of the sample, using the *Policy Statement* methodology. The expansion of the sample to include the four companies with more

NGL and petroleum products operations did not change the results, which supports the view that the two types of pipelines are of comparable risk on average. The range of reasonableness for the Baseline Sample only increases by eight basis points ("bps") when MLP costs of equity are computed using GDP as their terminal growth rate; however, the range of reasonableness increases by 59 bps for the Extended Sample. The general consistency between the Extended Sample's range and Baseline Sample's range suggests a relatively robust estimate of the range and enhances my confidence in the results of the smaller Baseline Sample.

Table 4: Results of the Commission's DCF Method (½ GDP terminal growth for MLP).

Company	Company Type	Dividend Yield [1]	Adjusted Dividend Yield [2]	Terminal Growth [3]	BEst LTG [4]	Combined Growth Rate [5]	Implied Cost of Equity [6]
Baseline Sample							
Boardwalk Pipeline Partners LP	MLP	6.97%	7.17%	2.27%	7.65%	5.86%	13.03%
Southern Union Co	C-Corp	2.29%	2.38%	4.55%	9.30%	7.72%	10.09%
Spectra Energy Partners LP	MLP	5.42%	5.60%	2.27%	8.50%	6.42%	12.02%
TC Pipelines LP	MLP	7.96%	8.14%	2.27%	5.67%	4.54%	12.68%
Williams Cos Inc	C-Corp	1.14%	1.21%	4.55%	16.50%	12.52%	13.73%
Additional Extended Sample Companies							
Enbridge Energy Partners LP	MLP	7.53%	7.67%	2.27%	4.25%	3.59%	11.26%
Enterprise Products Partners LP	MLP	6.56%	6.78%	2.27%	8.73%	6.58%	13.36%
Kinder Morgan Energy Partners LP	MLP	6.76%	6.98%	2.27%	8.70%	6.56%	13.54%
ONEOK Partners LP	MLP	6.86%	7.03%	2.27%	6.60%	5.16%	12.19%
Baseline Sample Statistics:							
Maximum							13.73%
Minimum							10.09%
Median Estimate							**12.68%**
Extended Sample Statistics:							
Maximum							13.73%
Minimum							10.09%
Median Estimate							**12.68%**

Sources and Notes:
[1]: Workpaper #1 to Table No. MJV-4, Panel A, [15].
[2]: [1] * (1 + (0.5 * [5])).
[3]: For C-Corporations, this is equal to a forecast of long-run GDP growth. Forecast GDP growth is computed using an average of the Social Security GDP Long-term Forecast (50 years) and the EIA International Outlook 2007 GDP Forecast. For MLP's, terminal growth is set to ½ of this GDP forecast.
[4]: Bloomberg as of June 09, 2008.
[5]: ((1/3) x [3]) +((2/3) x [4]). This is the weighted average growth rate in the Commission's preferred DCF method.
[6]: [2] + [5].

Table 5: Results of the Unadjusted GDP DCF Method

Company	Company Type	Dividend Yield [1]	Adjusted Dividend Yield [2]	Terminal Growth [3]	BEst LTG [4]	Combined Growth Rate [5]	Implied Cost of Equity [6]
Baseline Sample							
Boardwalk Pipeline Partners LP	MLP	6.97%	7.20%	4.55%	7.65%	6.62%	13.81%
Southern Union Co	C-Corp	2.29%	2.38%	4.55%	9.30%	7.72%	10.09%
Spectra Energy Partners LP	MLP	5.42%	5.62%	4.55%	8.50%	7.18%	12.80%
TC Pipelines LP	MLP	7.96%	8.17%	4.55%	5.67%	5.29%	13.46%
Williams Cos Inc	C-Corp	1.14%	1.21%	4.55%	16.50%	12.52%	13.73%
Additional Extended Sample Companies							
Enbridge Energy Partners LP	MLP	7.53%	7.70%	4.55%	4.25%	4.35%	12.05%
Enterprise Products Partners LP	MLP	6.56%	6.80%	4.55%	8.73%	7.33%	14.14%
Kinder Morgan Energy Partners LP	MLP	6.76%	7.00%	4.55%	8.70%	7.32%	14.32%
ONEOK Partners LP	MLP	6.86%	7.06%	4.55%	6.60%	5.92%	12.97%
Baseline Sample Statistics:							
Maximum							13.81%
Minimum							10.09%
Median Estimate							**13.46%**
Extended Sample Statistics:							
Maximum							14.32%
Minimum							10.09%
Median Estimate							**13.46%**

Sources and Notes:
[1]: Workpaper #1 to Table No. MJV-4, Panel A, [15].
[2]: [1] * (1 + (0.5 * [5])).
[3]: For both MLPs and C-Corporations, this is equal to a forecast of long-run GDP growth. Forecast GDP growth is computed using an average of the Social Security GDP Long-term Forecast (50 years) and the EIA International Outlook 2007 GDP Forecast.
[4]: Bloomberg as of June 09, 2008.
[5]: ((1/3) x [3]) +((2/3) x [4]). This is the weighted average growth rate in the Commission's preferred DCF method.
[6]: [2] + [5].

Q52. What are your conclusions from the FERC DCF model regarding the cost of equity for EPNG's regulated natural gas pipeline assets?

A52. As shown in Table 4 and Table 5 above, the median of the Commission's "range of reasonableness" is 12.68 percent using the methodology specified in the Policy Statement. Using unadjusted GDP for MLPs, the estimates produce a median of 13.46 percent (Table 5). Based on these approaches then, the results currently suggest a cost of equity range of 12¾ to 13½ percent for a natural gas pipeline of average risk.

Q53. Given the results of the DCF models, the Commission's precedent and Ms. Catherine Palazzari's evidence of the relative risk of EPNG's pipeline assets, is the 13 percent rate of return requested by the Company justified?

A53. Yes. The Baseline Sample ranges are 10.09 percent to 13.73 percent using ½ growth for MLPs and 10.09 percent to 13.81 percent for equal MLP and C-corporation terminal growth. Furthermore, the medians bracket a range of 12¾ to 13½ percent. I therefore believe that the Company's request of 13 percent is justified by this methodology for a company of average risk. Ms. Palazzari's testimony argues that EPNG's pipeline assets are likely to be of greater than average business risk in relation to the samples. To the extent that EPNG is of higher risk, it provides additional reason for an allowed return on equity toward the upper end of the range(s) of reasonableness.[36]

Q54. Does this conclude your testimony?

A54. Yes.

[36] As noted previously, this principle has been recognized by this Commission in past decisions such as *Kern River*, and has been demanded by the U.S. Appeals District Court decision in *Petal v. FERC*.

APPENDIX A

RÉSUMÉ

MICHAEL J. VILBERT **PRINCIPAL**

Michael Vilbert is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts' reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team that prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost of capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utility's purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad's cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the ratepayers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

PRESENTATIONS

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

"Issues for Cost of Capital Estimation," with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

"Not Your Father's Rate of Return Methodology," *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

"Cost of Capital Estimation: Issues and Answers," *MidAmerican Regulatory Finance Conference*, Des Moines, IA, April 7, 2005.

"Cost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business," *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

"Current Issues in Cost of Capital," with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

"Current Issues in Estimating the Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, 2006.

"Revisiting the Development of Proxy Groups and Relative Risk Analysis," Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

ARTICLES

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute*, April 2005.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

"Understanding Debt Imputation Issues," by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute,* forthcoming August 2008.

TESTIMONY

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, October 1998.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Written evidence, rebuttal, reply and further reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, Order AO-1-RH-4-2001, May 2001, Nov. 2001, Feb. 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001.

Direct testimony (with William Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002.

Direct testimony and hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-1-000, March 2003.

Direct report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-C1-007, April 2003.

Direct and rebuttal reports before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Proceeding No. 1271597, July 2003, November 2003.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N–7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, RH-2-2004, January 2004.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005.

Direct testimony before the Arizona Corporation Commission, Cost of Capital for Paradise Valley Water Company, a subsidiary of Arizona-American Water Company, Docket No. WS-01303A-05, May 2005.

Written evidence before the Ontario Energy Board, Cost of Capital for Union Gas Limited, Inc., Docket No. EB-2005-0520, January 2006.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission, Return on Equity for Metropolitan Edison Company, Docket No. R-00061366 and Pennsylvania Electric Company, Docket No. R-00061367, April 2006 and August 2006.

Expert report in the United States Tax Court, Docket No. 21309-05, 34th Street Partners, DH Petersburg Investment, LLC and Mid-Atlantic Finance, Partners Other than the Tax Matters Partner, Petitioner, v. Commissioner of Internal Revenue, Respondent, July 28, 2006.

Direct and supplemental testimony before the Federal Energy Regulatory Commission, Docket No. ER06-427-003, on behalf of Mystic Development, LLC on the Cost of Capital for Mystic 8 and 9 Generating Plants Operating Under Reliability Must Run Contract, August 2006 and September 2006.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 5-UR-103, on behalf of Wisconsin Energy Corporation, on the Cost of Capital for Wisconsin Electric Power Company and Wisconsin Gas LLC, May 2007 and October 2007.

Rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-036-39, on behalf of California-American Water Company, on the Cost of Capital, May 2007.

Direct testimony before the Public Utilities Commission of the State of South Dakota, Docket No. NG-07-013, on behalf of NorthWestern Corporation, on the Cost of Capital for NorthWestern Energy Company's natural gas operations in South Dakota, June 2007.

Direct, supplemental and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 07-551-EL-AIR, Case No. 07-552-EL-ATA, Case No. 07-553-EL-AAM, and Case No. 07-554-EL-UNC, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, on the cost of capital for the FirstEnergy Company's Ohio electric distribution utilities, June 2007, January 2008 and February 2008.

Direct testimony before the Public Service Commission of West Virginia, Case No. 07-0998-W-42T, on behalf of West Virginia American Water Company on cost of capital, July 2007.

Direct and rebuttal testimony before the State Corporation Commission of Virginia, Case No. PUE-2007-00066, on behalf of Virginia Electric and Power Company on the cost of capital for its southwest Virginia coal plant, July 2007 and December 2007.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 07-829-GA-AIR, Case No. 07-830-GA-ALT, and Case No. 07-831-GA-AAM, on behalf of Dominion East Ohio Company, on the rate of return for Dominion East Ohio's natural gas distribution operations, September 2007.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-92-000 to Docket No. ER08-92-003, on behalf of Virginia Electric and Power Company, on the Cost of Capital for Transmission Assets, October 2007.

Direct and rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-022, on behalf of California-American Water Company, on the Effect of a Water Revenue Adjustment Mechanism on the Cost of Capital, October 2007 and November 2007.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N–7, as amended, and the Regulations made thereunder; and in the matter of an application by Trans Québec & Maritimes PipeLines Inc. for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital for tolls charged by TQM, December 2007.

Comments in support of The Interstate Natural Gas Association of America's Additional Initial Comments on the FERC's Proposed Policy Statement with regard to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, December, 2007.

Direct testimony on the Cost of Capital before the Tennessee Regulatory Authority, Case No. 08-00039, on behalf of Tennessee American Water Company, March 2008.

Post-Technical Conference Affidavit on behalf of The Interstate Natural Gas Association of America in response to the Reply Comments of the State of Alaska with regard the FERC's Proposed Policy Statement on to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, March, 2008

Direct testimony before the California Public Utilities Commission, Docket No. A.08-____, on behalf of California-American Water Company, concerning Cost of Capital, May 2008, Errata, June 2008.

Rebuttal testimony on the financial risk of Purchased Power Agreements, before the Public Utilities Commission of the State of Colorado, Docket No. 07A-447E, in the matter of the application of Public Service Company of Colorado for approval of its 2007 Colorado Resource Plan, June 2008.