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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Policy for Determining Return on Equity	))	Docket No. PL19-4-000

INITIAL COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Pursuant to the comment procedures set forth in the Notice of Inquiry issued on March 21, 2019 in Docket No. PL19-4-000 (the "NOI"), the Interstate Natural Gas Association of America ("INGAA") submits these initial comments.

INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in the United States. INGAA's 28 members represent the vast majority of interstate natural gas transmission pipeline companies in the U.S. INGAA's members, which operate approximately 200,000 miles of interstate natural gas pipelines, serve as an indispensable link between natural gas producers and consumers. Its members' interstate natural gas pipelines are regulated by the Federal Energy Regulatory Commission ("Commission" or "FERC") pursuant to the Natural Gas Act ("NGA").[1]

[1] 15 U.S.C. §§ 717-717w.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

TABLE OF CONTENTS

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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I. EXECUTIVE SUMMARY

The Commission's return on equity ("ROE") policy should be dynamic and flexible. The policy must reflect more than the rote application of a formula and should avoid applying a one-size-fits-all approach across both interstate pipelines and electric transmission providers. The Supreme Court in *Federal Power Comm'n v Hope Natural Gas Co.*,[2] explained that the ROE earned by the owner of a regulated entity must "be commensurate with returns on investments in other enterprises *having corresponding risks*"[3] Interstate pipelines and electric transmission providers do not have corresponding risks. Each industry is subject to distinct regulatory policies and market forces that create distinct risks.

The greater risk faced by interstate pipelines is reflected in the way that equity investors evaluate the industry. In light of the Supreme Court's directive in *Hope*, this risk is inextricably intertwined with setting appropriate returns. Companies owning interstate pipelines are viewed by investors as having a greater inherent risk than the equity market as a whole. Due to the different levels of risk faced by each industry it regulates, the Commission should recognize that it may be appropriate to apply different ROE methodologies to each industry and/or implement them differently.

In determining ROE policies for interstate pipelines, the Commission must recognize the distinct business risks faced by interstate pipelines, fostered in large part by the Commission's policies over the last 35 years. These policies, starting with Order Nos.

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[2] *Federal Power Commission v Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope").*

[3] *Id.* (emphasis added).

436,[4] 636,[5] and 637[6] created an integrated pipeline network and provided shippers with the flexibility to use their capacity rights on this network to access different supply sources and market hubs, and to utilize their capacity more efficiently. Through its certificate policy, the Commission has actively facilitated pipeline-on-pipeline competition to the benefit of consumers. As a result of these policies, interstate pipelines face robust competition from both other pipelines and from their customers, through capacity release. These competitive pressures have required pipelines to discount their rates to retain and obtain load and have resulted in shippers seeking shorter term contracts to enhance their ability to take advantage of their competitive options.

The competitive risks faced by interstate gas pipelines are asymmetric because pipelines are increasingly forced to reduce rates to meet competition when market conditions are unfavorable, but they cannot command rates above their maximum applicable rates to offset the downside risk when market conditions are favorable.[7] This unbalanced approach to pipeline rates increases the business risks faced by interstate

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[4] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, [Regs. Preambles 1982-1985] FERC Stats. & Regs. ¶ 30,665 at 31,516-17 (1985).

[5] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, [Reg. Preambles Jan. 1991-June 1996] FERC Stats & Regs, ¶ 30,939 at 30,446-48 (1992), *order on reh'g*, Order No. 636-A, [Reg Preambles Jan. 1991-June 1996] FERC Stats & Regs, ¶ 30,950 (1992); *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992*); reh'g denied*, 62 FERC ¶ 61,007 (1993); *aff'd in part and remanded in part*, *United Distrib. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996); *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

[6] *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC, 428 F.3d 255* (D.C. Cir. 2005).

[7] Even in favorable market conditions, a shipper can purchase available pipeline capacity from the pipeline at maximum recourse rates. It can release any unused capacity for a period of less than one year at an uncapped rate.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

pipelines. The Commission's ROE policies should recognize the realities of the current business and regulatory environment.

The Commission utilizes proxy groups to establish a range of reasonable ROEs for interstate pipelines. The Commission has established eligibility criteria designed to ensure that proxy groups include companies with corresponding risks, as required by *Hope*. The list of proxy group-eligible gas pipelines has diminished substantially in recent years due to numerous consolidations across the midstream sector. Few "pure play" publicly traded natural gas pipeline companies exist today, because most gas pipeline assets are held by large energy conglomerates. As a result, many interstate pipelines are held by companies that are currently ineligible for proxy group inclusion. This reduces the statistical accuracy of proxy groups and makes them less representative of the business risks faced by interstate pipelines.

The Commission has wrestled with the composition of the gas pipeline proxy group in the past and has adjusted its policies in a flexible and pragmatic manner. The Commission should continue this approach to proxy group eligibility criteria to ensure sufficiently representative proxy groups. INGAA has three suggestions, two related to the existing metrics used to determine proxy group eligibility and one addition. The Commission should: (1) allow the inclusion of comparable risk companies in proxy groups even if such companies may not strictly meet the "high proportion" of gas pipeline operations threshold; and (2) shorten the period of time during which companies that have undergone recent merger activity are excluded. The Commission should utilize the widely-accepted financial metric, "beta", to help assess risk comparability. The Commission can analyze betas to allow companies with significant natural gas pipeline assets and betas similar to other proxy group members into gas pipeline proxy groups. This will allow FERC to utilize representative proxy groups of comparable risk companies to set pipeline ROEs in compliance with *Hope*.

Proxy group eligibility criteria are of paramount importance in this proceeding, because three of the four methodologies proposed in the NOI utilize proxy groups to determine ROEs: (1) Discounted Cash Flow ("DCF"); (2) Capital Asset Pricing Model ("CAPM"); and (3) Expected Earnings. Thus, regardless of which methodologies FERC ultimately finds to be appropriate for developing gas pipeline ROEs, FERC must address the diminishing number of eligible proxy group companies. The use of beta will allow FERC the flexibility to determine which companies should, and should not, be included in gas pipeline proxy groups.

INGAA proposes that the Commission consider three of the models discussed in the NOI to determine gas pipeline ROEs under both sections 4 and 5 of the NGA: (1) DCF; (2) CAPM; and (3) Expected Earnings. Importantly, regardless of which models it chooses to consider in establishing gas pipeline ROEs, the Commission should *not* apply a rigid mechanical approach of giving equal weight to each methodology. For the very reasons discussed by the Commission in the NOI, the Commission should have the flexibility to apply different weights to the various models in setting ROEs, depending upon current economic conditions and the facts and circumstances of each case. The rationale of considering more than one model is that each model's assumptions may not accurately reflect capital markets and economic conditions when a pipeline's ROE is determined. It may be appropriate, therefore, to give more or less weight to one or more of the models. The Commission should consider expert testimony addressing how the results of the models may be affected by economic and capital market conditions in deciding the weight to be afforded to the models.

Attached to these comments is an affidavit of Dr. Michael J. Vilbert of The Brattle Group, a preeminent expert on the application of cost of capital theory to FERC-regulated industries. In response to the questions raised by the Commission in the NOI, Dr. Vilbert discusses the theoretical underpinnings of the various models, their advantages and disadvantages, and how best to implement each of them in determining natural gas pipeline ROEs.

For the reasons more fully explained by Dr. Vilbert and in these comments, INGAA proposes the Commission should continue to utilize the DCF model for setting gas pipeline ROEs but modify the DCF model to:

1) Take into account a pipeline's Distributable Cash Flow to properly reflect the amount of cash available to pipelines to distribute either to investors or to reinvest;

2) Include stock repurchases or buybacks in the dividend yield component of the DCF formula;

3) Compute the dividend yield on the basis of quarterly, instead of annual, dividends to reflect the actual timing of these payments more accurately;

4) Include short-term growth forecasts from Value Line in addition to those of the Institutional Brokers' Estimate System ("IBES");

5) Reduce the weight given to GDP as a measure of long-term growth in the growth component of the formula from one-third to one-fifth; and

6) Eliminate the 50 percent reduction in long-term growth applied to MLPs, which has become more unreasonable and punitive in light of the Commission's policy of eliminating an income tax allowance for MLPs and other pass-through entities.

Finally, the Commission should confirm that only short-term forecasts be utilized in calculating the "g" component in deriving the dividend yield.

Dr. Vilbert also discusses the CAPM and Expected Earnings models and recommends a preferred approach for implementing these models to set the ROEs of natural gas pipelines. To implement CAPM, Dr. Vilbert recommends the use of a 20-year Treasury bond rate as the risk-free rate. He also proposes that the market risk premium component be calculated using a single-stage DCF analysis of companies in the S&P 500, utilizing a weighted average of Value Line and IBES forecasts for the growth component. Dr. Vilbert recommends that the Expected Earnings model utilize forward-looking expected returns, as applied to the book value of the proxy companies. The use of forecasts substantially reduces, if not entirely eliminates, the circularity inherent in the use of historical returns. Dr. Vilbert's recommendations regarding implementation of the CAPM and Expected Earnings models are generally consistent with the forward-looking approaches accepted by the Commission in Opinion No. 551.[8]

Finally, Dr. Vilbert responds to the Commission's request for comments on the outlier tests applied to the proxy group. He explains that a high-end outlier test is not necessary to the extent the median, as opposed to the midpoint, of the proxy group returns, is used to establish the ROE. Because gas pipeline ROEs are, and should continue to be, set at the median, a high-end outlier test is not needed to set gas pipeline ROEs. Dr. Vilbert also explains that a high-end outlier test should not be applied to a two-step DCF model that utilizes GDP to any degree as a measure of long-term growth because GDP, is by definition, sustainable. He also explains that a high-end outlier test is inconsistent with the financial theory underlying CAPM, which utilizes betas to equate risk and return, and

[8] Opinion No. 551, 156 FERC ¶ 61,234 (2016).

renders the notion of an "atypical" high-end outlier an impossibility for comparable risk companies.

Dr. Vilbert agrees, however, there is a theoretical justification for a low-end outlier test because investors will not rationally purchase common stock if less risky bonds yield essentially the same return. Dr. Vilbert recommends that the Commission adopt a 150-basis point spread over a BBB-rated yield as the minimum threshold for elimination of low-end outliers, and that spread be adjusted based on a market risk premium analysis which recognizes the impact of changes in interest rates. Alternatively, INGAA would recommend a similar interest rate-based approach for calculating a low-end outlier threshold adopted in Opinion No. 531.[9]

[9] Opinion No. 531, 147 FERC ¶ 61,234, at P 147.

II. BACKGROUND

For years, the Commission has used the DCF model to determine the ROE component of the rates for jurisdictional companies. The DCF model is a market-based approach that assumes that the price of a share of common stock is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk.[10] The Commission historically has implemented the DCF model differently for the industries it regulates.[11] Until recently the Commission used a one-step constant growth model for the public utility industry, while using a two-step model, which incorporates different measures of short-term and long-term growth, for the oil and gas pipeline industries.

In Opinion Nos. 531 and 551 involving the rates of the New England Transmission Owners ("NETO"), and Midcontinent Independent System Operator, Inc. ("MISO") Transmission Owners, the Commission concluded that anomalous market conditions were causing the DCF model to produce lower electric utility ROEs than other valuation methodologies. To address this downward bias, the Commission set the ROE of the transmission owners at the midpoint of the upper half of the zone of reasonable returns produced by the DCF model.[12]

In *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"), the D.C. Circuit reversed, vacated and remanded Opinion No. 531. Pertinent to the NOI, the Court agreed that an upward adjustment in ROE to address anomalous market conditions may

[10] NOI at P 5, *citing Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001); *see also Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at P 58 (2008) ("Proxy Group Policy Statement").
[11] *Id.* at P 7.
[12] *Id. citing* Opinion No. 531, 147 FERC ¶ 61,234 (2015); Opinion No. 551, 156 FERC ¶ 61,234 (2016).

have been warranted, but found that the Commission failed to support its chosen adjustment.[13] In response to the Court's remand, the Commission issued two briefing orders in which it proposed to change its approach to determining ROEs for electric utilities to rely on multiple financial models instead of solely the DCF model.[14]

Because Opinion Nos. 531 and 551 arose under section 206 of the Federal Power Act ("FPA"), the Commission proposed slightly different measures applicable to the two-pronged analysis under that section. To determine whether an existing ROE remains just and reasonable, the Commission proposed to develop a composite zone of reasonableness produced by the DCF, CAPM and Expected Earnings models and weigh the results of each of these models equally.[15] To establish a new ROE if the existing ROE is found to be unjust and unreasonable, the Commission proposed to use the average of those same three models plus a fourth -- the Risk Premium Model.[16]

Due to the importance of its ROE policies, the Commission issued the NOI seeking further input from all FERC-jurisdictional industries on the ROE policy changes proposed in the *Coakley/MISO* Briefing Orders. The Commission states its objective is to align estimates of expected returns more closely with how investors make investment decisions. The Commission seeks comments on various aspects of ROE policy, including the appropriateness and application of the four models to the different industries FERC regulates.

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[13] *Id.* at P 22, *citing Emera Maine*, 854 F.3d at 27, 30.
[14] *Id. citing Martha Coakley v. Bangor Hydro-Elec. Co,* 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order); *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* 165 FERC ¶ 61,118 (2018) (*MISO* Briefing Order) (collectively referred to as the "*Coakley/MISO* Briefing Orders").
[15] *Coakley* Briefing Order at P 16; *MISO* Briefing Order at P 18.
[16] *Coakley* Briefing Order at P 17; *MISO* Briefing Order at P 19.

III. COMMENTS

A. <u>The Commission Should Not Apply A One-Size-Fits-All ROE Policy</u>.

The NOI seeks comments on whether the Commission should apply a single ROE policy across the electric, interstate natural gas and oil pipeline industries, and whether there are differences between public utilities and natural gas and oil pipelines that would justify using different methodologies to determine their ROEs.[17] Interstate natural gas pipelines face unique competitive forces and business risk. Such competition and resulting risks must be reflected in the Commission's ROE policies in light of *Hope* in which the Supreme Court explained that the ROE earned by the owner of a regulated entity must "be commensurate with returns on investments in other enterprises *having corresponding risks*" and "be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and to attract capital*."[18] The Commission should avoid a one-size-fits-all approach to the application of its ROE policy and reject any proposals in this proceeding that do not account for the unique business risks faced by interstate pipelines.[19]

1. Interstate Pipelines and Electric Transmission Providers Are Each Subject to Different Regulatory Policies That Create Different Levels of Business Risk.

Although the Commission has restructured both the natural gas and electric industries over the past 25 years, it has adopted different policy approaches for each

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[17] *See* NOI at P 32.

[18] *Hope*, 320 U.S. at 603 (emphasis added).

[19] For example, a white paper prepared by ScottMadden, Inc. for the Edison Electric Institute suggests that the Commission-authorized ROEs for natural gas pipelines are an "appropriate benchmark" for assessing the ROEs of electric transmission providers. *See* Edison Electric Institute, *Transmission Investment: Revisiting the Federal Energy Regulatory Commission's Two-Step DCF Methodology for Calculating Allowed Returns on Equity* (Dec. 2017). This suggestion is based solely on the fact "[e]lectric and natural gas transmission operations both are federally regulated, capital-intensive infrastructure investments." This statement fails to recognize or address the disparate federal regulatory structure and policies which have led to a fiercely competitive interstate natural gas marketplace that places increased risk on interstate pipelines and makes the ROEs of natural gas pipelines an entirely inappropriate benchmark for electric transmission providers and vice versa.

industry. Interstate pipelines and electric utilities each operate under different regulatory structures that create different degrees of business risk. The Commission's policies on the electric side have fostered the development of organized wholesale electric markets administered by Regional Transmission Organizations ("RTOs") or Independent System Operators ("ISOs"). Approximately two-thirds of the U.S. electric load is now served in regions administered by RTOs or ISOs. The Commission requires RTOs and ISOs to undertake regional transmission planning. Electric transmission owners within RTOs and ISOs have certainty regarding the recovery of the costs of transmission facilities built pursuant to the RTO/ISO regional planning process because, their transmission service is subject to only limited competition.

In contrast, unless the roll-in of the costs of an expansion will lower system rates, pipelines are permitted to "recover the costs of the new facilities only from shippers who use them, and are fully at risk for the cost of the new facilities and will bear the financial burden of any unsubscribed capacity."[20] As discussed in detail below, interstate pipelines continue to face substantial competition after facilities have been built and placed in service. The differences in cost recovery policies and exposure to competition substantially differentiate the business risk profile of interstate pipelines from electric transmission providers, and these differences must be reflected in the Commission's ROE policies.

Transmission providers operating outside of RTOs and ISOs also face lesser risks than interstate pipelines since most of their assets operate within franchised service territories, subject to state public utility regulation. Such companies typically dedicate or

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[20] *Certification of New Interstate Natural Gas Facilities*, Notice of Inquiry, 163 FERC ¶ 61,042 at P 17 (2018) (citing the Policy Statement).

sell much of their transmission capacity, as well as the output of the generation assets they own, to their state-regulated distribution divisions, which, in turn, recover those costs in their state-approved, retail rates. The wholesale electric transmission business that is subject to regulation by the Commission typically makes up only a small portion of the overall business of the integrated electric utilities operating in these markets. The business risks of integrated electric utilities operating outside of RTOs and ISOs are not comparable to the risks of interstate pipelines, which are not protected from cost under-recovery.

2. Equity Market Investors Treat Natural Gas Pipelines as Having Greater Inherent Risk Than Electric Transmission Providers.

The many factors that increase interstate pipelines' business risk are reflected in the equity markets. As discussed below in Section C, investors often evaluate the inherent risk of an asset by measuring its "beta." Beta measures the relative risk of an asset compared to the market as a whole by assessing the volatility of the asset as compared to the overall volatility of the market. A beta of 1.00 indicates that an asset has a similar risk to the market as a whole. A beta greater than 1.00 indicates that the asset has a greater inherent risk than the market as a whole, while a beta less than 1.00 indicates that an asset has lesser inherent risk than the market as a whole.

As explained below, the average betas for companies classified as interstate gas pipelines are above 1.00, which reflects greater risk than the overall market, while the average betas associated with companies classified as electric utilities are substantially below 1.00, reflecting lower risk than the overall market. The market-determined differences in beta demonstrate that electric utilities and interstate gas pipelines do not have corresponding risks. Therefore, a one-size-fits-all approach to the development of an ROE policy across these two distinct industries would be contrary to the Supreme Court's requirements for determining a just and reasonable ROE as established in *Hope*.

B. Interstate Gas Pipelines Are Subject to Unique Business Risks.

1. Interstate Gas Pipelines Face Substantial Competition.

In determining its ROE policy for interstate pipelines, the Commission must recognize the highly competitive environment that the Commission has fostered over the past thirty-five years. The Commission's pro-competition policies for interstate pipelines have created substantial benefits for gas consumers by allowing them to access diverse sources of gas supplies and to move those supplies to both new and existing markets. The pro-competition policies have also created unique business risks for interstate natural gas pipelines that must be reflected through higher ROEs at a level commensurate to the returns earned by businesses with corresponding risks. The Commission's policies have increased the risks pipelines face from competition in the following ways:

In Order No. 636,[21] the Commission restructured its regulation of the natural gas pipeline industry by requiring pipelines to unbundle their transportation and sales functions. The Commission's objective in Order No. 636 was "to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers *can meet in a competitive, national market to transact the most efficient deals possible*."[22] Order No. 636 provided shippers more flexibility, including allowing firm transportation

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[21] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, [Reg. Preambles Jan. 1991-June 1996] FERC Stats & Regs, ¶ 30,939 at 30,446-48 (1992), *order on reh'g*, Order No. 636-A, [Reg Preambles Jan. 1991-June 1996] FERC Stats & Regs, ¶ 30,950 (1992); *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992*); reh'g denied*, 62 FERC ¶ 61,007 (1993); *aff'd in part and remanded in part*, *United Distrib. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996); *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

[22] Order No. 636 at p. 30,939 (emphasis added).

shippers to release their firm transportation capacity, providing shippers new rights to access additional receipt and delivery points under their contracts, granting shippers the ability to segment their capacity, and creating a new secondary market for transportation capacity. Interstate pipelines were also required to take steps to encourage the creation of market centers across the grid and to make it easier for customers to transact across multiple pipelines.[23] In Order No. 637,[24] issued in 2000, the Commission expanded the flexibility provided to shippers.[25]

While the highly competitive interstate natural gas market created by Order Nos. 636 and 637 has been beneficial to the market as a whole, it has increased the business risks of the interstate pipelines in several inter-related ways:

a. <u>Gas-on-Gas Competition</u>

The flexible receipt and delivery point and segmentation rights given to shippers in furtherance of an integrated transportation network allow shippers greater flexibility to choose among transportation providers, increasing a pipeline's risk of reduced contract

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[23] Order No. 636 promulgated a new regulation, 18 C.F.R. § 284.7(b)(3), prohibiting pipelines to include provisions in their tariffs that inhibit the development of market centers. In Order No. 636-C, the Commission noted that Order No. 636 had led to a substantial increase in the number or market centers in furtherance of the Commission's goal of "of opening up the pipeline grid to form a national gas market for gas sellers and gas purchasers to meet in the most efficient manner," and that "[t]hese market centers provide a variety of services that increase the flexibility of the system and facilitate connections between gas sellers and buyers," including "wheeling, parking, loaning, and storage. Order No. 636-C at p. 61,767.

[24] *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC, 428 F.3d 255* (D.C. Cir. 2005).

[25] For example, the Commission required pipelines to allow replacement and releasing shippers in capacity release transactions to each choose their own primary points in segmented releases to create competition between released capacity and the pipeline's sale of its own capacity. *See* Order No. 637-A at p. 31,594. The Commission further implemented policies revising the right of first refusal process, developing scheduling equality for released capacity, codifying segmentation rights and flexible point rights, changing requirements related to imbalance services and operational flow orders, and modifying requirements regarding retention of penalty revenues.

demand and throughput. This flexibility also allows shippers to source their natural gas from different supply areas which could lead to the devaluation of pipeline capacity from less desirable supply basins. For example, the proliferation of shale gas, particularly in the Marcellus and Utica basins, has changed the flow of gas on some pipeline systems and resulted in changes in the value of pipeline capacity, which is measured by basis differentials between receipt and delivery. In short, the Commission's objective of providing shippers with the flexibility to use pipeline systems to increase their competitive options has been fulfilled. The corollary to the increase in shipper competitive options, however, is increased pipeline risk.

b. Pipeline-on-Pipeline Competition

The Commission has actively promoted pipeline-on-pipeline competition through its certificate policies. In response to concerns from incumbent pipelines that proposed new pipelines or expansions would result in loss load, the Commission generally has concluded that new pipelines "benefit consumers through increased competition," even if competition results in negative impacts on incumbent pipelines.[26] As a result, pipelines face the constant risk of competition from new transportation alternatives, which can place contract renewals by their customers at risk and/or further devalue their capacity, both of which would result in decreased revenues.

c. Pipeline-on-Shipper Competition (Capacity Release)

Capacity release requires pipelines to compete with their own shippers to sell their capacity. Marketers and asset managers can bundle released capacity with a gas purchase or sale and offer an attractive package of services that pipelines cannot offer. Shippers can

[26] *Certification of New Interstate Natural Gas Facilities*, Notice of Inquiry, 163 FERC ¶ 61,042 at P 29 (2018).

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

release their capacity on a short-term basis at prices higher than the pipeline's maximum applicable rate, while pipelines cannot charge more than their maximum applicable rate for their short-term firm and interruptible services.[27] This places pipelines at a disadvantage in generating revenues from sales in short-term markets.

All of these forms of increased competition have resulted in pipelines offering an increasing level of rate discounts effectuated through discounted recourse rates and negotiated rates. In the ten years from 2008 to 2018, maximum recourse rate contracts dropped from 64.4% of interstate pipelines' transportation revenue to only 41.7% of revenues. For these same years, negotiated rate contracts grew to account for 45.7% of revenues, so that nearly half of all interstate pipeline transportation revenues are derived from negotiated rate customers. Discounted rates declined slightly from 16.9% in 2008 to 12.6% in 2018. In total, 58.3% of interstate pipelines' transportation revenues in 2018 were derived from negotiated rate and discounted rate customers.[28]

2. Interstate Pipelines Face Risks Related to Delay and Completion of Expansion Projects.

Natural gas pipelines are facing an increased risk of construction delay and cost overruns due to increased litigation and state challenges to FERC-approved projects.[29]

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[27] *See Promotion of a More Efficient Capacity Release* Market, 123 FERC ¶ 61,286 at PP 30-71 (2008) (removing price cap on short-term capacity releases).

[28] See Initial Comments of Boardwalk Pipeline Partners, June 26, 2019, Docket No. PL19-4. The pipeline transportation revenue is derived from FERC Form 2 data 2008 to 2018, pages 300-301 at Line 10, Col. (h), and page 313, Line 2, Cols. (b) and (d). Revenue at maximum rate is calculated by taking total transportation revenue and subtracting negotiated and discounted rate revenue.

[29] Among pipeline project that are facing or have faced substantial delays are the Atlantic Coast Pipeline, see Dominion Energy, *Dominion Energy Releases Statement Regarding Atlantic Coast Pipeline*, News Release (Feb. 26, 2019), *available at* https://news.dominionenergy.com/2019-02-26-Dominion-Energy-Releases-Statement-Regarding-Atlantic-Coast-Pipeline; the Mountain Valley Pipeline, *see* Reuters, *EQM says 'unlikely' to complete Mountain Valley natgas pipe in 2019* (Apr. 30, 2019); and Millennium Pipeline's Valley Lateral Project, *see* Reuters, *U.S. approves startup of N.Y. Millennium Valley lateral natural gas pipe* (July 9, 2018).

Delays resulting from litigation have the potential to upset the economics of a project by increasing construction costs and potentially requiring payments to shippers for in-service delays. Denials of certain permits by states or other federal agencies have the potential to block a project altogether, despite a determination by the Commission that the project is required by the public convenience and necessity.[30] Blocked projects and litigation have the potential to strand substantial capital investments, since the pipeline has typically already ordered or secured long-lead time items before the litigation began. The increase in opposition to natural gas pipeline expansions and the potential delays or inability to complete expansion projects due to this opposition have increased pipeline owners' business risk. The Commission must consider this risk when determining appropriate ROEs.

3. Interstate Pipelines Face Business Risk Resulting from Regulatory Uncertainty.

Interstate pipelines face additional risk due to investor perception of increased regulatory uncertainty. The perceived stability of the regulatory environment directly affects an investor's decision regarding both whether to allocate capital into the sector and the return required to invest in a company in that sector. Recent Commission initiatives have heightened the investment community's perception of regulatory instability in the interstate pipeline sector. For example, in 2018 the Commission issued a new policy statement that eliminated the income tax allowance for interstate pipelines owned by Master Limited Partnerships ("MLPs"). The impacts of the newly-announced policy

[30] See, e.g., Constitution Pipeline, News Release, *Constitution Pipeline Challenges Decision by New York State to Block Federally Approved Pipeline* (May 16, 2016).

statement led to the loss of billions of dollars in the market capitalization of companies owning interstate pipelines.[31]

The Commission also initiated a process in response to the Tax Cuts and Jobs Act's corporate tax rate reduction that required all interstate pipelines to file a Form No. 501-G. The Form No. 501-G required pipelines to use a 10.55% benchmark ROE in the form, which coupled with the uncertainty over the outcome of those proceedings, caused investors tremendous concern. The Commission subsequently set the rates of six pipelines for investigation pursuant to Section 5 of the NGA.[32] Section 5 investigations create regulatory uncertainty and revenue instability. The Commission's approach to Section 5 enhances the asymmetrical business risk faced by interstate pipelines because pipelines are at risk for low returns during unfavorable market conditions with little or no ability to offset that risk by capturing higher returns during favorable market conditions. The Commission should consider the current contracting trends and the increased level of discounted and negotiated rate contracts when deciding how to exercise its NGA section 5 authority, and account for the risk of uncertainty created by these types of regulatory mandates and rate investigations in establishing gas pipeline ROEs.

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[31] *See, e.g.,* Comments of Boardwalk Pipeline Partners, LP, Docket No. RM18-11-000 (Apr. 25, 2018) (demonstrating $12 billion loss in market capitalization across nine companies following the Commission's actions); Request for Clarification or Rehearing and Request for Expedited Action of Dominion Energy, Inc. at 3, Docket No. PL17-1-000 (Mar. 30, 2018) (estimating that in the ten trading days following the Commission's announcement, MLPs lost nearly $30 billion in market value.)

[32] *See Stagecoach Pipeline & Storage Company LLC* 166 FERC ¶ 61,199 (2019); *Southwest Gas Storage Co.*, 166 FERC ¶ 61,117 (2019); *Panhandle Eastern Pipe Line Co., LP*, 166 FERC ¶ 61,032 (2019); *Northern Natural Gas Co.*, 166 FERC ¶ 61,033 (2019); *Bear Creek Storage Company, L.L.C.*, 166 FERC ¶ 61,034 (2019); and *East Tennessee Natural Gas, LLC*, 165 FERC ¶ 61,198 (2018).

4. Interstate Pipelines Face Business Risk Related to the Commission's Pipeline Abandonment Policies.

Section 7(b) of the NGA prohibits a pipeline from abandoning facilities or service without Commission authorization.[33] The Commission has utilized this authority to deny requests by pipelines to abandon uneconomic pipeline facilities if the shippers utilizing the facilities object to the proposed abandonment, even if those shippers utilize only a small proportion of the capacity on the facilities.[34] The Commission has denied abandonment even if continued service would make it difficult for the pipeline to earn a reasonable return based on the rationale that the pipeline has the opportunity to file a rate case and allocate costs to the underutilized facilities. Yet, the ability to raise rates and reallocate costs associated with an uneconomic pipeline or a segment thereof is not a viable solution.

C. <u>Proposed Modification to Guidelines for Proxy Group Composition.</u>

One of the fundamental concerns expressed by the Commission in the NOI related to "the appropriate guidelines for proxy group composition."[35] The Commission rightfully asks "[c]an the Commission continue to construct proxy groups of sufficient size for natural gas and oil pipeline companies . . . particularly considering the increased amount of merger and acquisition activity involving master limited partnerships (MLPs) and the multiple recent conversions of MLPs to C-corporations?"[36] INGAA agrees with the Commission's concerns and, in this section, provides the Commission with proposals that would allow the Commission to consistently and reliably construct a representative proxy group of

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[33] 15 U.S.C. § 717f(b).

[34] *See, e.g.*, *Gulf South Pipeline Company, LP*, 145 FERC ¶ 61,236 (2013) (denying abandonment of uneconomic facilities following objection by firm shippers). The Commission has denied abandonment applications even when the abandonment is opposed only by interruptible shippers. *See Northern Natural Gas Co.*, 135 FERC ¶ 61,048, at P 4, 35 (2011) (*MOPS*) (denying abandonment despite the absence of firm contracts on the pipeline).

[35] NOI at P 34.

[36] *Id.* at P 34 (D11).

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sufficient size for interstate gas pipeline companies. The Commission has wrestled with the composition of the gas pipeline proxy group in the past and has adjusted its policies on eligibility for membership in the proxy group in a flexible and pragmatic manner. INGAA supports the continuation of that approach.

Through both case law and the Commission's Proxy Group Policy Statement,[37] the Commission established the following eligibility criteria for inclusion of an entity in a gas pipeline proxy group:

1. The company or MLP's stock/units must be publicly traded.[38]
2. The company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service such as Value Line.[39]
3. Gas pipeline operations must constitute a high proportion of the company's business.[40]
4. The company must have an investment credit rating of BBB- or better (S&P).[41]
5. The company must not have cut or reduced its dividend in the latest six month to one year period – at least six months.[42]
6. The company cannot be involved in merger or acquisition activity in the latest six month to one year period.[43]

INGAA requests that the Commission retain its historic flexibility in the composition of the gas pipeline proxy group. The Commission should: (1) allow the

[37] 123 FERC ¶ 61,048 (2008).
[38] *Id*. at P 8.
[39] *Id*.
[40] *Id*.
[41] *See Portland Natural Gas Transmission System*, 134 FERC ¶ 61,129, at n. 301 (2011) ("In any event, we agree with the ALJ's decision to exclude El Paso Corporation on the grounds that its credit rating was not investment grade during the relevant time period.").
[42] *See Kern River Gas Transmission Company*, 129 FERC ¶ 61,240, at P 88 (2009) (explaining that NiSource's dividend cut within the six-month period used for the DCF analysis "provides an independent ground requiring exclusion.").
[43] *See e.g., Kern River Gas Transmission Company*, 126 FERC ¶ 61,034 at P 81 (2009) (excluding Enterprise, in part, because "its financial profile was affected by a merger.").

inclusion of comparable risk companies in proxy groups even if such companies otherwise may not meet the "high proportion" of gas pipeline operations threshold; and (2) shorten the period of time during which companies that have undergone recent merger activity are excluded, given the dynamic capital markets and the realities of the industry.

The Commission should utilize the widely-accepted financial metric, "beta", to assist in determining risk comparability. FERC should expand the potential proxy group universe by allowing the inclusion of companies with significant natural gas pipeline assets and similar betas into gas pipeline proxy groups, because the financial community considers companies with similar betas to have similar risks. Together, these changes will ensure that interstate natural gas pipeline companies and FERC can construct proxy groups of comparable risk companies that are representative of the industry.

1. The Available Proxy Group Members that Meet the Commission's Stated Criteria Have Been Reduced.

Compiling a "representative" proxy group has become increasingly difficult over the past few years. Consolidation in the industry has removed many "pure play" natural gas pipeline companies, which has eliminated many potential entities eligible for inclusion in gas pipeline proxy groups. Recent Commission actions, discussed in more detail below, have also spurred increased consolidation of MLPs, which has eliminated entities which have been historically included in proxy groups.

Consolidation within the midstream segment has increased since 2004, with many interstate natural gas pipeline companies now included in larger energy conglomerates which own a variety of energy-related assets in addition to natural gas pipelines. These consolidations have created entities with diversified energy holdings, but many of these organizations, while not solely focused on interstate natural gas pipelines, carry significant

FERC-regulated pipeline assets, including oil pipelines, or intrastate pipelines regulated by state commissions.

While the consolidation in the midstream segment is a natural effect of efficient capital markets, the result is fewer entities eligible for inclusion in a proxy group pursuant to a requirement that a "high proportion" of assets or revenues devoted to interstate natural gas pipeline operations. This requirement is unique to FERC-regulated natural gas pipelines as FERC-regulated electric utilities are not subject to a similar "high proportion" requirement. The effect of the increasing consolidation in the industry is that entities which own a significant number of FERC-regulated interstate pipelines may not qualify for inclusion in the proxy group under the Commission's current approach because they have a larger proportion of non-interstate gas pipeline holdings. Rigid application of the Commission's current requirements would exclude the majority of interstate pipelines from proxy groups. The Commission's development of a proxy group policy should seek opportunities to broaden the proxy group criteria to include as many interstate pipelines as possible.

2. Recent Regulatory Actions Have Further Reduced the Number of Potential Proxy Group Members.

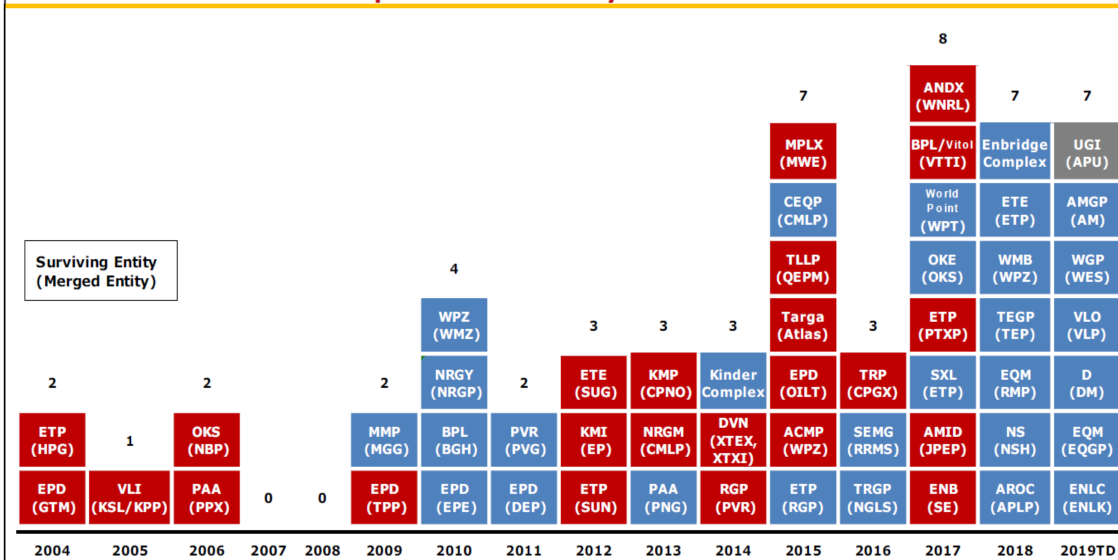
In response to the U.S. Court of Appeals for the District of Columbia Circuit's remand of *United Airlines, Inc., et al. v. Federal Energy Regulatory Commission*,[44] and after significant comments were filed in response to a Notice of Inquiry,[45] the Commission

[44] 827 F.3d 122 (D.C. Cir. 2016). In *United Airlines, et al. v. FERC*, the D.C. Circuit concluded that there appeared to be a double recovery of taxes for MLPs because certain parties in that case argued that an income tax component was implicitly included in the DCF calculation for MLP proxy group members. The D.C. Circuit remanded the case to the Commission and required the Commission to justify that there was no double recovery of taxes.

[45] *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs*, 157 FERC ¶ 61,210 (2016) ("Income Tax NOI").

issued a policy statement on March 15, 2018 ("MLP Tax Policy Statement") removing the income tax allowance from MLPs' costs of service.[46] This policy change sent waves throughout the midstream segment as numerous partnerships formerly organized as MLPs were consolidated and brought back under corporate ownership. These MLPs include Tallgrass Energy Partners, Williams Partners, Enbridge Energy Partners, Spectra Energy Partners, Boardwalk Pipeline Partners, and Dominion Energy Midstream Partners. Many of these entities previously were included in proposed proxy groups in various rate cases but are now no longer available. Wells Fargo, as part of its May 2019 Midstream Monthly Report, produced the chart shown below, highlighting the numerous midstream consolidations that have taken place from 2004 to present and the accelerated nature of those consolidations over time:

Exhibit 26. Midstream Simplification Activity Has Accelerated



Note: Only includes mergers of public companies. Gray boxes represent pending transactions.
Note: WGP is the surviving entity from the WES/WGP simplification, but the company changed their ticker to WES. Also, AMGP is the surviving entity from the AM/AMGP simplification, but the company changed their ticker to AM.
Note 1: Following NRGM's merger with CMLP, the surviving entity (i.e. NRGM) was renamed CMLP.
Note 2: Blue boxes represent transactions within the same family of companies (i.e., roll-ups, buy-ins).
Source: Company reports and Wells Fargo Securities, LLC

[46] *Revised Policy Statement on Treatment of Income* Taxes, 162 FERC ¶ 61,227 (2018).

As illustrated, over 40% of the consolidations reflected in Wells Fargo's analysis occurred between 2017 and year-to-date 2019, after the Commission's issuance of the Income Tax NOI.

The recent consolidation of MLPs is illustrated by the proxy group addressed in Order No. 849, which implemented a one-time review of pipeline returns in light of the reduction in corporate tax rate resulting from the Tax Cuts & Jobs Act and the MLP Tax Policy Statement.[47] In Order No. 849, the Commission proposed the use of a new Form No. 501-G that included a benchmark ROE of 10.55%, which the Commission explained was the last approved ROE from *El Paso Natural Gas Co*.[48] The *El Paso* proxy group supporting the 10.55% ROE consisted of the following:

	El Paso DCF Result
Spectra Energy Corp	11.08%
Boardwalk Pipeline Partners, LP	10.41%
Spectra Energy Partners, LP	10.39%
TC Pipelines, LP	10.89%
Williams Partners, LP	10.55%
Median	10.55%

Four of the five members of the *El Paso* proxy group no longer exist. One (Spectra Energy Corp) was consolidated via merger[49] and the remaining three were consolidated after the Commission's issuance of its MLP Income Tax Policy Statement. In a press release announcing the consolidation of Spectra Energy Partners, Enbridge identified one of the benefits of the consolidation as addressing the "risks related to FERC MLP tax allowance

[47] 164 FERC ¶ 61,031 (2018).
[48] *El Paso Natural Gas Co.*, Opinion No. 528, 145 FERC ¶ 61,040, at P 642 (2013), *reh'g denied*, Opinion No. 528-A, 154 FERC ¶ 61,120 (2016) ("*El Paso*").
[49] Enbridge Inc. (September 6, 2016). *Enbridge and Spectra Energy to Combine to Create North America's Premier Energy Infrastructure Company with C$165 Billion Enterprise Value* [Press release]. Retrieved from https://www.enbridge.com/media-center/news/details?id=122530&lang=en

elimination."[50] Williams Partners LP's public equity was acquired by Williams, who explained in its announcement of the transaction that it "considered a number of alternatives relating to the FERC ruling and determined that the transaction described herein is in the best interest of Williams' shareholders and Williams Partners' public unitholders."[51] Loews Corporation purchased its subsidiary Boardwalk Pipeline Partners' outstanding public shares, and noted in an earnings conference call that, "as a result of the decision in March of this year by the Federal Energy Regulatory Commission, we began to rethink the efficacy and wisdom of the MLP structure for Boardwalk," and "[a]fter careful consideration of all options, we determined that exercising our call provision was in the best interest of Loews' shareholders."[52] Accordingly, the proxy group relied on to support the ROE in the Form No. 501-G proceedings no longer exists today, largely as a result of the Commission's MLP Income Tax Policy Statement.

3. Opportunities Exist to Shore Up and Bolster the Diminishing Proxy Group.

The Commission should expand its proxy group eligibility criteria by continuing to consider additional energy entities of comparable risk even if those entities do not meet the "high proportion" of natural gas pipeline threshold. This flexibility would allow for the potential inclusion of companies in the proxy group that hold significant amounts of natural gas pipeline capacity, but which do not meet the "high proportion" criteria due to other

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[50] Enbridge Inc. (May 17, 2018). *Enbridge Announces Simplification of Corporate Structure with Proposals to Acquire All of the Outstanding Sponsored Vehicle Equity Securities*. Retrieved from https://www.enbridge.com/media-center/news/details?id=123513&lang=en.

[51] The Williams Companies Inc. (May 17, 2018). Williams Announces Agreement to Acquire All Public Equity of Williams Partners L.P. [Press release]. Retrieved from https://investor.williams.com/press-release/williams/williams-announces-agreement-acquire-all-public-equity-williams-partners-lp.

[52] Loews Corporation, Q2 2018 Earnings Conference Call (July 30, 2018), *available at* https://www.nasdaq.com/aspx/call-transcript.aspx?StoryId=4191995&Title=loews-corporation-l-ceo-james-tisch-on-q2-2018-results-earnings-call-transcript.

assets in their portfolios. The flexibility to include these companies in a gas pipeline proxy group would make the proxy group more representative of the business risks associated with the interstate pipeline industry. As discussed below, INGAA proposes a methodology that will ensure that all companies included in the proxy group are comparable risk to other entities that traditionally meet the Commission's criteria.

The Commission also should consider other flexible approaches to determining proxy group criteria. For example, the Commission should not exclude a Canadian company that has significant U.S. interstate natural gas pipeline assets from inclusion in the proxy group if its risk profile is comparable to that of an interstate natural gas pipeline company[53]. This would allow for the inclusion of Enbridge and TC Energy, both of which now have significant U.S. natural gas pipeline assets. The Commission also should shorten the period used to exclude a company from a proxy group due to merger activity. The principal concern with respect to mergers is that there may have been insufficient time for the market to adjust for the merger activity and for these companies to reflect their new normalcy and be representative of the overall pipeline industry. This adjustment process should take no longer than six months after a transaction closes. Therefore, a company should be eligible for inclusion in a proxy group six months after a merger transaction closes.

[53] *See Portland Natural Gas Transmission System*, 134 FERC ¶ 61,129, at P 224 (2011) ("As to TransCanada, the ALJ excluded it because although over 90 percent of TransCanada's operating income is derived from natural gas pipeline operations, only 51 percent of that is from U.S. pipeline operations and the non-U.S. assets are subject to a different regulatory structure. As we did in Opinion No. 486-B, we find that this regulatory structure renders TransCanada less comparable to U.S. pipelines that are regulated by the Commission, and thus approve the ALJ's decision to exclude TransCanada from the proxy group."); *El Paso*, 145 FERC ¶ 61,040, at PP 604, 626 (2013) (affirming ALJ's exclusion from the proxy group of TransCanada Corporation based on the finding that "TransCanada Corporation is subject to the vagaries of Canadian regulation and Canadian capital markets, thereby making it difficult to establish comparable risk.").

While the aforementioned adjustments to the Commission's current criteria for inclusion in the gas pipeline proxy group will be helpful in expanding the eligible candidates for inclusion, INGAA believes that additional measures are needed to ensure that the Commission, pipelines and other participants in rate proceedings are able to compile a proxy group that is representative of the interstate pipeline industry and, by definition, includes entities of comparable risk.

a. The Commission Should Utilize the Financial Metric "Beta" to Supplement Proxy Groups.

INGAA proposes the use of the widely used and reported financial metric, "beta", as an added measure of analysis that would provide opportunities to include companies that own interstate pipeline assets that otherwise would not be included in a proxy group due to the Commission's current criteria. In finance, beta "measures a security's volatility in relation to that of the market as a whole and is generally computed from a linear regression analysis based on past realized returns over some past time period."[54] To measure beta, a comparison is made between the movements in price of a given stock and a selected market index. For example, Thomson Reuters benchmarks stock price movements against movements of the S&P 500 in the development of its reported betas. Betas are analyzed over time (1-, 3- or 5-years) and can be measured on a daily, weekly, or monthly basis. When analyzing beta, the beta for the market as a whole is always 1.00, by definition. Any security with a beta above 1.00 is indicated to have risk that is higher than the average of the analyzed market. Any security with a beta below 1.00 is indicated to have less risk than the average of the analyzed market. An investor can utilize beta to risk-rank individual securities within an industry and also can utilize beta to compare the

[54] Roger A. Morin, New Regulatory Finance at 70 (Public Utilities Reports, Inc.) (2006) ("Morin").

relative risk of one industry against another. When analyzing beta, one final consideration is the tendency of beta to converge to 1.00 over time. Doctor Roger A. Morin, author of *New Regulatory Finance*, notes the following regarding this convergence:

> The regression tendency of betas to converge to 1.00 over time is very well known and widely discussed in the financial literature. Well-known college-level finance textbooks routinely discuss the use of adjusted betas.[55]

Dr. Morin continues:

> The tendency of true betas not only to vary over time but to move back toward average levels is not surprising. A company whose operations or financing make the risk of its stock divergent from other companies is more likely to move back toward the average than away from it. Such changes in beta values are due to real economic phenomena, not simply to an artifact of overly simple statistical procedures.
>
> Because of this observed regressive tendency, a company's raw unadjusted beta is not the appropriate measure of market risk to use. Current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Historical betas, whether raw or adjusted, are only surrogates for expected beta. The best of the two surrogates is adjusted beta.[56]

Adjusted beta is calculated by assigning a 2/3 weight to the raw beta and assigning a 1/3 weight to the market beta of 1.00. The formula for adjusted beta is then:

$$\text{Adjusted } \beta = (\text{Raw Beta} * 0.66) + (\text{Market Beta} * 0.33)$$

b. <u>Comparison of Betas between Energy Sub-Industries Highlights Differences in Risk</u>

Beta can be utilized to compare risk between industries and between companies within the same industry. Within the overall energy industry, there are various unique sub-industries. Value Line segments the 1,700 stocks in its universe into 97 industry groups. For rate-regulated companies, Value Line classifies as follows: electric utilities

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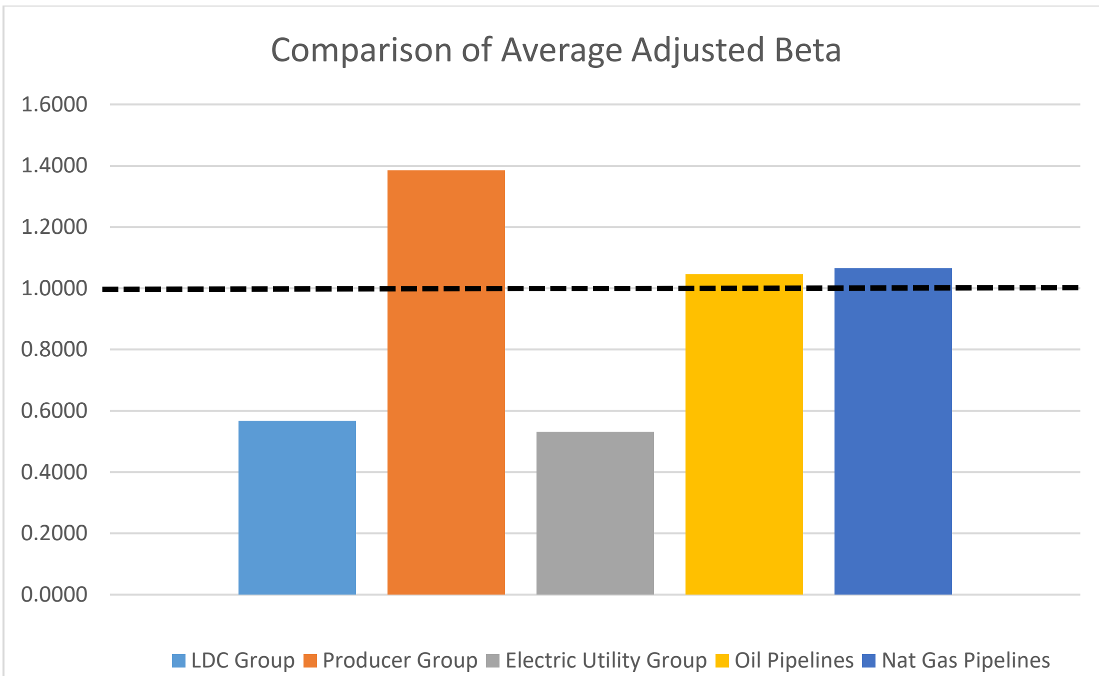
55 *Id.* at 72.
56 *Id.* at 73.

geographically into three groups (i.e., East, Central, West), natural gas into two groups (diversified and utility), oil/gas distribution, and pipeline MLPs. The natural gas pipelines familiar to most are found in the oil/gas distribution and pipeline MLP groups. INGAA analyzed the betas of various groups within the energy industry, including natural gas pipelines, local distribution companies ("LDCs"), natural gas producers, electric utilities and oil pipelines. The average adjusted betas for these groups are reflected in the chart below:



Source: Adjusted 5-Year Monthly Betas
Thomson Reuters
June 3, 2019

The average adjusted betas for the producer, oil pipelines, and natural gas pipelines are above 1.00, indicating a higher-than-market risk for these sub-industries. The LDC and electric utility sub-industries carry an average adjusted beta significantly below 1.00, indicating that these sub-industries are much less risky than the overall market. These beta findings recognize the higher risks of pipelines relative to other groups such as electric utilities and LDCs.

c. Using Beta as a Benchmark to Proxy Group Inclusion

Not only can beta be utilized to distinguish interstate pipelines from other energy sub-industries, but betas also can be used to increase the available companies for proxy group inclusion. INGAA does not propose to use betas as a replacement for the Commission's current proxy group criteria either as currently constituted or with the aforementioned adjustments proposed by INGAA to the "high proportion" and merger criteria. Instead, INGAA submits that betas should be used as a tool to supplement the proxy group criteria. INGAA proposes that the parties select a "foundation" group which meets the Commission's current proxy group eligibility criteria. Each party supporting a foundation group would be required to demonstrate how each member in the group meets the Commission's criteria. As an example, a foundation group may consist of the following companies:

	Gas Pipeline Operations Asset Percentage (2018)	Gas Pipeline Operations Revenue Percentage (2018)
EQM Midstream Partners, LP	96.95%	96.95%
Kinder Morgan Inc.	70.44%	63.66%
TC Pipelines, LP	100.00%	100.00%
Williams Companies Inc.	66.33%	68.80%

Source: SEC 10-K filings for FY 2018

While this foundation group includes representative gas pipelines, they are too small to meet the Commission's preferred proxy group size of five or more and in total does not represent a significant level of FERC-regulated gas pipeline companies, capacity or assets, as shown by the following table:

	Percentage of FERC Form 2 Filers	Percentage of Capacity	Percentage of Utility Plant
Foundation Group	27.9%	37.4%	35.6%

This minimal representation reflects the insufficiency of the current proxy group criteria as, depending on the measure, at least 60% of interstate pipeline companies remain disqualified from inclusion and unrepresented. A proxy group is meant to create a group of pipelines "with *corresponding risks* to set a range of reasonable returns" for the natural gas pipeline whose rates are subject to review, and the Commission's intent has been to "make those proxy groups *more representative of the business risks* of the regulated firm whose rates are at issue."[57]

The Commission should consider, and pipelines should be permitted to use, financial betas as a supplement to determine additional candidates eligible for proxy group inclusion. Use of betas would allow the Commission to increase the proxy group members to incorporate a greater percentage of interstate pipelines and render the proxy group more representative of the pipeline whose ROE is being established. The first step in such an analysis would be to create a beta range for the foundation group companies. The beta range for the example "foundation" group would be as follows:

	Adjusted 5-Year Monthly Beta
EQM Midstream Partners, LP	1.017
Kinder Morgan Inc.	0.896
TC Pipelines, LP	0.765
Williams Companies Inc.	1.427
High	1.427
Low	0.765
Average	1.026

Source: Thomson Reuters
June 3, 2019

Using this beta range, a party could propose adding additional entities to the proxy group whose betas fall within the established "foundation beta range". Such party would

[57] Proxy Group Policy Statement at PP 7, 49.

have the burden to support the inclusion of any entity into the proxy group. For example, a party could propose that other energy entities, that own interstate natural gas pipelines and whose beta falls within the range of the foundation proxy group, be added to the foundation proxy group. By expanding the proxy group to include pipeline companies with a beta in the foundation beta range (0.765 to 1.427), the companies highlighted in yellow in this example could be proposed to be included in the proxy group:

Additional Pipelines for Inclusion in Proxy Group	Adjusted 5-Year Monthly Beta
Enbridge Inc	0.910
Enable Midstream Partners, LP	1.195
Energy Transfer, LP	1.436
TC Energy Corp	1.031
Tallgrass Energy, LP	0.903

Source: Thomson Reuters
June 3, 2019

If these companies were added to the example foundation proxy group reflected above, the expanded proxy group's percentage representation of natural gas pipelines would be:

	Percentage of FERC Form 2 Filers	Percentage of Capacity	Percentage of Utility Plant
Foundation Group	27.9%	37.4%	35.6%
Expanded Proxy Group	51.1%	77.2%	75.2%

Source: Derived from EIA and FERC Form No. 2 data

The result of including companies with commensurate risks to natural gas pipelines as measured by betas is a larger and more representative proxy group for the development of a just and reasonable return on equity.

The use of beta as a supplement to determine additional candidates eligible for proxy group inclusion is a just and reasonable approach to addressing the ongoing consolidation of the industry. Using the range of betas of the foundation group as a band for inclusion of other companies in the proxy group provides reasonable assurance that only companies of comparable risk are included in the proxy group. Parties in rate cases will continue to have the ability to propose or oppose the inclusion of any entity. The beta metric simply provides a widely-available and used quantitative factor to help determine a representative proxy group and a just and reasonable return on equity.

4. Proxy Group Flexibility Is Consistent with Historic Commission Practice.

The Commission first addressed the problem of the shrinking natural gas pipeline proxy group in a section 4 rate case proceeding of Williston Basin Interstate Pipeline Company ("Williston II").[58] The Commission relaxed its requirement that, for a corporation to be included in a proxy group, the corporation's natural gas pipeline business must account for at least 50 percent of the corporation's assets or operating income.[59]

The Commission next addressed the proxy group issue, in *High Island Offshore System, L.L.C.* ("*HIOS*"),[60] and *Kern River Gas Transmission Company* (Opinion No. 486 or "*Kern River*").[61] The *Williston II* proxy group had shrunk to only six corporations by that time.[62] Of the remaining six, El Paso and Williams were in financial difficulties that resulted in dividend cuts which lowered their ROEs to such a low level rendering them

[58] *Williston Basin Interstate Pipeline Company*, 104 FERC ¶ 61,036 at P 35, n. 46 (2003).
[59] The Commission approved a proxy group based on the corporations listed in the Value Line Investment Survey's list of diversified natural gas firms that own Commission-regulated natural gas pipelines, without regard to what portion of the company's business comprised pipeline operations. The proxy group approved in that case included: Coastal Corporation ("Coastal"), Columbia Gas Transmission Corporation ("Columbia"), El Paso Energy Corporation ("El Paso"), Enron Corporation ("Enron"), Equitable Gas Company ("Equitable"), Kinder Morgan, Incorporated ("Kinder Morgan"), National Fuel Gas Supply Corporation ("National Fuel"), Questar Corporation ("Questar"), and Williams Companies, Inc. ("Williams"). Only Equitable, Kinder Morgan, National Fuel and Williams remain as publicly traded companies today.
[60] 110 FERC ¶ 61,043, *reh'g denied*, 112 FERC ¶ 61,050 (2005).
[61] 117 FERC ¶ 61,077 (2006), *reh'g pending.*
[62] Columbia and Coastal had been acquired by other companies and were no longer publicly traded, and Enron had filed for bankruptcy.

unrepresentative excluding them from proxy group consideration.[63] The remaining proxy group companies were Equitable, Kinder Morgan, National Fuel, and Questar. The Commission then observed that three of the four eligible companies for proxy group consideration derived more revenue from the distribution business than the pipeline business (Equitable, National Fuel, and Questar). In order to account for the generally higher risk profile of interstate pipeline operations relative to distribution companies, the Commission increased the pipeline's return on equity by 50 basis points (0.5%) above the median of the four-member proxy group. This adjustment was designed to reflect the difference in the risk profile between distribution companies and pipelines while maintaining members of the proxy group, emphasizing that a sufficiently-sized proxy group is a critical component of the DCF analysis. In *HIOS*, the Commission did not allow MLPs to be included in the proxy group, as proposed by the pipelines.

In Opinion No. 486-B, issued in the *Kern River* proceeding, the Commission approved the use of MLPs in the proxy group for the first time.[64] The *Kern River* proxy group included two corporations, Kinder Morgan and National Fuel, and three MLPs, Northern Border Partners, L.P., TC Pipelines, L.P., and Kinder Morgan Energy Partners ("KMEP"). The Commission found that a proxy group with three or four members was too small and stated a preference for proxy groups of at least five members. The Commission added that a larger proxy group could result in greater statistical accuracy, but only if the additional members were appropriately included in the proxy group as representative of the risk of the interstate natural gas pipeline industry.

[63] *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 at P 118 (2005) ("*HIOS")*. *Kern River Gas Transmission Company*, *Opinion and Order on Initial* Decision, Opinion No. 486, 117 FERC ¶ 61,077 at PP 140-141 (2006).

[64] *Kern River Gas Transmission Company*, Opinion No. 486-B, 126 FERC ¶ 61,034 (2009).

In addition to allowing MLPs into the proxy group, Opinion No. 486-B also allowed the inclusion of proxy group entities that did not meet the Commission's 50% natural gas pipeline criteria. The Commission approved KMEP's inclusion in the proxy group because its oil and natural gas pipeline components resulted in a transmission function of 70 percent which significantly exceeded the 50 percent combined threshold standard previously discussed and no other component predominated.[65] The Commission found that although KMEP had been included in oil pipeline proxy groups, it could also be included in a gas pipeline proxy group as the firm had a balanced investment in both businesses.

The Commission has when necessary employed a flexible approach in determining proxy group eligibility that appropriately represents the business risk of the interstate natural gas pipeline industry. In 2008, many gas pipeline assets were being transferred to publicly traded MLPs, whose business was narrowly focused on pipeline activities. In the Proxy Group Policy Statement, the Commission determined that MLPs could be included in the proxy group because it made proxy groups more representative of the business risks of regulated pipelines.[66]

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[65] KMEP was an MLP included in Value Line's list of diversified natural gas companies, but KMEP's natural gas pipelines accounted for only 35 percent of its total assets as of the end of 2004. KMEP also owned oil and product pipelines which accounted for another 35 percent of its assets, CO2 pipelines which accounted for 14 percent of its assets, and terminal facilities which accounted for the remaining 15 percent. KMEP had approximately equal amounts of operating income from its natural gas pipelines and oil pipelines. Its income from CO2 pipelines and terminals was about half the amount of its gas and oil pipelines. KMEP was not involved in gas distribution, exploration and production, or trading and marketing activities during 2004. The Commission concluded that the oil pipeline component of a diversified natural gas company would increase somewhat the firm's overall risk, primarily due to the oil pipeline industry's perceived overall greater exposure to competition at that time.

[66] Proxy Group Policy Statement at P 49 (2008).

5. The Beta Concept Provides A Long-Term Solution to Proxy Group Eligibility.

The use of the financial metric "beta" allows for a measured approach to address the shrinking proxy group issue. The use of beta is consistent with the historic instances described above in which the Commission addressed the shrinking of proxy groups through reasonable modifications of the proxy group criteria to include additional members that are aligned with the pipeline's risk. Tying any proxy group solution to specific companies will never yield a long-term solution due to the ongoing potential that specific companies will disappear following a merger, consolidation, or default. The beta concept proposed by INGAA, in combination with the proposed adjustments to the current criteria, provides for a long-term solution to proxy group eligibility by addressing the requirement for proxy groups to include entities of similar risk without being dependent upon the satisfaction of each of the Commission's criteria for inclusion of specific companies in the proxy group.

D. <u>What Models Are Appropriate to Determine Returns for Natural Gas Pipelines?</u>

1. Should FERC Continue to Rely Solely on DCF, or Use Other Models?

INGAA continues to believe that the DCF methodology should be used to determine gas pipeline ROEs but recognizes that the performance of the DCF model, like the other models discussed in the NOI, is not precise and may be distorted by unusual capital market conditions. INGAA supports the consideration of other models, modified as reflected herein, to establish allowed ROEs for natural gas pipelines. The consideration of more than one model will tend to mitigate the impact that any anomalous financial conditions may have on the results of any one model. As discussed in more detail below, the Commission should not adopt a formulaic averaging of the models it considers and should retain the flexibility to place appropriate weight on, or exclude, any of the models in light of prevailing financial conditions at that time and the facts and circumstances of each case.

2. Which Models Should Be Considered for Interstate Natural Gas Pipelines?

In the NOI, the Commission discusses three models other than DCF: (1) CAPM, (2) Expected Earnings and (3) Risk Premium. The Commission requests comments on whether one or more of these methods should be used to determine interstate natural gas pipeline ROEs, and what differences between public utilities and interstate natural gas pipelines and oil pipelines would justify using different methodologies to determine their ROEs.[67]

INGAA submits that only the DCF, CAPM and Expected Earnings models should be considered in the determination of natural gas pipeline ROEs.[68] The Risk Premium model cannot be applied to determine sufficiently reliable interstate natural gas pipelines ROEs due to the absence of data required by the model. As the Commission has implicitly acknowledged in the NOI, it would be difficult, if not impossible, to implement the Risk Premium methodology in interstate natural gas pipeline cases due the lack of stated allowed ROEs in litigated decisions or settlements. The Commission asks (at P 32, Q. B2) how the Risk Premium methodology could be implemented in natural gas pipeline rate cases where there is no history of ROE settlements from which to develop a risk premium study of the type used in Opinion No. 551. In the *MISO* electric proceeding, the Commission approved a Risk Premium analysis submitted by Dr. William Avera on behalf of the MISO

[67] NOI at PP 32, 34.

[68] Although INGAA submits that the Risk Premium methodologies discussed in the NOI are difficult to apply to determine natural gas pipeline ROEs for the reasons discussed herein, parties should be allowed to propose other methodologies for implementing a Risk Premium model in individual rate proceedings.

Transmission Owners. Dr. Avera developed a market risk premium based on an analysis of 75 ROEs authorized by the Commission for electric utilities and applied a standard regression model to determine the relationship between the market risk premium and bond yields to adjust the risk premium.[69] Due to the lack of available FERC-allowed ROEs for interstate natural gas pipelines, a similar analysis cannot be adequately performed to set pipeline ROEs.

In the NOI, the Commission noted that as an alternative to developing a risk premium directly for the company at issue, one can be indirectly developed by conducting a risk premium analysis for the market as a whole, and then adjusting that result to reflect the risk of the company at issue. NOI at P 17. INGAA's expert, Dr. Michael Vilbert of The Brattle Group, explains in his affidavit submitted with these comments why it is not a viable alternative for interstate pipelines. Dr. Vilbert states that, if the Risk Premium model were based upon the whole market, it would require a risk adjustment for the industry relative to the risk of the market as a whole. Beta estimates could be used to demonstrate differences in risk, but use of betas would make the Risk Premium model based upon the whole market very similar to CAPM. Using measures of risk other than beta would be more complex and more subjective and would still leave the Risk Premium model very similar to CAPM. Both the CAPM and the Risk Premium model add a premium for risk to a benchmark interest rate. The CAPM is a theoretical model whose benchmark is a risk-free interest rate and the risk premium is calculated as the product of beta times the market risk premium where beta is a measure of the relative risk of the asset to the market. In comparison, the Risk Premium benchmark interest rate can be relative to any bond yield,

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[69] *Ass'n of Business Advocating Tariff Equity, et al. v. MISO,* 153 FERC ¶ 63,027 at PP 233-35, 252 (2015).

and the risk premium may be calculated using other factors to determine risk. However, this version of the Risk Premium model is very similar to the CAPM because both rely upon the return on the market and a measure of relative risk compared to the market's risk. As stated by Professor Morin, CAPM estimates risk premiums indirectly, whereas the Risk Premium analysis methodology develops risk premiums directly.[70]

In the NOI, the Commission referred to its briefing orders in the *Coakley/MISO* proceedings involving challenges to public utility ROEs under section 206 of the FPA to propose the use of multiple models. Similar to section 5 of the NGA, a challenger to an existing rate under section 206 of the Federal Power Act has a two-prong burden of proof: (1) to show that the existing rate is unjust and unreasonable, and (2) to establish a new, just and reasonable rate. In the *Coakley/MISO* Briefing Orders and in the NOI, the Commission proposed to use the four models discussed above to establish a new just and reasonable ROE under the second prong, but to exclude the Risk Premium model from the determination of whether an existing ROE is unjust and unreasonable under the first prong. Because the Commission proposes to establish a composite zone of reasonableness as part of the first prong analysis, the Commission proposed to exclude Risk Premium from this analysis because unlike the other three models, it produces only a single numerical ROE rather than a range. NOI at PP 24-26.

It is not appropriate to use a different set of models to determine ROEs under sections 4 and 5 of the NGA, or for the different prongs of section 5. Omitting the Risk Premium model from establishing interstate pipeline ROEs resolves the issue the Commission sought to address in the *Coakley/MISO* proceedings by excluding the Risk

[70] Opinion No. 531, at P 247 at n.289, *citing* Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc.) (2006).

Premium method from the first prong of the FPA section 206 analysis. INGAA's approach of excluding the Risk Premium model avoids the inconsistency inherent in the use of a different model group for determining the just and reasonableness of an existing or new ROE.

E. <u>The Commission Should Allow Flexibility in the Weighting of the Different Methodologies.</u>

In the Court's remand in *Emera Maine,* and the post-*Emera Maine* proceedings, the Commission reevaluated the methodologies traditionally used by financial analysts and sought to bring its approach into closer alignment with how investors inform their investment decisions.[71] Recognizing that investors rely on multiple financial models to estimate an expected return on investment, the Commission suggested that it would no longer rely solely on the DCF method, but instead would consider three other traditional methods used by analysts.[72] The Commission further found that each of these methods is based on different financial theories and assumptions used to assess investor expectations.[73] The Commission also recognized the concept of "model risk", the risk that the theoretical assumptions underlying any of the methods may not reflect real-world experience.[74] The Commission stated that "model risk" was the reason the DCF method in the recent past appeared to perform in a manner that was inconsistent with the theory underlying that method.[75]

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[71] *Coakley* Briefing Order at P 15; *MISO* Briefing Order at P 12.

[72] *Coakley* Briefing Order at P 40; *MISO* Briefing Order at P 42.

[73] *Coakley* Briefing Order at PP 34-35; *MISO* Briefing Order at PP 12.*Id.* at PP 34-35.

[74] *Coakley* Briefing Order at P 46; *MISO* Briefing Order at P 47.

[75] *Coakley* Briefing Order at PP 45-46; *MISO* Briefing Order at P 47.

INGAA generally agrees with the underlying premise of the *CoakleyMISO* Briefing Orders that the various financial models used to estimate ROE are based on different theoretical assumptions, and that the validity of these assumptions may depend on capital market conditions at any given time. INGAA also agrees that relying on more than one method will tend to ameliorate any anomalies that result from "model risk" associated with the use of only one method.

The Commission should not mandate a rigid formulaic average of these methods, regardless of how many methods are ultimately considered. The Commission should retain the flexibility to apply different weights to the specific methods that are found to be appropriate for each of the industries it regulates based on market conditions during the pendency of a rate case. The Commission should be permitted to consider the extent to which any of the methods being used may deviate from real world conditions, and to align such weighting more closely with how financial analysts are currently using these methodologies in light of such market conditions.

Ratemaking often requires the application of judgment based on individual facts and circumstances.[76] The Commission determines a range of reasonable returns due to an inability to estimate a return with absolute precision.[77] As such, INGAA submits the Commission should not tie its hands by adopting a rigid formulaic approach that would apply regardless of the industry being reviewed or current market conditions.

Mandating a mechanical weighting of the methods the Commission ultimately finds to be appropriate for interstate natural gas pipelines would likely result in the same problems the Commission is attempting to address in the *Coakley/MISO* Briefing Orders

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[76] *Ala. Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).
[77] *FPC v. Conway Corp.*, 426 U.S. 271, 278 (1976).

and NOI. The Commission correctly noted that each of the cost of capital methodologies is based upon different fundamental premises, and these premises are affected by changing capital markets.[78] The Commission is proposing to consider methods in addition to the DCF method because the assumptions underlying the DCF method diverged from real-world conditions in the relevant time period in the *Coakley/MISO* proceedings.[79]

While the *Coakley/MISO* Briefing Orders addressed the DCF method, the Commission correctly acknowledged that "model risk" is inherent to all models. The theoretical underpinning of the other cost of capital methodologies may also be suspect under certain market conditions. Policy-initiated changes in interest rates that are not produced solely by market factors could also artificially skew the results of some of the other methodologies. In Opinion No. 531-B, the Commission noted that it had rejected Risk Premium analyses in the past "due to concerns about the reliability of the methodology to produce reliable results in fluctuating market conditions."[80]

Whether and how market conditions are affecting the assumptions underlying any of the methods is a fact intensive question that cannot be accommodated by a mechanically mandated approach. For example, evidence and expert analysis of changes in Treasury bond rates, utility bond rates and corporate bond rates, as well the spreads between these rates, may be needed to determine the impact of these changes on the assumptions of the

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[78] *Coakley* Briefing Order at P 34; MISO Briefing Order at P 36.

[79] The Commission found that during the periods at issue in the *Coakley/MISO* proceedings, "average utility stock prices increased by more than would be justified by any increase in utility earnings or projected growth in earnings." The Commission further noted that utilities' price to earnings ("PE") ratios had increased substantially and had shown extreme volatility during the relevant period, which was also inconsistent with DCF theory. *Coakley* Briefing Order at P 45; *MISO* Briefing Order at P 47.

[80] *Martha Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 92 (2015), *citing Consumers Energy Co.*, 64 FERC ¶ 63,029, *aff'd* 85 FERC ¶ 61,100 at 61,361 (1998); *New England Power Co.*, 31 FERC ¶ 61,378 at 61,841 (1985).

various methods. A simple arithmetic average of the methods considered may not provide the most reliable ROE estimate.

Allowing flexibility in weighting also is consistent with how analysts utilize these methods to make investment decisions. As the Commission stated in the *Coakley/MISO* Briefing Orders:

> While some investors may give some weight to a DCF analysis, it is clear that other investors place greater weight on one or more of the other methods for estimating the expected returns from a utility investment, as well as taking other factors into account.[81]

Investors do not mechanically average the results of these methods when making investment decisions. They consider numerous factors and place more weight on methodologies they conclude may be better predictors of expected returns given the state of capital markets at the time of their analysis. Investors also may modify and/or customize the methodologies as appropriate to take into account their own analyses of the investment and to avoid anomalous ROEs.

In the *Coakley/MISO* Briefing Orders, the Commission relies on Dr. Morin as support for an equal weighting to different models. The Commission quotes the following statement from Dr. Morin's book *New Regulatory Finance*: "[i]n the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities."[82] Yet, Dr. Morin, as well as other financial scholars he cites in his book, agrees that disproportionate weighting may be appropriate depending on capital

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[81] *Coakley* Briefing Order at P 35; *MISO* Briefing Order at P 37.

[82] *Coakley* Briefing Order at P 36; *MISO* Briefing Order at P 38, *citing* Roger A. Morin, *New Regulatory Finance* 429 (Public Utilities Reports, Inc. 2006).

market conditions. In addition to noting in the quote above that "hard evidence" might indicate an equal weighting may not be appropriate, Dr. Morin also relies on the writings of Professors Eugene Brigham and Stewart Myers. Professor Brigham states that he uses DCF, CAPM and Risk Premium and chooses among them on the basis of his confidence in the data used in each case.[83] If it is appropriate to include or exclude one or more models entirely based on the data in each case, it must also be appropriate to place different weights on these models. Professor Myers stated that "you should not use any one model *or measure mechanically* and exclusively."[84]

Finally, Dr. Morin himself has testified that the weights to be given to the various models may vary with capital markets:

> As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. *The weight accorded to any one method may very well vary depending on unusual circumstances in capital market conditions*.[85]

A flexible approach to weighting the various methods to estimate regulatory ROEs allows the Commission to pursue sound regulatory policy addressing the imprecise nature of estimating expected returns and the "model risk" phenomenon. A flexible approach also is more consistent with the manner in which investors make investment decisions.

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[83] Roger A. Morin, *New Regulatory Finance* 430, *quoting from* Brigham and Ehrhardt (2005).
[84] *Id*. *quoting from* Myers (1972).
[85] Prepared Direct Testimony of Roger A. Morin, Ph.D. on behalf of San Diego Gas & Electric Company before the Public Utilities Commission of the State of California, dated April 20, 2012, in Docket No. 266448, Application: A 12-04 at 17 (emphasis added).

1. DCF

a. Incorporation of Distributable Cash Flow or Stock Buybacks.

In the NOI, the Commission asks whether it should continue to use a dividend DCF model or switch to a DCF model, for example, that is based on free cash flow. NOI at P 38 (Q:H.2.a.1). INGAA submits that free cash flow, or more specifically the related metric of distributable cash flow ("Distributable CF"), should be reflected in the DCF model.[86] As discussed below, INGAA does not believe the Commission needs to use a different DCF model based upon free cash flow as implied in the Commission's question. Rather, INGAA proposes a slight adjustment in the calculation of the dividend yield to recognize the additional cash that will be available to companies in the future.

Dr. Vilbert explains in his affidavit why the failure of the DCF model to account for changes in dividend/distribution payout ratios understates ROEs calculated by the DCF formula, and why Distributable CF needs to be considered when evaluating this effect. Vilbert Aff. at P 100. While analysts consider Distributable CF in their growth forecasts, the dividend yield component of the formula is understated. The DCF model assumes dividend/distribution payout ratios are constant forever. But under the Commission's two-step model, EPS growth at some point in the future converges with GDP growth. As growth theoretically slows toward GDP, the investment necessary to support such slower growth also declines. As a result, more cash is available to the company for other uses, including higher dividends than assumed in the model. *Id.* at P 101. As the measure of cash flow available after all non-discretionary uses of capital, Distributable CF is the best proxy for the total cash that would be available for dividends if no additional investment is

[86] Dr. Vilbert explains that the related concepts of free cash flow and Distributable CF reflect (1) differences in book and economic depreciation and (2) differences in cash and book taxes. Vilbert Aff. at PP 97-102.

necessary to support growth, or if there is a small amount of growth funded by equity issuances.

Dr. Vilbert notes that investment analysts are well-aware of Distributable CF and likely consider this metric in their earnings per share ("EPS") growth forecasts, particularly for midstream companies. *Id*. Some analysts believe that Distributable CF is the appropriate valuation tool for pipeline companies. Capturing the impact of the DCF model's failure to consider the change in payout ratio and adjusting the model to account for that impact in a precise way, however, is difficult and depends on multiple assumptions. Therefore, INGAA proposes a pragmatic adjustment to recognize the additional cash available to companies not reflected in the dividend yield component of the formula. Similar to the calculation of expected growth in the DCF model, which is based on a ratio of expected short-term and long-term growth, INGAA proposes to calculate the dividend yield as a function of weighted proportions of both a dividend and Distributable CF yield. Consistent with INGAA's proposal to weight short-term growth 80 percent and long-term growth 20 percent, INGAA would propose the same weighting for the dividend yield. That is, the dividend yield would be weighted 80 percent and the Distributable CF yield would be weighted 20 percent. Distributable CFs are reported in Bloomberg and are available in public U.S. Securities and Exchange Commission filings. INGAA proposes to use the last four quarters of Distributable CF because seasonality affects the quarterly values. In the alternative, INGAA requests that the Commission recognize that the DCF model's failure to account for changing payout ratios, and the cash which would subsequently be available for dividends (as represented by Distributable CF), understates the ROEs produced by the model. The Commission should allow parties to propose solutions in individual rate cases.

If the Commission declines to require an adjustment to account for the impact of Distributable CF in the DCF model in this proceeding, at a minimum, share repurchases or buybacks must be included in the dividend yield component of the formula. Dr. Vilbert explains that from an investor's perspective, there is similar value generated from a dividend payment and a payment to purchase the investor's shares. The DCF model's failure to consider this alternative source of cash to investors understates the dividend yield. Vilbert Aff. at P 104. Dr. Vilbert notes that this failure has been noticed by economists and adjustments to the model have been proposed. *Id*. Dr. Vilbert proposes a simple adjustment to remedy the problem: add the dollar value of the shares repurchased to the dividend yield. The precise formula would be to add to the dividend yield another yield calculated as the dollar value of shares repurchased divided by the price of the shares times the number of outstanding shares before the repurchase. If the price at which shares are repurchased is assumed to be equal to the average in the two-step model, the adjustment is simply to add the percentage of total shares forecast to be repurchased to the dividend yield. In other words, if one percent of the total shares were forecast to be repurchased, the dividend yield should be increased by one percent. *Id.* at P 105. The simple formula is as follows:

$$\text{Adjustment to the dividend yield} = (SH_{Rp} * P_S)/(SH_{OUT} * P_S)$$

Where SH_{Rp} = Shares repurchased,

SH_{Out} = Total shares outstanding before repurchase, and

P_S = Price of shares repurchased.

b. FERC Should Employ a Quarterly DCF Model to Calculate DCF Dividend Yields.

INGAA proposes to utilize a quarterly version of the DCF model as opposed to the currently utilized annual version. As discussed in Dr. Vilbert's affidavit, the quarterly DCF model is identical to the annual version of the model except that the model uses quarterly inputs instead of annual inputs in order to coincide with the quarterly dividend payments made by companies in the proxy group. Vilbert Aff. at P 84. Dr. Vilbert proposes that the actual pattern of dividend payments can be captured properly by using the actual quarterly dividend multiplied by (1 + the compound quarterly forecast EPS growth rate) and then adding the quarterly growth rate to obtain the quarterly estimate of the ROE. The quarterly ROE estimate is then annualized to derive the annual ROE. The calculation to annualize the quarterly ROE estimate is as follows: annualized ROE is equal to (1 + quarterly ROE)^4 -1. In other words, raise (1 + the quarterly estimate) to the fourth power and subtract 1 as shown in the equation below:

$$ROE_{annual} = \left(1 + ROE_{Quarter}\right)^4 - 1$$

The quarterly DCF model produces more accurate ROE estimates because the inputs match actual dividend payments and quarterly compound growth rates. The quarterly DCF model removes the need to modify the dividend yield by ½, which is done under FERC's traditional two-step DCF model to approximate the timing of dividend increases during any given year. By utilizing the quarterly DCF model, there is no need to approximate dividend increases within a year, since the model period perfectly matches the timing of dividend payments. For these reasons, the Commission should adopt the quarterly DCF model.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

c. <u>FERC Should Supplement IBES Growth Forecasts with Value Line to Develop a Weighted Average Growth Rate.</u>

The Commission currently relies upon three to five-year growth rate estimates published by Institutional Brokers Estimate System ("IBES") for short-term growth forecasts in the DCF methodology.[87] The NOI asks questions about the infirmities of IBES and whether other sources should be considered for establishing a short-term growth rate.[88] INGAA acknowledges that there are some weaknesses at times with either the number of analysts reporting to IBES and the frequency of IBES's updates, yet *IBES* remains a valuable tool for obtaining short-term growth rate estimates and should not be discarded. INGAA proposes that FERC should supplement IBES growth forecasts with the Value Line forecast for each proxy group member and average the forecasts of all analysts included in both services. If IBES includes four analyst forecasts in its consensus, those four forecasts plus the Value Line forecast would be averaged to establish the short-term growth rate, with each of the five forecasts being given equal weight. This proposal would mitigate some of the problems that stem from an exclusive reliance on IBES forecasts and will ensure that short-term growth estimates in the DCF formula are more reliable and more representative of analysts' consensus.

The use of Value Line forecasts as a supplement to IBES is consistent with the Commission's preference for consensus growth estimates. Vilbert Aff. at P 76. Value Line analysts are independent from those that provide estimates to IBES because Value Line analysts do not provide their data to any service except for Value Line. As a result, supplementing the IBES "consensus", which is merely the average of estimates from

[87] *See e.g.*, NOI at P 8.
[88] *Id*. at P 38.

individual analysts, strengthens the consensus estimate by increasing the amount of information considered in its development by increasing the number of analysts providing estimates.

Supplementing IBES forecasts with Value Line's forecasts also will address the concerns voiced by the Commission in the *Coakley/MISO* Briefing Orders regarding the diminishing number of IBES projections for proxy group entities.[89] As Dr. Vilbert notes, IBES estimates result from averaging estimates from what is often a small and variable group of contributing analysts. Vilbert Aff. at P 78. Any changes in the group of analysts reporting to IBES could have an enormous impact on the IBES consensus estimate. Supplementing IBES data with Value Line to develop a weighted average growth rate would reduce the impact of changes in the composition of IBES reporting analysts.

The use of Value Line estimates also could provide more current forecasts than IBES in certain situations. As Dr. Vilbert notes, Value Line estimates must be updated every 13 weeks at a minimum, while IBES estimates are updated on a rolling basis. Vilbert Aff. at P 82. While it is possible that IBES estimates are updated more frequently than Value Line estimates for some proxy group companies, there also have been times where IBES forecasts remained unchanged for up to 180 days. Given that neither of the services are always more current than the other, the Commission should consider both services.

d. <u>The Weight Afforded Long-Term Growth in the DCF Formula Should Be Reduced from One-Third to One-Fifth.</u>

The Commission requests comments on whether analysts project growth in earnings or dividends beyond five years, GDP is an appropriate proxy for long-term growth, and FERC should change the weighting of short-term and long-term growth. NOI

[89] *Coakley* Briefing Order at P 48.

at P 38 (Q H.2.a.3, H.2.a.4). While the Commission currently gives two-thirds weighting to short-term growth and one-third weighting to long-term growth, INGAA proposes changing the weighting to four-fifths for short-term growth and one-fifth for long-term growth. INGAA's proposal reflects the reality that analysts rely heavily on short-term growth projections and rarely, if ever, consider long-term projections. INGAA's revised weighting thus would mitigate some of the problems inherent in utilizing long-term growth projections.

In FERC Order No. 414-A, the Commission adopted its current practice of giving two-thirds weight to short-term growth and one-third weight to long-term growth.[90] In altering its previous policy to give equal weighting to short-term and long-term growth rates, the Commission reasoned that short-term growth rates should be given greater weight, because "[t]here is no serious disagreement that a projection of short-term growth is important in establishing the appropriate ROE for a pipeline. No such relative consensus exists with respect to the use or reliability of long-term growth projections."[91] The Commission also emphasized that other elements of a pipeline's cost-of-service, developed utilizing a specific test period, represent a short-term projection and that long-term projections are inherently less reliable than short-term projections.[92] If the Commission wishes to continue relying upon a long-term growth rate in the DCF methodology as a way to normalize potential anomalies, INGAA proposes a reasonable incremental adjustment of reducing the weighting of the long-term growth rate to one-fifth.

[90] *Transcontinental Gas Pipe Line Corp.*, Order on Rehearing, 84 FERC ¶ 61,084 at p. 61,423 (1998) ("Order 414-A").
[91] *Id*.
[92] *Id*.

This modest adjustment is supported by a number of factors. First, one of the Commission's objectives in the NOI is to more closely align the models for projecting expected returns with how analysts make investment decisions. Because of the inherent unreliability of long-term growth projections, analysts rarely, if ever, rely on such projections, and specifically do not rely on GDP. This fact is demonstrated by the absence of analyst growth projections longer than five years. Second, forecast GDP growth rates from 2018-2050 are 133 basis points below the historical real compound GDP growth rate from 1929-2018. Vilbert Aff. at P 87. It is unknown how long this phenomenon will last and whether it results from undue pessimism relative to historical growth. Therefore, the use of GDP in the DCF formula is currently understating ROEs and may continue to do so for some time.

e. <u>The Commission Should Confirm That the Growth Factor Component of the Dividend Yield Should Be Based Solely on Short-Term Growth Rates.</u>

The DCF formula includes an adjustment to the six-month average of the dividend yield by a growth factor of (1 + 0.5g). There is some confusion in Commission cases concerning how to calculate the "g" in this formula. In an appendix attached to the *Coakley* Briefing Order, the Commission includes a general description of the four models it is proposing to consider in determining ROEs.[93] In its discussion of the DCF model, the Commission states that "under the Commission's two-step DCF methodology, the input for the expected dividend growth rate, "g," is calculated using both short-term and long-term growth projections." INGAA submits this statement confuses the "g" factor used to derive the dividend yield with derivation of an overall growth rates. The latter is a based

[93] *Coakley* Briefing Order, Appendix at p. 40.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

on a weighting of short-term and long-term growth rates, but the former should be based on only short-term IBES growth rates.

The Commission addressed this precise issue in *Seaway Crude Pipeline Co*., 154 FERC ¶ 61,070 at P 198 (2016). In that case, the Commission reversed the finding of the Administrative Law Judge that the "g" factor should be based on a weighting of short-term and long-term growth and held that only short-term IBES forecasts should be used for this purpose. Dr. Vilbert explains that the Commission got it right in *Seaway* because the IBES 3-5 year forecasts are likely to be more representative of the growth in dividends over the short term. Vilbert Aff. at P 83. The Commission should confirm that its holding in *Seaway* represents its policy and applies across all industries it regulates.

f. <u>The 50 Percent Reduction in the Long-Term Growth Rate for MLPs Should Be Eliminated.</u>

In a 2008 Policy Statement addressing the composition of proxy groups for natural gas and oil pipelines, the Commission announced a policy of reducing the long-term growth rate in the two-stage DCF formula by 50 percent for MLPs.[94] The Commission found at the time that MLPs, unlike corporations, cannot be expected to grow over the long-term at the same rate as the economy as a whole. After discussing various proposals made in the docket, the Commission then concluded "[i]n light of the inherent difficulty of projecting long-term growth, the 50 percent of GDP proposal would appear to result in a long-term growth projection that falls within any reasonable margin of error for such projections, while giving recognition to the fact that investors expect MLPs' long-term growth to be less than that of GDP."[95]

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[94] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Policy Statement, 123 FERC ¶ 61,048 (2008) ("2008 Policy Statement").
[95] *Id.* at P 96.

INGAA submits that this adjustment should be eliminated. The notion that a firm's long-term growth rate will vary based on organizational structure, or that MLPs can be expected to grow over the long-term by 50 percent less than corporations, has never been supported with evidence or based on sound financial theory.[96] The result of the Commission's implementation of this policy has been an arbitrary reduction in interstate natural gas pipeline ROEs derived under a DCF model whenever MLPs are included in a pipeline proxy group. The negative impact on pipeline ROEs resulting from this policy has been exacerbated by the Commission's recent Revised Policy Statement eliminating an income tax allowance ("ITA") for MLPs and other pipelines structured as partnerships or pass-through entities.[97] As discussed by Dr. Vilbert and explained below, the increased risk faced by MLPs as a result of the elimination of an ITA from their rates renders this arbitrary 50 percent reduction more untenable and unjustifiable. Vilbert Aff. at P 94.

Dr. Vilbert explains that there is no reason to believe MLPs will grow more slowly than identical C-corporations. Vilbert Aff. at P 93. The belief expressed by the Commission in the 2008 Policy Statement that MLPs may not be able to maintain growth because they have fewer opportunities to participate in the broad economy has not been borne out by experience.[98] Until the recent elimination of ITAs for MLPs, which has caused many but not all MLPs to reorganize, MLPs have thrived. There is no evidence

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[96] The long-term growth estimates of investment houses relied upon by the Commission to support this 50% reduction in the 2008 Policy Statement were simply conservative estimates used by analysts due to the difficulty of projecting long-term growth. These analysts provided such conservative long-term growth estimates for both corporations and MLPs and such projections did not support a 50% reduction for MLPs. *See* Transcript of Technical Conference re Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity at 35, Comments of Yves Siegel, Managing Director, Wachovia Capital Markets, Docket No. PL07-2-000 (Jan. 23, 2008).

[97] *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs,* Revised Policy Statement on Treatment of Income Taxes, 162 FERC ¶ 61,227, *order on reh'g,* 164 FERC ¶ 61,030 (2018) ("Revised Policy Statement").

[98] 2008 Policy Statement at PP 92-93.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

that MLPs failed to sustain growth, had grown less than corporations, or had grown at 50 percent of GDP, over the ten years since this policy was adopted in 2008.

Regardless of whether a 50 percent reduction in MLPs' long-term growth was supportable in 2008, it is not supportable at this time. Due to the disallowance of income tax costs in their rates, MLPs have become more risky investments. Vilbert Aff. at P 94. Without an ITA, MLP's net income is more variable and the increase in variability is likely to be systematic. *Id*. Investors will require a greater return to invest in MLPs solely by virtue of their organizational structure. MLP returns should be at least as high as corporations, not less due to different treatment in the DCF model.

A major premise of the 50 percent growth rate reduction for MLPs may no longer be valid as a result of the elimination of the ITA from MLP rates. In the 2008 Policy Statement, the Commission reasoned that MLP growth rates would be lower than corporate growth rates because MLPs pay more in distributions to their investors in comparison to corporations, and thus retain less of their earnings to invest in growth.[99] One impact of eliminating the ITA is that MLPs' access to equity capital markets has diminished as MLP investments have become less attractive. MLPs are forced to generate growth internally through retained earnings. The difference in growth strategies that caused the Commission to adopt the MLP 50% reduction at best has been greatly diminished, and at worst no longer exists.

The combination of an elimination of the ITA and a 50 percent reduction in the long-term growth rate for MLPs in the DCF model, creates a double whammy for MLPs. If the pipeline whose ROE is being determined is an MLP, the pipeline will not be provided

[99] *Id*.

an ITA and at the same time will have its ROE reduced to the extent other MLPs are included in its proxy group. Even if the subject pipeline is a corporation, it is very likely that MLPs will be required to be included in the proxy group, in which case pipelines with corporate structures will also suffer arbitrarily lower ROEs. This adjustment should be eliminated.

2. CAPM

The CAPM methodology is based on the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Specifically, the CAPM methodology determines the cost of equity by taking the "risk-free rate" and adding to it the "market-risk premium" multiplied by "beta."

$$\boldsymbol{r_s = r_f + \beta_s \times MRP}$$

where $\boldsymbol{r_S}$ is the cost of capital for investment S;
$\boldsymbol{r_f}$ is the risk-free interest rate;
$\boldsymbol{\beta_S}$ is the beta risk measure for investment S; and
$\boldsymbol{MRP}$ is the market equity risk premium.

Betas approximate a specific stock's risk relative to the broader market. The market risk premium is the risk premium associated with an equity investment of average risk (i.e., the risk of the equity market as a whole) relative to the risk-free rate and indicates the level of risk compensation demanded by capital market participants. Vilbert Aff. at P 35.

As Dr. Vilbert states, CAPM is a long-standing and widely used model to estimate the cost of equity. Vilbert Aff. at P 28. Like the other models raised in the NOI, the CAPM model has its limitations. *See Id*. at P 44. The questions that commonly arise in implementing the model are: (1) what term to maturity of Treasury bonds should be used as the risk-free rate?; (2) whether a current or forecast risk-free rate should be used?; and (3) how should the market risk premium be derived?. *Id*. INGAA comments on these issues as follows:

a. Risk-Free Rate

It is generally not disputed that long-term U.S. Treasury bond interest rates should be used as the risk-free rate in the CAPM. While a 20-year or 30-year Treasury bond rate could be used for the risk-free rate in the CAPM assuming the same rate is used as an input to the market risk premium, Dr. Vilbert proposes utilizing the 20-year rate because 20-year Treasury bond yields are available back to 1926. Conversely, 30-year bonds were not issued for a period of time. Using 20-year bond yields will allow the use of a full historical data set covering a longer period. Vilbert Aff. at P 31. Dr. Vilbert also recommends using forecasted over current risk-free interest rates because they are more consistent with the goal of estimating a forward-looking cost of capital for the period in which rates will be in effect. *Id.* at P 32.

b. Market Risk Premium

The market risk premium is the most important, and typically the most controversial, parameter in CAPM. Dr. Vilbert reviews the various ways to estimate the market risk premium and recommends that the Commission continue to follow the basic methodology approved in Opinion No. 551 for deriving a market risk premium.[100] In that case Dr. Avera submitted a forward-looking analysis based on a DCF single-stage constant growth rate study of all dividend-paying companies in the S&P 500. Dr. Vilbert also supports the use of a weighted average of both IBES and Value Line forecasts to measure

[100] In Opinion No. 551, the Commission approved a size premium adjustment but rejected an industry risk premium adjustment to the CAPM analysis. Opinion No.,551, at PP 166-168. INGAA takes no position on these adjustments at this time.

growth. Vilbert Aff. at P 75. For the reasons discussed in the DCF section of these comments, INGAA additionally proposes that stock buybacks be considered in the DCF-based market risk premium calculation as described in that section.

Dr. Vilbert notes that limiting the S&P 500 sample to dividend paying companies likely creates a downward bias on the market risk premium and ultimately the ROE produced by CAPM. That is because this limitation eliminates companies that choose to invest in internal growth rather than pay dividends. Such companies can be the fastest growing and most risky companies in the index. Vilbert Aff. at P 45. The Commission should take this downward bias into account in evaluating any proposals to implement CAPM in a manner that would further drive the results of CAPM to unreasonably low levels, including, for example, including a two-step growth forecast that incorporates GDP as a measure of long-term growth.

c. Betas

Dr. Vilbert also recommends that the Commission continue to rely on beta estimates from Value Line, with one caveat. The beta estimates provided by Value Line are based on five years of historical data. While five years may be an appropriate historical period upon which to calculate beta estimates in most cases, it is possible that using averages from this long of a look-back period may not appropriately reflect and weigh more recent events that substantially change the risk characteristics of the industry. The Commission should consider beta estimates calculated over shorter periods under such circumstances. Vilbert Aff. at P 54.

3. Expected Earnings

In Opinion No. 551, the Commission approved an Expected Earnings methodology that relies on expected returns on book value of the proxy companies, as forecasted by

Value Line.[101] Because the forecasts were based upon the company's book equity at the end of the year, an adjustment was made to convert the forecast ROE to the average book value of equity over the year. The adjustment used is to multiply the forecast ROE by an adjustment factor equal to [2*(1 + 5-yr. change in equity)]/(2 + 5-yr. change in equity).

INGAA concurs with the Commission's conclusion in Opinion No. 551 that Expected Earnings, as applied in that case, represents a reasonable method to consider in addition to DCF and CAPM.[102] As discussed in Opinion No. 551, a common criticism of Expected Earnings is its potential circularity, but the extent to which the model is circular depends on its implementation. As Dr. Vilbert explains, determining a pipeline's ROE by referencing the historical book returns earned by a proxy group of comparable regulated companies, known as Comparable Earnings, would be circular. Vilbert Aff. at P 116. Comparable Earnings relies heavily on the allowed ROE that has been authorized by the regulator in the past. Reliance on historic allowed ROEs drives the circularity, which is a flaw in the model. Vilbert Aff. at P 116.

The Expected Earnings methodology supported by Dr. Vilbert, and approved by the Commission in Opinion No. 551, largely avoids these criticisms.[103] Because it is based on forecasted returns, it substantially reduces, if not entirely eliminates, the circularity inherent in the use of historical returns. As Dr. Vilbert explains, allowed returns are one factor that analysts consider in forecasting returns, but they are unlikely to be the only factor considered by analysts. Vilbert Aff. at P 117. Analysts also consider economic

[101] Opinion No. 551, 156 FERC ¶ 61,234 at PP 201-239.

[102] Parties should be allowed to propose other methodologies for implementing the Expected Earnings model.

[103] While Dr. Vilbert's proposal to utilize the methodology supported in Opinion No. 551 largely avoids these criticisms, there could be other variations of the Expected Earnings methodology that could also mitigate these concerns.

conditions. If economic conditions change after a regulated return has been established, analysts will attempt to incorporate the effect of the changed economic conditions in their forecasts, and the Expected Earnings model will produce results that could be quite different from current allowed returns. To the extent that the Expected Earnings model is one of three models used to estimate an allowed return, its impact and potential circularity is substantially reduced.

The Expected Earnings model utilizes accounting-based estimates. As Dr. Vilbert explains, that can be viewed as both favorable and unfavorable. Vilbert Aff. at P 114. The negative aspect of an accounting-based measure is that investors are concerned with the expected return on their investment in the market and the Expected Earnings model is not based upon market information. Dr. Vilbert points out that Expected Earnings is the only method among the methods included in the NOI that provides a return on the book value of equity, and is comparable to an allowed return on a book value rate base. The use of forecasted returns on book value is consistent with the application of these estimated returns on the book value of a pipeline's rate base. In the NOI, the Commission recognized the mismatch between the market-based DCF and CAPM methods, and the fact that the return is applied to a book value rate base. NOI at P 36.

In Opinion No. 531-B, the Commission found that investors rely on return on book equity to determine the opportunity cost of investing in a particular company and rely on an Expected Earnings analysis for this purpose.[104] If considered as one of a group of cost of capital models, the Expected Earnings model may capture a different analysis relied upon by investors. As Dr. Vilbert states, by allowing investors to consider and compare

[104] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132 (2015).

expected returns on book equity when deciding to invest, the Expected Earnings model addresses the capital attraction standard of *Hope.* Vilbert Aff. at P 121.

While not free from criticism, the Expected Earnings model should be considered by the Commission in determining gas pipeline returns, provided that (1) it is applied as discussed above; (2) it is included as one model in a group of models that are also used to determine pipeline ROEs; and (3) it may be weighted appropriately based on the facts and circumstances of each case.

4. Outlier Tests

The Commission requests comments on what, if any, are appropriate high-end and low-end outlier tests. NOI at P 34 (Q.D2). INGAA submits that since authorized pipeline ROEs are set at the median of a range of returns of a proxy group, which INGAA proposes the Commission continue to do, there is no need for a high-end outlier test. There is no theoretical basis for eliminating "high" returns produced by the CAPM and DCF models. A low-end outlier test has the theoretical support the high-end outlier test is lacking because investors will not invest in common stock that yield returns lower than bonds. INGAA proposes a modification to the low-end outlier test the Commission has used in the past.

a. <u>High-End Outlier Test</u>

In the *Coakley/MISO* Briefing Orders, the Commission proposed to treat as high-end outliers any proxy company whose cost of equity is more than 150 percent of the median result of all the potential proxy group members in the model producing such returns, subject to a "natural break" analysis.[105] The Commission reasoned that estimated

[105] *Coakley* Briefing Order at P 53; *MISO* Briefing Order at P 54.

returns that exceed this level "suggest that [these returns are] the result of atypical circumstances not representative of the risk profile of a more normal utility." [106]

INGAA disagrees with the premise that any return above an arbitrarily set ceiling suggests atypical circumstances not representative of a "normal" company with commensurate risks. As Dr. Vilbert states, there is simply no theoretical support for a high-end outlier test. If a company is properly included in the proxy group, it should be assumed that it has commensurate risks of not only the pipeline whose ROE is being determined, but of the other companies also included in the proxy group. Unless there is an error in the data, there is no basis to conclude that the calculated return is not "normal". Relying on a measure of dispersion from one return to another to judge the reasonableness of any one return is arbitrary. The fact that a return of one company is "high" in relation to other returns produced by the same model does not suggest the "high" return is the consequence of atypical circumstances. By disqualifying from the proxy group companies that have (1) low or high credit ratings, (2) paid no dividend or announced a cut in dividends, or (3) been involved in a merger, Commission policy already has identified atypical circumstances that could skew a company's expected return.[107]

Dr. Vilbert explains why reliance on so-called natural breaks is not theoretically-sound. Attempting to determine when the magnitude of a "natural break" represents something other than a normal distribution of estimated returns is an undefined and largely subjective task. Vilbert Aff. at P 133. Breaks in estimates would be expected to be larger for a small sample because it provides fewer estimates. The fewer the number of estimates, the more likely the distribution of returns will include breaks of significant magnitude.

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[106] *Id.*

[107] *See* Opinion No. 531, at PP 103-114.

Some estimates may be further from the mean of the distribution than others, but that does not mean that they are not valid estimates. There could be many reasons why a gap between the cost of equity estimated for two companies may (or may not) exist.

There could also be a "break" between estimates in the middle of the rank ordered estimates that is as large as the break between the two highest estimates. As Dr. Vilbert states, it would be illogical to conclude that the break at the top of the list indicates an outlier while having no concern about a similar sized break elsewhere in the distribution of returns. There is no basis to infer that the magnitude of any particular gap between adjacent, rank-ordered cost of equity estimates for the proxy group companies demonstrates where the boundary lies between economically logical and illogical results. Relying on the measure of dispersion from one cost of equity estimate to another to judge the reasonableness of a particular observation is arbitrary.

When an ROE is set at the median of a range of proxy group returns, an outlier-test is unnecessary. As Dr. Vilbert explains, when an ROE is set at the midpoint of the proxy group results, as it is done for the ROE of a group of electric utilities, the chosen return is based on the lowest and highest returns in the range, and the high-end return has a direct and significant impact on the chosen ROE. Vilbert Aff. at P 135. However, if the ROE is set at the median, the level of the highest return in the proxy group has no impact. Whether the highest return is 10 basis points or 200 basis points above the median will not change the median. To the extent the Commission retains the high-end outlier test at all, it should retain it only for proceedings where the allowed ROE is based on the midpoint.

A high-end outlier test also is inconsistent with the DCF and CAPM models. The Commission has found that there is no need for an outlier test for returns produced by a two-step DCF model that measures long-term growth at GDP.[108] Dr. Vilbert agrees that exclusion of a "high" return that incorporates GDP as a measure of long-term growth would be inconsistent with the fact that GDP growth is, by definition, sustainable. Changing the weight on GDP in the model does not alter the underlying rationale that GDP growth is by definition sustainable. A weight of 1/5 still allows for a substantial effect of GDP growth on the weighted-average growth rate in the model.

There is no theoretical justification for a high-outlier test with regard to CAPM because this method, by definition, equates risk with return. The CAPM model utilizes betas to measure the relative risks of the companies in the sample utilized (*e.g.*, the S&P 500). Due to its use of betas, the expected return for all investments, by definition, reflect their risks. A high return accurately reflects higher risks, not atypical circumstances. Dr. Vilbert demonstrates this principle by plotting the "Security Market Line" on a graph. The Security Market Line is a graphical representation of the CAPM formula that plots the relationship between expected returns and the beta, or systematic risk, associated with a security. The slope of the Security Market Line reflects the risk-return tradeoff available in the market. As Dr. Vilbert states, there is little room for CAPM to produce unsustainable estimates because the model itself constrains the estimates to points on the Security Market Line.

The only model of the three proposed by INGAA to be considered in determining gas pipeline ROEs for which a high-end outlier test would have any relevance is the Expected Earnings model. That is because estimates could vary if the company were recovering from an unusual event not otherwise resulting in its disqualification from the

[108] Opinion No. 531, 147 FERC ¶ 61,234 at P 118; *S. Cal Edison Co.* 92 FERC ¶ 61,070 at 61,266 (2000).

proxy group under existing Commission policy. But, as discussed above, the use of a median would obviate the need for a high-end outlier test for the Expected Earnings method as well.

b. Low-End Outlier Test

Unlike the high-end outlier test, there is theoretical support for the Commission's low-end outlier criterion. Under the methodology proposed by the Commission in the *Coakely/MISO* Briefing Orders, estimates that are less than approximately 100 basis points greater than the six-month average BBB-rated utility bond yield are removed.[109] The Commission subjects the 100 basis points demarcation to a "natural break" analysis where the 100 basis points may increase slightly by considering the extent to which the excluded estimates differ from other low-end estimates of the proxy group companies.

The low-end test has support in basic financial theory: any company's bonds are less risky than its equity, and investors cannot be expected to purchase common stock if less risky bonds yield essentially the same return. INGAA agrees that a low-end outlier test is appropriate to eliminate estimates which are inconsistent with financial theory. The theoretical basis for eliminating low-end outliers has been recognized by the Commission.[110]

In the NOI, the Commission requests comments on this low-end outlier test. The Commission first asks whether the test should continue to be based on a fixed value relative to the cost of debt. INGAA submits that the 100 basis point threshold over the BBB-rated utility bond yield should be not be followed. The Commission adopted its 100 basis point

[109] *See Coakley Briefing Order* at P 51.
[110] S. Cal Edison Co., 92 FERC ¶ 61,070 at 61,266 (2000).

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

risk premium threshold for low-end outliers in several ROE decisions that involved market data from 2007 and 2008.[111] Bond yields in recent years have been substantially lower than during the periods at issue in those electric cases, indicating that the equity risk premium now is substantially larger.

If its existing policy for eliminating low-end outliers is not followed, the Commission asks whether either of the two alternatives should be used instead: (a) compare the low-end outlier to the median; or (2) compare the low-end outlier to the cost of debt but vary the spread based on interest rates. NOI at P 34 (Q. D4.a) INGAA proposes the Commission adopt a variant of the second approach of varying the spread on the basis of interest rates.

INGAA proposes the Commission adopt either an approach recommended by Dr. Vilbert, in his attached affidavit, or a similar approach advocated and accepted in Opinion Nos. 531-B and 551, both of which are premised on the relationship of interest rates and risk premiums.[112] Dr. Vilbert proposes a minimum threshold for low-end outliers equal to a150-basis point spread over a BBB-rated yield, and that the spread be adjusted based on a market risk premium ("market risk premium" or "MRP") analysis As discussed by Dr. Vilbert, it is generally acknowledged that there is an inverse relationship between the

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[111] *See Atlantic Path 15, LLC.*, 122 FERC ¶ 61,135 (2008); *Startrans IO, LLC.*, 122 FERC ¶ 61,306 (2008); *Pioneer Transmission, LLC.*, 126 FERC ¶ 61,281 (2009); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 55 (2010).

[112] The Commission has acknowledged this relationship. *See* Opinion No. 531 at P 147 ("[t]he link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment."); Opinion No. 551 at P 197 (rejecting criticisms of the inverse relationship between bond yields and equity risk premiums, and finding that "for every percentage drop of the BBB-rated bond yields, the risk premium increased approximately 77.07 basis points").

market risk premium and the level of interest rates. The MRP increases when interest rates decrease and decreases when interest rates rise. Vilbert Aff. at P 143.

Based on this relationship, Dr. Vilbert calculates a minimum threshold spread by applying the difference in risk, as measured by betas, between BBB rated debt and average equity, to a low estimate of an MRP. Specifically, Dr. Vilbert estimates a difference in debt and equity betas of 0.25 and applies this difference to a conservatively low MRP estimate of 6 percent, which produces a 150-basis point spread. Vilbert Aff. at PP 141-142. Dr, Vilbert also proposes that this spread be increased in low interest rate environments by applying the 0.25 beta difference by whatever MRP is calculated as part of the CAPM analysis in a given rate proceeding. Thus, for example, if the MRP is calculated to be 8 percent in a rate proceeding, the spread would be 0.25 times 8 percent, or 200 basis points.

Alternatively, the Commission should consider adjusting the low-end threshold based on the analysis accepted in Opinion Nos. 531-B and 551.[113] In Opinion Nos. 531-B and 551, the Commission expressly accepted and relied upon evidence that used regression analyses to demonstrate that the premium required by equity investors increased 77 to 91 basis points for each percentage point decline in utility bond yields.[114] The same kind of analysis supports, and can be used to quantify, an adjustment to the traditional, low-end

[113] The Commission has acknowledged this relationship. *See* Opinion No. 531 at P 147 ("[t]he link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment."); Opinion No. 551 at P 197 (rejecting criticisms of the inverse relationship between bond yields and equity risk premiums, and finding that "for every percentage drop of the BBB-rated bond yields, the risk premium increased approximately 77.07 basis points").

[114] Opinion No. 531-B at P 99; Opinion No. 551 at P 197.

proxy screen of 100 basis points above prevailing bond yields. An affidavit recently submitted in Docket No. EL14-12-003 by the MISO Transmission Owners' witness Mr. Adrien M. McKenzie[115] presents the Commission with an example of this approach. Using the same type of regression analysis the Commission accepted in Opinion Nos. 531-B and 551, Mr. McKenzie states that, for the study period at issue in that proceeding, adjusting the 100 basis points threshold for low-end outliers would result in a low-end threshold of 254 basis points above the then-prevailing Baa utility bond yield.[116]

That returns on equity must reflect a proper premium over yields on debt cannot reasonably be debated. However, the Commission's historical, 100 basis points threshold for screening low-end outliers does not adequately accomplish that crucial aspect of ROE determinations. Either of the alternative methods INGAA describes here for adjusting the 100-basis points threshold would be a significant improvement to the Commission's ROE methodology.

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[115] Supplemental Initial Brief of MISO Transmission Owners, Docket No. EL14-12-003, at Appendix 2, Affidavit of Adrien M. McKenzie, CFA (Feb. 13, 2019) ("McKenzie Affidavit"). To the extent the Commission deems it necessary to make this evidence part of the record of this proceeding, INGAA respectfully requests that the Commission take official notice of this document.
[116] McKenzie Affidavit at 28-30.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

IV. CONCLUSION

For the afore-mentioned reasons, INGAA respectfully requests that the Commission accept and consider its comments when determining whether to revise its ROE policies for natural gas pipelines.

Respectfully submitted,

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Policy	)	
For Determining Return on Equity	)	Docket No. PL19-4-000

PREPARED AFFIDAVIT OF

DR. MICHAEL J. VILBERT

ON BEHALF OF

THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

June 26, 2019

TABLE OF CONTENTS

TABLE OF CONTENTS

I, Michael J. Vilbert, state under penalty of perjury that the foregoing is true and correct to the best of my knowledge and information.

I. INTRODUCTION AND QUALIFICATIONS

1. My name is Michael J. Vilbert, and I am a Principal Emeritus of *The Brattle Group* (Brattle). I am submitting this affidavit on behalf of The Interstate Natural Gas Association of America (INGAA). I am sponsoring this Affidavit, Attachment A, as well as Attachment B, which contains my résumé.

2. I am a Principal Emeritus of The Brattle Group, an economic, environmental, and management consulting firm with offices in Boston, Washington D.C., London, San Francisco, Madrid, Rome, New York, Toronto, Sydney, and Brussels with specialties including financial economics, regulatory economics, and the gas, water, and electric industries. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy, an MA from the Fletcher School of Law and Diplomacy, Tufts University, an MBA from the University of Utah, and a Ph.D. in financial economics from the Wharton School of Business at the University of Pennsylvania. My business address is 201 Mission Street, Suite 2800, San Francisco, CA 94105, USA.

3. Brattle's specialties include financial economics, regulatory economics, and the gas, water and electric industries. As a Principal Emeritus of The Brattle Group, I work 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 many regulatory bodies including the Federal Energy Regulatory

Commission ("FERC" or the "Commission"), the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the State Corporation Commission of 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 Michigan Public Service 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. Attachment B contains more information on my professional qualifications.

II. <u>PURPOSE OF AFFIDAVIT</u>

4. INGAA has requested that I respond to some of the questions posed in the Federal Energy Regulatory Commission's (FERC or Commission) Notice of Inquiry (NOI) with regard to how to implement the four models to estimate the return on equity (ROE) proposed in the revised FERC methodology specified in the *Coakley* Briefing Order.[1] The purpose of my affidavit is to explain my recommendations on both application and modifications to the proposed methodologies in the *Coakley* Briefing Order as applied to samples in an interstate natural gas pipeline proceeding.

5. My affidavit is organized as follows. *Section III* formally defines the cost of capital and briefly describes the principles relating to the estimation of the cost of capital for a

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[1] Coakley v. Bangor Hydro-Elec. Co., Opinion No. 531, 147 FERC ¶ 61,234 (2014), order on paper hearing, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), order on reh'g, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), vacated & remanded sub nom. Emera Maine, 854 F.3d 9, order on remand, Coakley v. Bangor Hydro-Elec. Co., 165 FERC ¶ 61,030 (2018) ("*Coakley* Briefing Order").

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

business. *Section IV* first presents the Commission's revised cost of capital estimation methodology and then previews the discussion of the models. *Section V* discusses the capital asset pricing model (CAPM) and my recommended method of implementing the model. *Section VI* presents the theory underlying the discounted cash flow (DCF) model, its strengths and weaknesses, and my proposed adjustments to the DCF model. *Section VII* and *Section VIII* address the Expected Earnings model and Risk Premium model, respectively. *Section IX* critiques FERC's proposed outlier tests for high-end and low-end outliers.

III. <u>COST OF CAPITAL THEORY</u>

A. The Cost of Capital and Risk

6. The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk.*[2] 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 my affidavit, as in the definition of the cost of capital itself, refer to the probability-weighted average of 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" (SML) for short. This line is depicted

[2] See *Principles of Corporate Finance*, 12th edition, 2017, by Brealey, Myers, and Allen, McGraw-Hill/Irwin, p.10 for a discussion of the opportunity cost of capital.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

in Figure 1**.** The higher the risk, the higher the cost of capital. Variations of Figure 1 apply for all investments.

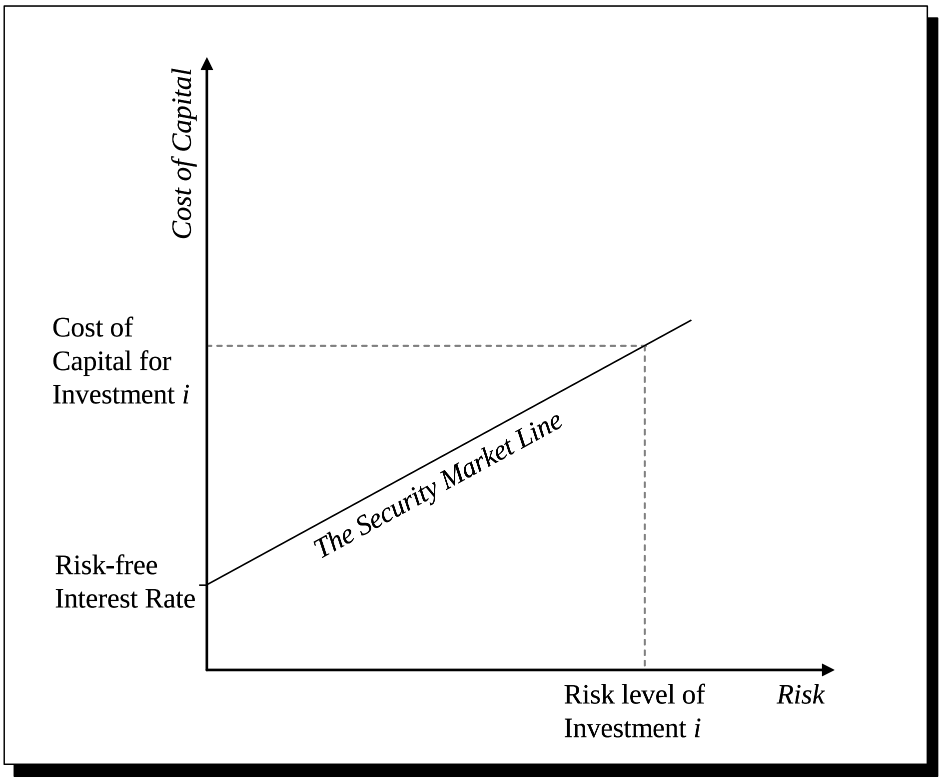

Figure 1: The Security Market Line

B. Application of the Cost of Capital in Regulation

7. In U.S. rate regulation, the "cost of capital" is viewed as the appropriate expected rate of return on utility investment[3] 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)(*Bluefield*), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)(*Hope*).

[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).

8. From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the minimum that compensate investors for the risks they bear.

9. There are short and long-term consequences to setting an expected rate of return below the cost of capital for both investors and consumers. 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 the rate of return is set at higher levels, and customers gain if investors are shortchanged. But in fact, in the short run, such inadequate returns may adversely affect the regulated company's ability to provide stable and favorable rates because some potentially desirable investments may be delayed or may require the utility to file more frequent rate cases. Inadequate returns are likely to cost customers—and society generally—far more than is "gained" in the short run. In the long run, such a return denies a utility 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. As a result, inadequate returns lead to inadequate investment, in existing and 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. Moreover, in capital-intensive industries (such as the natural gas pipeline industry), systems that take a long time to decay cannot be fixed overnight. 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.

10. Finally, the cost of capital cannot be estimated with perfect certainty through any methodology, 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

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

return equals the cost of capital exactly.[4] However, a commission that sets rates so investors expect to earn the cost of capital treats both customers and investors fairly, and acts in the long-run interests of both groups.

IV. THE COMMISSION'S PROPOSED REVISION OF ITS COST OF EQUITY CAPITAL METHODOLOGY

11. This section describes the Commission's proposal to revise its ROE methodology in general and provides the specifics of the implementation of the models.

A. Proposal to Revise FERC Revised ROE Estimation Methodology

12. On October 16th, 2018, FERC issued an Order Directing Briefs (*Coakley* Briefing Order) on the ROE to be used by New England electric utilities for setting transmission rates. FERC proposes to expand the methodological basis for determining the Zone of Reasonableness (ZOR) to a multiple model approach. Brattle has long advocated the use of multiple models when estimating the cost of capital.

13. Various economic theories postulate how the cost of capital is determined in capital markets. Tests of those theories have not yet resolved which model is the best or most reliable method. As a result, there are a number of models in use to estimate the cost of capital.[5]

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4 Setting the revenue requirement requires estimation of numerous parameters such as forecast sales and costs. A systematic estimation error will result in the regulated company not expecting to earn its allowed ROE on average. Systematic in this context means that the regulator either consistently over or under estimates costs or revenues.

5 *Risk and Return For Regulated Industries*, Elsevier, Academic Press, 2017, by Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, p. 5.

14. Because the cost of capital cannot be observed and therefore must be estimated, it is important to use multiple models. No single model should be relied upon in isolation because all models have strengths and weaknesses. Some models perform better under certain economic conditions than others, but each provides information for the analyst to evaluate when forming an opinion on the cost of equity.

B. The Proposed Models

15. The FERC has proposed to expand the models to encompass the following three analyses, each applied to the same proxy group and a fourth model, the Risk Premium model applied to past allowed returns:

1. Capital Asset Pricing Model (CAPM)
2. Two-step DCF Model,
3. Expected Earnings Model, and
4. Risk Premium Model.

16. After excluding low- and high-end outliers from each model's results, the first three proposed methodologies establish a composite Zone of Reasonableness by averaging the high estimates and the low estimates of the three models. Under the Commission's policy, outliers are to be identified as estimates that are less than 100 basis points (bps) greater than the yield on BBB-rated utility debt (low-end) or greater than a 1.5 multiple of the median estimate (high-end), both subject to a "natural break" analysis.

17. A "Presumptively Just and Reasonable" range of ROEs for Average Risk Utilities is established consisting of one quarter of the composite ZOR, centered on the sample midpoint or median ROE estimate.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

18. For setting the new ROE of an average risk utility (*i.e.*, if an existing ROE is determined to be no longer just and reasonable or if setting the ROE for a new service or utility), the methodology uses the average of the midpoints (for a group of companies) or the medians (for a single company) of the three models along with a *single point estimate* from a fourth methodology, the Risk Premium analysis. For setting the ROE of an above average risk utility, the Commission uses the median of the upper half of the composite zone of reasonableness from the DCF, CAPM, and Expected Earnings methods.

V. <u>The Capital Asset Pricing Model</u>

19. In the NOI, the Commission asks the following questions regarding the CAPM.[6]

20. *Question H.2.b.1: If the market risk premium is determined by applying the DCF methodology to a representative market index, should a long-term growth rate be used, as in the Commission's two-step DCF methodology?*

21. My answer is no. I discuss my recommended approach to estimating the market risk premium (MRP) in more detail below.

22. *Question H.2.b.2: Beta is a measure of a security's risk relative to the broader market, such as the S&P 500, not of its absolute risk. Do CAPM's assumptions break down if both utility stocks and the broader market become riskier over time on an absolute basis, but the relative increase in risk in utility stocks rises more slowly?*

23. Theoretically, the answer is no. I interpret riskier on an "absolute basis" to mean that the volatility of the market and the utility industry have both increased. The average beta of

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[6] NOI, P. 38.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

the utility industry will decrease because the beta of the market is always 1.0, and the systematic risk of the utility industry has declined relative to the market. Recall that the theory of the CAPM is that the market is fully diversified so the increased volatility cannot be diversified away. If the stock market is riskier, I would expect that the return on the market to increase as well because the risk-return tradeoff between risk-free assets and the market would have a higher slope. The change in the expected return on utility stocks is undetermined. The expected return on utility stocks will be the net of an increase because of the greater risk-return tradeoff but will decrease because of the reduced industry beta. In either case, theoretically the CAPM should estimate the cost of capital correctly.

24. *Question H.2.b.3: What are appropriate data sources for the beta value?*

25. Beta is calculated somewhat differently by different data sources. I recommend *Value Line* because it is widely available and provides estimates for all sample companies.

26. *Question H.2.b.4: Should the Commission employ more sophisticated versions of the CAPM model that consider more variables instead of only beta, such as the Fama-French Model?*

27. No. Fama and French recognized certain limitations in the CAPM and attempted a revised version to address those limitation, however, in my experience, the estimates from the Fama-French model have been highly variable so that estimates can be quite different simply based on the timing of the estimates even though the sample companies are of comparable risk in both periods.

A. CAPM Theory

28. Modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a premium for risk. The CAPM is the longest-standing and most widely used of these theories. Implementation of the model requires specification of: (1) the current values of the benchmarks that determine the Security Market Line (see Figure 1 above); (2) the relative risk of a security or investment; and (3) how the benchmarks combine to produce the Security Market Line. Given these specifications, a company's cost of capital can be calculated based on its relative risk. Specifically, the CAPM states that the cost of capital for an investment, S (*e.g.*, a particular common stock), is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \qquad \textbf{(1)}$$

where $\boldsymbol{r_S}$ is the cost of capital for investment S;

$\boldsymbol{r_f}$ is the risk-free interest rate;

$\boldsymbol{\beta_S}$ is the beta risk measure for investment S; and

$\boldsymbol{MRP}$ is the market equity risk premium.

29. The CAPM relies on the empirical fact that investors require risky securities to offer a higher expected rate of return than safe securities. It says that the Security Market Line starts at the risk-free interest rate (i.e., the return on a zero-risk security, the y-axis intercept in Figure 1 equals the risk-free interest rate). Further, it says that the risk premium of a security above the risk-free rate equals the product of the beta of that

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

security and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk, i.e., a beta equal to 1.0.

B. Model Parameters

1. The Risk-Free Interest Rate

a. Term to Maturity

30. Modern capital market theories of risk and return use the short-term risk-free rate of return as the starting benchmark, but regulatory bodies such as FERC use a version of the risk positioning model that is based upon the long-term risk-free rate. I recommend relying on the long-term version of the risk positioning model because short-term interest rates are subject to manipulation by the Federal Reserve to manage economic activity. Accordingly, the implementation I recommend requires use of long-term U.S. Treasury bond interest rates.

31. Two aspects of the risk-free interest rate for use in the CAPM are important. First, the risk-free interest rate should be consistent with the MRP. Recall that the MRP represents the additional expected return on an investment of average risk over the yield on the risk-free asset. If the MRP is measured relative to a risk-free Treasury bond with a 20-year term to maturity, the risk-free interest rate in the CAPM should also be for a 20-year Treasury bond. In principle, the CAPM can be estimated with a risk-free interest rate of any term to maturity as long as the MRP used is consistent with the selected risk-free interest rate. In other words, if a 20-year Treasury bond yield is used as the risk-free interest rate in Figure 1, the MRP used should also be relative to a 20-year Treasury bond. Second, there are advantages to using a long-term bond yield over using a short-term

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

Treasury bill yield because long-term bond yields are less volatile. The methodology in the *Coakley* Briefing Order included a 30-year Treasury bond as the benchmark risk-free interest rate perhaps because it is the longest term available; however, there is at least one disadvantage to using the 30-year Treasury bond yield. Specifically, 30-year bonds were not issued for a period of time so that long-term historical data are not available for that time. In contrast, there is data on 20-year Treasury bond yields provided by Duff & Phelps back to 1926. Data provided by Duff & Phelps is useful for many purposes, and it is beneficial to use models that are consistent with the information provided by that service. For this reason, I recommend using 20-year Treasury bond yields as a measure of the risk-free interest rate.

b. Current or Forecast Risk-Free Interest Rate

32. Another aspect of the risk-free interest rate is whether to use current yields or forecast yields. I recommend using a forecast interest rate because the goal is to match the cost of capital as closely as possible with the period rates are expected to be in effect. Decisions in regulatory proceedings always require time to complete, which makes current yields at the time of the analysis out of date by the time the decision is rendered. Use of forecast risk-free interest rates is more consistent with estimating a forward-looking cost of capital than current (*i.e.*, historical) interest rates. Forecast rates may be higher or lower than current yields so there is no concern that forecast rates favor companies or customers.

33. Because investors are aware of and rely upon forecasts to inform their investment decisions, forecast rates are preferable to current rates.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

2. The Market Risk Premium

34. In general, a risk premium is the amount of "excess" return—above the yield on the risk-free benchmark—that investors require to compensate them for taking on risk. As illustrated in Figure 1 above, investors require larger risk premiums for riskier investments. The MRP is the risk premium associated with investing in the market as a whole. The so-called "market portfolio" is a fully diversified portfolio, meaning that the risk of the market consists only of systematic risk which is the risk that affects the cost of capital.

35. The MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimate the cost of equity using the CAPM and other risk-positioning models. Like the cost of capital itself, the MRP is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable and must be inferred or forecasted based on known market information.

36. Experience (*e.g.*, the recent credit crisis in stock markets worldwide and the U.S. market's October Crash of 1987) demonstrates that shareholders, even well-diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free government Treasury securities, investors subject themselves not only to the risk of earning a lower than expected return but also to the risk that they might lose some or all of their initial investment. This is fundamentally why investors demand a risk premium.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

37. The MRP is the most important as well as the most controversial parameter to estimate for the CAPM. There are a number of ways to estimate the MRP, but the four general categories of estimates are those based upon (1) averages from historical data, (2) survey data, (3) the so-call "supply model" which derives the MRP from expected productivity in the real economy, and (4) conditional estimates which attempt to adjust for current economic conditions. Although the MRP can be estimated in different ways, survey evidence is generally regarded as unreliable because it is difficult to ensure that respondents are consistent in their responses. Few analysts rely upon the supply side model perhaps because it is the newest of the methods. Most analysts rely on either historical data or the conditional model using the DCF model to estimate the expected market return. The latter model is often based upon forecast market returns using the dividend valuation model, *i.e.*, the DCF model. The MRP reported in Order No. 551 was calculated using the DCF model using the weighted-average of IBES and *Value Line* EPS growth rate forecasts.[7]

38. All methods of estimating the MRP try to estimate the expected (*i.e.*, forward-looking) MRP even if the estimation method may rely upon historical data. When relying upon historical data, the theory is that the historical data is the best estimate of the expected MRP if you have no other information. In other words, the future will look like the past, but there is always information on current economic conditions.

[7] Order No. 551, P. 138-139.

a. Arithmetic versus Geometric Mean

39. When using historical realized data to estimate the MRP, the appropriate measure of the MRP is the arithmetic mean not the geometric mean. The arithmetic mean represents the expected return on the market which is what the MRP represents. Ibbotson also confirms that the appropriate measure of the MRP is the arithmetic mean. Conversely, the geometric mean is a compound rate of return between two periods and is appropriate for measuring performance.

b. Market Index

40. Estimation of the MRP requires specifying a market index. There are several choices, but the two most often used are the S&P 500 Index and the New York Stock Exchange Index (NYSE). Both are market-value weighted-average indices, and the returns between the two indices are highly correlated, meaning that there is little difference in the daily percentage point changes in the indices. I recommend the S&P 500 index which is the index used to develop the MRP estimate in the *Coakley* Briefing Order.

c. Historical Estimate

41. Duff & Phelps publishes historical realized returns on the S&P 500 back to 1926 in their publication *Ibbotson Stock, Bonds, Bills, and Inflation*. When estimating the MRP using historical data, Ibbotson recommends using the longest period for which reliable data is

available. The benefit of this method is that the MRP can be "looked up" in the annual Duff & Phelps publication. The historical estimate of the MRP is 6.94 percent.[8]

42. The weakness of the historical MRP estimate is that it does not consider current economic conditions which means that it is an unconditional estimate. An unconditional estimate is the best estimate if you have no information on current capital market conditions, but, of course, there is always information available on market conditions. Thus, I recommend the conditional estimate of the MRP.

d. Conditional MRP Estimates

43. The difficulty with estimating a conditional MRP is determining the best way to make the estimate. The most prevalent way to estimate a conditional MRP is through the dividend valuation model, *i.e.*, the DCF model. As discussed earlier, the DCF model requires a dividend yield and a growth rate. The dividend yield can be for the market as a whole (top down estimate) or for individual stocks within the selected market index weighted by the market capitalization of each individual stock (bottom up estimate). Similarly, the growth rate of dividends (and earnings and stock price) can be estimated for the market as a whole or as the market-capitalization weighted-average of the stocks in the index.

[8] Duff and Phelps's *Ibbotson SBBI 2018 Valuation Yearbook* reports the realized arithmetic average MRP from 1926 to 2017 to be 7.07 percent. This decreased to 6.94 percent in the *Ibbotson SBBI 2019 Valuation Yearbook* from the period 1926 to 2018.

44. *Value Line* publishes the expected dividend yield and growth rate for the market, making the top down method relatively easy.[9] However, the top down approach can be criticized as being based upon the opinion of one analyst or one reporting firm as opposed to the more consensus view of multiple analysts focusing on individual companies in the index.

45. The bottom up estimate requires market-capitalization weighted-average dividend yield information for all companies in the index (*e.g.*, S&P 500) and weighted-average earnings per share (EPS) information for all dividend paying stocks in the index. Note one weakness of the bottom up approach: it can only be applied to dividend paying stocks, and non-dividend paying stocks are frequently companies whose growth prospects are so valuable that they chose to reinvest in the company to support additional growth rather than pay dividends. To the extent that the non-dividend paying stocks are among the fastest growing and most risky companies in the index, the bottom up approach has a downward bias.

46. The dividend yield in the MRP estimate should also be adjusted for share repurchases. If share repurchase is ignored, a source of cash to investors will be omitted, and dividend yield will be understated. A comparison of the weighted-average dividend yield and share repurchase yield is shown in Figure 2 using data from Bloomberg. Share buybacks yield actually exceeds dividend yield on the S&P 500 over the last six quarters as shown in Figure 3.

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9 *Value Line* publishes Part 1, Summary & Index weekly. The median of estimated dividend yields on all dividend paying stocks over the next 12 months and the median capital gain for the universe of 1700 stocks covered by the publication are provided.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

Figure 2: Dividend yield and share buyback yield on S&P 500

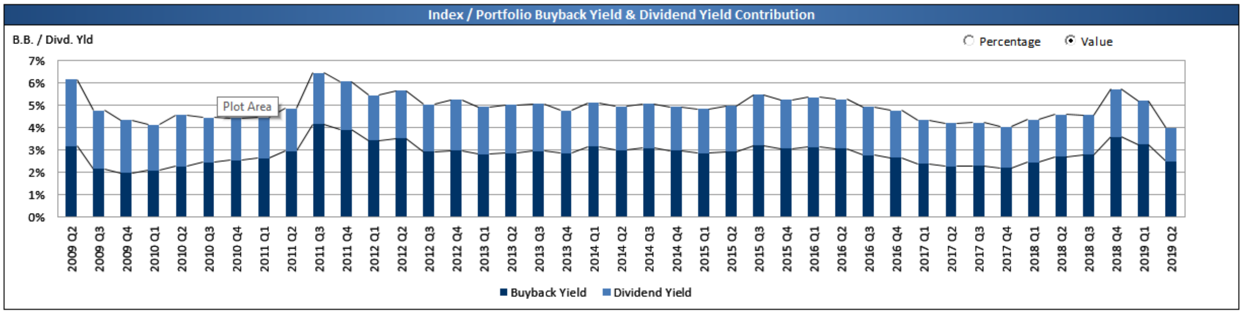

Figure 3: Buyback Yield and Dividend Yield on the S&P 500

Period	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Buyback (BLN)	8.07	197.38	219.26	203.00	196.00	182.80
Buyback Yield	2.51%	3.26%	3.58%	2.78%	2.69%	2.46%
Dividend (BLN)	4.99	123.11	125.85	119.44	119.14	114.76
Dividend Yield	1.49%	1.94%	2.14%	1.79%	1.89%	1.90%

47. Adjusting the dividend yield for share repurchase can be done by adding an additional term to the dividend yield portion of the DCF model using the following method: Adjusted dividend yield is dividend*(1 +forecast EPS growth)/price + (dollar value of shares repurchased)/(price of shares times shares outstanding before repurchase).

48. Note that the (1 + g) term is only multiplied times the dividends paid portion of the dividend yield because share repurchase cannot grow indefinitely. The share repurchases dollars are equal to the announced number of shares to be repurchased times the price per share. The adjustment for share repurchase is discussed in more detail in in the discussion of the DCF model in *Section VI*.

49. The MRP reported in Order No. 551 by Dr. Avera used a bottom up approach and used a single-stage DCF model on all dividend paying stocks in the S&P 500 index. He relied upon EPS growth rate estimates from IBES and *Value Line* without screening the growth rates estimates or the resulting ROE estimates for individual companies. Some object

that individual company estimates may be high while others may be low, but the actual calculation is of a weighted-average dividend yield plus a weighted-average growth rate for the market as a whole. Note that the weighted average growth rate for the S&P 500 includes both high and low growth rate estimates and reflects the expected growth rate of the S&P 500, but it omits the forecast growth rate for the non-dividend paying stocks, which may be among the fastest growing companies in the index.

50. I recommend including share repurchases in the dividend yield and estimating the expected growth rate for the dividend paying companies in the S&P 500 using the weighted-average growth rate from IBES and *Value Line*. The estimated MRP is the estimated return on the market minus the yield on the benchmark interest rate

3. Beta

51. Beta (β) represents the sensitivity of a given security's or portfolio's returns to the market's returns. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Formally,

$$\boldsymbol{\beta_s} = \frac{covariance(\boldsymbol{r_s}, \boldsymbol{R_m})}{variance(\boldsymbol{R_m})} \qquad \textbf{(2)}$$

where $\boldsymbol{R_m}$ is the return on the market portfolio.

52. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. That is, it measures the "systematic" risk of a stock—the extent to which a stock's value fluctuates more or less

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

than average when the market fluctuates. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

53. FERC has long relied upon beta estimates provided by *Value Line*. *Value Line* betas are estimated using 5 years of weekly return data (*i.e.*, 260 weeks) using the NYSE as the market return. *Value Line* betas are "adjusted" which, for an estimated beta greater than 1.0, results in a decrease in the adjusted beta relative to the unadjusted beta estimate. Interstate pipeline sample companies frequently have *Value Line* betas greater than 1.0, which means that their unadjusted betas are even higher.

54. I recommend that FERC continue to rely upon beta estimates from *Value Line*. However, I recommend that FERC also leave open the possibility of using an alternative source of beta estimates for an industry that has experienced a substantial change in the risk. Return data further in the past will not reflect the changed risk characteristic of the industry so that relying upon 5 years of historical data may not reflect the industry's risk as well as a beta estimated using a shorter time period. In the case of altered industry risk, an alternate source of betas will be required including calculating betas by the analyst.

VI. FERC Two-Step DCF Model

55. In Section C of the NOI, the Commission asks about the performance of the DCF Model. In particular, the "Commission seeks comment on the robustness of the DCF model over time and under differing investment conditions."[10]

56. *Question C1: "The DCF model assumes stock prices are equal to the present value of projected future cash flows. Is there evidence of situations when these assumptions are inaccurate?"*

57. *Question C2: "Have current and projected proxy company earnings over the last 10 to 20 years increased in a manner that would justify any increases in their stock prices over the same period, consistent with DCF model assumptions?"*

58. *Question C3: "How does the DCF methodology perform over a wide range of interest rate conditions?"*

59. *Question C3.a: "What specific assumptions of the DCF model, if any, do not work well in low or high interest rate environments?"*

60. *Question C3.b: "Is there evidence that the volatility of price-to-earnings ratios over the last 10 to 20 years, assumed to be constant in the DCF methodology, has been driven by the wide swings in interest rates over this period? If so, would the constant P/E assumption impact the award of reasonable ROEs?"*

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[10] NOI, P. 33.

61. In this section of my affidavit, I address the DCF model and my proposed modifications to its implementation. The discussion addresses most of the Commission's questions.

A. Theory of the DCF Model

62. The DCF model takes the first approach to cost of capital estimation, *i.e.*, to attempt to estimate the cost of capital in one step instead of estimating the cost of capital for the entire market and then determining the cost of capital for an individual investment as is done with the CAPM. 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. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad \textbf{(3)}$$

where P_0 is the current market price of the stock;

D_t is the dividend cash flow expected at the end of period t;

T is the last period in which a dividend cash flow is to be received; and

r is the cost of equity capital.

63. The formula simply says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

64. Most DCF applications go even further and make strong assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the cost

of capital. Specifically, if investors expect a dividend stream that will grow forever at a steady rate, then the market price of the stock will be given by a very simple formula:

$$P_0 = \frac{D_1}{r - g} \tag{4}$$

where D_1 is the dividend expected at the end of the first period, g is the perpetual growth rate, and P_0 and r are the current market price and the cost of equity capital, as before.

65. Equation (4) is a simplified version of Equation (3) that can be solved to yield the well-known "DCF formula" for the cost of capital, Equation (5):

$$r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g \tag{5}$$

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.

66. Equation (5) says that if Equation (4) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future (constant) growth rate of dividends. I refer to this as the "simple DCF" model. Of course, the "simple" model is simple because it relies on strong assumptions. If the assumptions are violated, the model could produce biased estimates.

67. The DCF approach is grounded in solid finance theory. It is widely accepted by regulatory commissions and provides useful insight regarding the cost of capital based on forward-looking metrics. DCF estimates of the cost of capital complement those of the CAPM because the two methods rely on different inputs and assumptions. The DCF method is particularly valuable in the current economic environment, because of the

effects on capital market conditions of the Fed's efforts to maintain interest rates at historically low levels which can bias the CAPM estimates downward if not considered in the implementation of the CAPM.

B. FERC Two-Step DCF Model

68. The proposed two-step DCF model in the *Coakley* Briefing Order is largely unchanged. The ROE estimated is the sum of the dividend yield and an estimated growth rate in earnings per share (EPS). The growth rate is estimated as the weighted-average of the IBES 3-5 year earnings per share (EPS) forecast (2/3rd weight) and the forecast of long-term GDP growth rate (1/3rd weight). The dividend yield is calculated as the 6-month average of the dividend yield adjusted by (1 + 0.5 g) where g is the EPS growth rate. The formula is below.

$$r = \frac{D_0 \, * \, (1 + 0.5g)}{P_0} + g \qquad \textbf{(6)}$$

Strengths and Weaknesses of the DCF Model

69. Current market conditions affect all cost of capital estimation models to some degree, but the DCF model has at least one advantage over the CAPM. Specifically, the DCF model reflects current market conditions more quickly because the market price of a company's stock changes daily.[11] In theory, the dividend yield will adjust quickly to changes in interest rates because among other things investors compare dividend yields with bond yields. In general, when interest rates in the economy increase, stock prices

[11] The advantage is weakened somewhat by the reliance on a 6-month average dividend yield instead of a shorter period. Six months represents two dividend payments.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

decline. Dividend yields increase when market prices fall and reflect the increased cost of capital.

70. The challenge for the DCF model is that the model requires forecasts of earnings growth rates. Although market prices may adjust quickly, revised EPS growth rate forecasts are generally available with a lag so there may be a mismatch between the dividend yield and the forecast EPS growth rates. Moreover, EPS forecasts are more reliable when based upon stable economic conditions which are required to satisfy the constant dividend growth rate assumption. The model assumes a constant payout ratio, a constant growth rate in dividends and EPS, a growth of earnings less than the discount rate, *i.e.*, the constant cost of capital, and a constant price/earnings ratio. If economic conditions are not stable, it is unlikely that a company's EPS growth rates would be stable either.[12] Although the dividend yield quickly reacts to changes in the market, the growth rate estimates may be less precise during times of market uncertainty because future growth rates may be more volatile.

71. In times of economic turmoil, the DCF model's estimates could be affected by a "flight to safety" in which demand increases for relatively safe investments such as bonds and regulated companies. The effect is an increase in the price of regulated companies with a corresponding decrease in dividend yield. The dividend yield should decrease as interest rates decrease but may do so to a greater degree than warranted as a result of the flight to safety. Nevertheless, because dividend yields and forecast growth rates change

[12] It is not fruitful to try to define stable economic conditions, but economic conditions in two periods can be compared.

quickly, the DCF model is likely to more quickly reflect investors' current cost of capital expectations than other models.

72. I recognize that the DCF model, like all models, relies upon assumptions that do not always correspond to reality. For example, the DCF approach assumes that the variant of the present value formula that is used matches the variations in investor expectations for the growth of dividends, and that the growth rate(s) used in that formula match current investor expectations. In fact, Professor Robert Shiller won a Nobel Prize in Economics[13] for his work showing that stock prices were much more variable than dividends which means that the DCF model may not always estimate the cost of capital correctly. Less frequently noted conditions, such as the value of real options incorporated in a company's market price (i.e., increasing it), may create issues that the DCF model does not incorporate. Nevertheless, under current economic conditions, because of its forward-looking nature, the strengths of the DCF method outweigh any weaknesses the method may have.

73. Of course, the assumptions underlying all models are violated to some degree so the question becomes "Are the assumptions as applied to the specific industry being evaluated currently violated to a greater or lesser degree than is normally the case?" And if violated, what is the likely effect on the estimates? This concern leads to some recommended adjustments to how the Commission implements the model.

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[13] Professor Robert Shiller won the Nobel Prize in Economics in 2013. See https://www.nobelprize.org/prizes/economic-sciences/2013/shiller/facts/.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

C. Recommended Adjustments to FERC Two-Step DCF Model

74. I recommend the following adjustments to the Commission's proposed two-step DCF model. I discuss each adjustment below.

1. Return to the Commission's previous decision[14] and eliminate the need for a high-end outlier test based upon the observation that GDP growth is by definition "sustainable." In the past, some ROE estimates were eliminated as being "unsustainable" because the EPS forecast growth rate was deemed unsustainable if greater than an arbitrary cut off of 13.3 percent. When the two-step model was introduced (called two-step because the growth rate in the model included a weighted average of IBES and GDP), GDP was deemed sustainable by definition, eliminating the need for a high end outlier test. The proposed methodology resurrected the high-end outlier test. The Commission should return to no high-end outlier test for the DCF model. I discuss the outlier test in *Section IX* of my affidavit.

2. Supplement the IBES EPS growth rate forecasts with one from *Value Line* using the weighted-average as the 3-5 year EPS forecast to calculate the short-term growth rate.

3. Use the 3-5 year EPS forecast to calculate the adjusted dividend yield instead of the weighted-average growth rate which includes GDP growth. The 3-5 year EPS forecast is likely to be more representative of dividend growth in the near term that the weighted-average EPS growth rate including GDP.

[14] Coakley Briefing Order, P. 52 referencing Order No 531.

4. Use the quarterly version of the DCF model instead of the annual version. Sample companies pay dividends quarterly so use of the quarterly DCF model is consistent with the actual period of dividend payments. Additionally, it eliminates the need for a 0.50 adjustment to the dividend growth rate in the dividend yield term to approximate when dividends may be increased over the year. There would be no need for an approximation.
5. Change the weight on the GDP growth rate estimate to 1/5th.
6. Recognize that the large and persistent difference between free cash flow and distributable cash flow for midstream companies may bias the DCF model estimates as discussed below.
7. Eliminate the 0.5 adjustment to the GDP growth rate for MLPs.
8. If the adjustment for distributable CF recommended by INGAA is not accepted, recognize that share repurchases are equivalent to dividend payments. Theoretically, the DCF model assumes that a company either pays out earnings in the form of dividends or reinvests its earning in the firm, but companies occasionally repurchase shares. The dividend yield should be adjusted when a company forecasts that it will repurchases shares.

1. Include Growth Rate Estimates from *Value Line*

75. The proposed FERC two-step DCF model relies solely on IBES EPS growth rate estimates for the 3-5 year growth rate estimate. For implementation of the Commission's two-step DCF model, I recommend supplementing IBES growth rate estimates with the *Value Line* forecast for each sample company. The growth rate estimate is a weighted-

average short-term growth rate that combines the IBES forecast with the *Value Line*. The weighted average is equal to the number of IBES analysts included in the consensus forecast times the IBES EPS forecast plus the *Value Line* EPS forecast divided by the number of IBES analysts plus 1 (*i.e.*, the single *Value Line* analyst). For example, if there were two IBES analysts with a consensus forecast of 4.5 percent and the *Value Line* forecast were 6 percent, then the weighted-average EPS consensus forecast would be 5% -- *i.e.*, (4.5% * 2 + 6% * 1) / (2 + 1).

76. I believe that the use of *Value Line*'s EPS estimates is consistent with the intent of the Commission's Opinion No. 551, because the decision established a consensus estimate as the Commission's preferred estimate for growth rates. The Commission wants as valid an estimate as possible of the ROE for the sample companies. In Opinion No. 551, the Commission seemed to be concerned that the EPS forecasts from *Value Line* would be inconsistent with the forecasts from IBES either because the *Value Line* estimates are not as current or because the *Value Line* estimates represent the view of a single analyst and thus do not represent a "consensus" estimate as do the IBES estimates. Neither of these concerns should preclude the use of *Value Line*.

77. Thomson Reuters collects EPS growth rate estimates from individual financial analysts who have agreed to be included in the IBES system. The financial analysts are from different brokerage firms, and to my knowledge there is no system by which the individual analysts under contract to provide estimates to IBES agree on a methodology for preparing their estimates. As noted by the Commission, individual analysts may have a different approach to estimating the growth rate, but slightly different approaches by financial analysts are inherent in the IBES estimates. Rather, the IBES "consensus

estimate" is merely the average of the individual estimates submitted, regardless of how those estimates were prepared. There is no process established to improve, alter, or arrive at the consensus estimate. The consensus estimate is simply the mathematical average of the individual estimates. Moreover, many potential sample companies have an IBES "consensus" 3-5 year estimate from at most two analysts. This was a concern noted by the Commission in the *Coakley* Briefing Order regarding the robustness of the DCF.[15] Namely, the Commission noted that the reduced number of current IBES growth projections raised the question of whether IBES growth rates reflect a consensus among investors, and resulted in the real possibility that a significant change in growth rate by even one analyst can have a major effect on the DCF result. "Accordingly, the decreased number of short-term growth projections necessary to perform a DCF analysis of the proxy companies reduces our confidence in the results of that analysis and its suitability as the sole basis for our ROE determinations."[16] Including estimates from the *Value Line* analysts simply increases the number of estimates in the consensus forecasts.

78. Additionally, in many cases the IBES consensus growth rate forecasts are determined by averaging estimates from a small and variable group of contributing analysts. Changes in the composition of analysts who contribute estimates can alter the reported consensus estimate substantially in a relatively short period of time, especially when there are very few contributing analysts. As a result, the IBES consensus estimate can depend upon when the data source was accessed.

15 *Coakley* Briefing Order, P. 47.

16 *Id.*, P. 48.

79. One way to mitigate such variability in growth rate estimates is to include as many independent earnings growth forecasts as there are available from the financial analyst community. Including an independent estimate from a reputable source such as *Value Line* provides one additional professional view about a company's expected earnings growth performance and contributes to producing a more stable growth rate projection for the sample companies.

80. Relying solely on an IBES "consensus estimate" can also potentially produce skewed results because each contributing analyst could have taken a different approach to calculating growth rates. Any variations in the estimates driven by the methodology employed can be mitigated by considering as many reliable estimates as available and observing their weighted mean values. A weighted average growth rate estimate using estimates from each contributing analyst in IBES and the one analyst represented by *Value Line* furthers this goal. This would enhance FERC's goal of relying upon a consensus estimate because adding the *Value Line* forecast would increase the information in the consensus estimate. As a practical matter, there is no reason to ignore a reliable source of information on a parameter of importance to the DCF model (*i.e.*, the forecast of EPS growth) when information from *Value Line* is widely available and used by investors. Use of *Value Line* information does not detract from use of IBES, but rather enhances the information available to the Commission to make the best possible estimate of the cost of capital.

81. *Value Line* analysts are independent from the analysts who provide estimates to IBES because *Value Line* analysts provide their estimates only to the subscribers to the *Value Line Investment Survey*. There is no overlapping or duplication of the EPS estimates that

comprise the IBES consensus estimate. Moreover, because the *Value Line* analysts are all part of the same organization, their EPS estimates have a structure or approach that is consistent among *Value Line* analysts. In this sense, the estimates from *Value Line* have a degree of consensus and consistency that the IBES estimates lack. The *Value Line* estimates are all from analysts in a single company with a set of internal standards that ensures a comparable approach to investment analysis. In contrast, IBES estimates are from multiple companies and rely on multiple analysts for different sample companies. It is possible, even likely, that no single brokerage company that comprises the IBES average provides EPS estimates for all of the sample companies, unlike *Value Line* which is the sole source of the information on the companies they cover. In fact, relying upon EPS estimates solely from *Value Line* is likely to be the most internally consistent (if not the only internally consistent) set of FERC two-step model ROE estimates available.

82. In Opinion No. 551, the Commission expressed a concern that *Value Line* estimates are updated on a lagging, quarterly basis while IBES estimates are updated on a rolling basis, sometimes with daily frequency.[17] The Commission believes this has the potential to make *Value Line* estimates "stale" relative to the IBES estimates. This is not true, however, because both services contain stale data to some degree. *Value Line* estimates are updated at a minimum of every 13 weeks (*i.e.*, 91 days). Although it is true that IBES estimates may be updated more frequently, it is also true that IBES continues to include estimates in the consensus forecast for up to 180 days before removing the estimate from the consensus forecast for staleness. For sample companies with relatively few EPS estimates in the IBES consensus forecast, including estimates from *Value Line* will not

[17] Order No. 551, P. 64.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

only increase the number of analyst estimates upon which the consensus forecast is based, but it will also potentially result in estimates that are more current on average.

2. Adjusted Dividend Yield

83. To adjust the current dividend for the expected growth in dividends, the Commission's two-step model should rely upon the 3-5 year EPS forecast as opposed to the weighted-average of the 3-5 year EPS forecast and the GDP growth rate forecast. This is consistent with the Commission's decision in the Seaway Crude Pipeline Company LLC proceeding.[18] I recommend that Seaway decision on this point be accepted for interstate natural gas pipelines. The 3-5 year EPS is the expected growth rate of dividends for the next five years, so it should be used to adjust the dividend yield. The long-term growth rate would still be the weighted-average of the IBES and *Value Line* growth rate estimate and forecast GDP growth.

3. Quarterly DCF Model

84. I recommend using a quarterly version of the DCF model as opposed to using an annual version. The quarterly DCF model is identical to the annual version of the model except that the model uses quarterly inputs instead of annual inputs. The DCF model does not specify the period between dividends, and the companies in the samples submitted by analysts before FERC pay dividends quarterly rather than on an annual basis. There is no reason not to match the model to the actual payment interval for dividends. The actual pattern of dividends can be properly captured by using the most recent quarterly dividend

[18] Seaway Crude Pipeline Company LLC, Docket No. IS12-226-002, Opinion No. 546, February 1, 2016, P. 198.

multiplied by (1 + the compound quarterly forecast EPS growth rate) and then adding the quarterly growth rate to obtain the quarterly estimate of the ROE which can then easily be annualized to derive the annual ROE estimate. This is the same as the current FERC two-step except that the inputs are quarterly instead of annual. The quarterly growth can be the current growth rate which a weighted average of the 3-5 year EPS and GDP forecast growth rates as is currently the case. The formula to annualize the quarterly estimate is

$$ROE_{annual} = \left(1 + ROE_{Quarter}\right)^4 - 1$$

85. This method ensures that the quarterly dividends and the quarterly compound growth rate matches the actual payment of dividends reflected in stock prices and provides a more theoretically consistent estimate of the ROE than the approximation using the annual growth rate to estimate the expected dividend yield.

86. The quarterly estimates correspond to the frequency and timing of actual dividend payments. In addition, use of the quarterly DCF model avoids having to modify the dividend yield by ½ — as is done in the Commission's two-step DCF model as an *approximation* to when a dividend increase may occur over the course of a year. Use of the quarterly DCF model eliminates the need to make this approximation because the model period is matched to the timing of dividend payments.

4. Weight on the GDP Growth Rate Forecast

87. The two-step model results are reduced because current forecasts of real GDP growth are lower than the historical average real GDP growth rates. Compound real GDP growth

between 1929 and 2018 was 3.22 percent per year compared to 1.89 percent forecast real GDP growth between 2018 and 2050 based upon forecast data from the Bureau of Economic Analysis. Currently, the difference is 133 bps which seems large, as shown in Table 1.

Table 1

Difference between Historical & Forecasted Real GDP

		Start Year	End Year	Growth Rate
Historical GDP (1929 - 2018)	[a]	1,109	18,566	3.22%
Forecasted GDP (2018 - 2050)	[b]	17,582	32,006	1.89%

Sources & Notes:
[a]: Bureau of Economic Analysis, ''Current-Dollar and 'Real' Gross Domestic Product,'' May 30, 2019 release.
[b]: EIA Annual Energy Outlook 2019 Table A20. Macroeconomic indicators.

88. Obviously, the lower the forecast GDP growth rate, the lower will be the average two-step DCF EPS growth rate forecast. I propose a weighting of 1/5th on forecast GDP and 4/5th on the weighted average of IBES and *Value Line* EPS growth rates.

89. There are several reasons to reduce the weight on the GDP forecast. First, given the low forecast of real GDP growth relative to historical growth, an adjustment would be to weight GDP growth less. If forecasts of real GDP growth are downward biased relative to historical growth due to undue pessimism in the current economic and political environment, giving long-term growth less weight is warranted. Additionally, there is no evidence that investors consider the long-term forecast of GDP growth in their investment decisions. The longest forecasts analysts provide are EPS growth rate forecasts for 3-5 years. To my knowledge, there is no publicly available source for

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

estimates of a longer duration. Investors must not demand such information, or it would be provided by brokerage houses, which implies that investors do not rely upon such forecasts.

90. As noted earlier, the DCF model assumes a constant payout ratio that is consistent with a constant growth rate in EPS. The two-step model is based upon the assumption that EPS growth will slow and converge on the rate of growth of GDP, which is why the growth rate in the FERC two-step DCF model is a blend of short-term and long-term growth rate estimates. However, the assumption of a constant payout ratio is only applicable for the constant growth portion of the model. In the model, a constant payout ratio is associated with a constant retention ratio, *i.e.*, investment of retained earnings. The investment of retained earnings is assumed to generate the growth in EPS. As growth slows, the investment required, *i.e.*, the percentage of retained earnings, necessary to support the reduced growth rate decreases. This means that the payout ratio, and consequently, the dividend payout can increase. The DCF model does not capture that additional cash flow available for dividend growth available as growth rate declines. Giving more weight to the short-term growth is a partial adjustment for this issue.

91. Finally, for midstream companies, distributable cash flow (DistCF) greatly exceeds free cash flow, and the difference is likely to persist for an extended period. As a result, the DCF model is likely to be downward biased. Below I describe how DistCF may bias the DCF estimates. INGAA proposes an adjustment to the dividend yield to correct for the bias, but if that proposal is not accepted, the adjustment to the weight on forecast GDP would be another way to recognize the inherent downward bias in the DCF model due to distributable cash flow.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

5. Eliminate the 0.5 Adjustment for GDP growth for MLPs

92. For MLPs, the Commission current policy is to reduce forecast GDP growth in the FERC two-step DCF model by 50 percent. As I understand the Commission's original concern that resulted in the 50 percent reduction of long-term growth represented by GDP growth was based upon a view of the MLPs' business model, which required that MLPs pay out nearly all of their free cash flow as distributions. To grow, MLPs would issue new equity (i.e., limited partnership (LP) shares) so that their EPS growth rate would be reduced compared to a C-corp. Even if both entities grew at the same rate, the EPS growth rate for the C-corp. would exceed that of the MLP because the C-corp. would rely more upon retained earnings to fund growth than would an MLP.

93. The MLP's business model changed due in part to the elimination of an income tax allowance (ITA) for MLPs. Elimination of the ITA means that MLPs will generate less cash and that MLPs have become less attractive as an investment. This reduces MLPs' access to equity capital markets. As a result, MLPs will rely more on retained earnings to fund growth meaning that fewer LP shares will be issued. EPS growth rates will increase more due to fewer LP shares outstanding than when MLPs funded growth by issuing additional shares. In fact, there is no reason to believe that an MLP will grow more slowly than a C-corp., and given the change in business model, an MLP's EPS will also grow in a similar manner to a C-corp.

94. Moreover, MLPs are riskier now without an ITA because their net income is more variable and the increase in variability is likely to be systematic. The latter point is not a problem if the entire sample consists of MLPs but that is less likely to be the case going forward.

95. Why is net income more variable for an MLP without an ITA? Because the tax obligation absorbs some of the variability in taxable income. With a 25 percent tax rate, an increase of 10 percent in taxable income results in a 7.5 percent increase in net income for a C-corporation, but a 10 percent increase in net income for an MLP. Similarly, for a 10 percent decrease in taxable income, an MLP's net income will decrease by the full 10 percent, but a C-corporation's net income will only decrease by 7.5 percent.

96. These factors justify the elimination of the 0.5 weight on GDP forecast growth in the two-step model for MLPs.

6. Distributable Cash Flow

97. There is a potential source of downward bias in the DCF model that affects midstream companies to a greater degree than other companies. The source of the downward bias is that net income, i.e., earnings or free cash flow both underestimate the amount of cash available for distribution by midstream companies. Free cash flow is net income plus depreciation and amortization minus capital investment minus changes in working capital. In the DCF model, depreciation and capital expenditures are assumed to be equal and it is assumed that there is no change in working capital so that net income, *i.e.*, earning per share reflects all of the cash to be considered in the model.

98. Distributable cash flow (DistCF) differs from the traditional estimate of free cash flow primarily for two reasons. First, book depreciation is not a good estimate of economic depreciation for today's natural gas pipelines. DistCF recognizes that economic depreciation is less than book depreciation because the capital needed for maintenance of the pipeline system (i.e., economic depreciation) is lower than the depreciation based

upon the book life of the assets. Although this difference will reverse in the long-term, long term could be very long. The second main difference is the difference in cash taxes and book taxes. Again, until the difference reverses, cash taxes are substantially lower than book taxes, and the reversal is also likely to be far into the future due to the ongoing nature of the business. As the company invests in additional capital assets, the reversal of the difference in free cash flow and DistCF is further delayed. The result is that DistCF is a metric followed extensively by financial analysts and relied upon to a greater extent than estimates of EPS,[19] which means that DistCF is likely to be more important to investors than EPS, although both are important.

99. Theoretically, differences in timing of cash flows will reverse over the long term. For example, differences in tax depreciation versus GAAP depreciation will zero out over the depreciable life of the asset. Additionally, the fact that maintenance capital is less than book depreciation will reverse over time when book depreciation for an asset is exhausted. For most midstream companies with ongoing capital investments, the time for reversal will likely be far into the future. DistCF will likely substantially exceed free cash flow for an extended time even though the differences will reverse in the long term, but the long-term could be very long.

100. If DistCF exceeds free cash flow for an extended period, what is the likely effect on the DCF model? Because the constant growth DCF model assumes that retained earnings are the source of EPS growth, [20] EPS understates the amount of cash available for capital

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[19] "A Review of Midstream/MLP Trends & Statistics," *Midstream Monthly Outlook*: June 2019, Wells Fargo Securities.

[20] This discussion does not consider the additional growth available from issuing equity at a market price greater than book value.

investment, dividend payments, share repurchases, or debt retirement relative to DistCF. Financial analysts are aware of DistCF and likely make their estimates of EPS growth with DistCF in mind, which means that DistCF is considered in EPS growth rate forecasts. The effect of DistCF on the DCF model is likely to be downward bias in the forecast of dividend growth in the long term.

101. Why is the likely effect of DistCF on the DCF model an effect on dividends? In the DCF model, growth in EPS is assumed to be equal to the ROE times the retention ratio (i.e. 1-payout ratio) which is the amount of reinvestment per share. The model assumes that the ROE is constant for all periods into the future and that the growth of dividends is equal to the growth in EPS because the payout ratio is assumed to be constant. The FERC two-step model is based upon the assumption that the company's growth slows and converges on a sustainable level of growth equal to the forecast growth in GDP. The problem for the models is that as growth slows, the payout ratio can increase because investment needed to fund slower growth decreases. As a result, dividends are likely to grow faster than assumed in the model. The difference in DistCF and free cash flow (or EPS) means that the problem is larger earlier in the convergence to GDP growth.

102. INGAA's proposed solution is to include a term for distributable cash flow yield in the DCF calculation. A firm cannot grow faster than GDP over the long-term as a theoretical matter. However, in the transition to a growth rate equal to GDP, the need to reinvest in productive assets is reduced so that cash available for dividends increases.[21] The time

[21] It is perhaps easiest to envision the concern by considering an abrupt decrease in growth form the 3-5 year forecast to the GDP forecast. In such a case, there will be a "one-time" increase in the dividend payment due to the reduced investment required to maintain growth at the GDP rate. Dividend growth from that point will be at the rate of GDP growth, but the higher level of dividends will be maintained.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

when the difference in free cash flow and DistCF reverses is likely to be so far in the future that the present value of potentially slower growth in dividends is greatly offset by the present value of expected dividends received much earlier.

7. Share Repurchases

103. Companies sometimes repurchase outstanding shares of stock and this practice has become increasingly common in recent years.[22] From investors' point of view, this is equivalent in many ways to a dividend payment because investors receive cash in the form of dividends or in the form of repurchased shares. Ignoring share repurchases underestimates the company's dividend yield. Not all sample companies repurchase shares every year. However, when a company forecasts that it will repurchase shares, the effect should be included in the dividend yield calculation. This is true when estimating the expected market return using the dividend valuation model (see *Section V* for the discussion on estimating the MRP) as well as when estimating a sample company's ROE.

104. If share repurchase is ignored, a source of cash to investors will be omitted, and dividend yield will be understated. Companies can return value to investors through dividends, share repurchases, reinvestment in the firm, repurchases of debt or a combination of these. The theory of the dividend valuation model captures the effect of all uses of funds except share repurchases. Net repurchases of stock and debt should be considered by financial analysts when making their EPS growth rate forecasts because fewer shares of

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[22] See, for example, "Dividends and Buybacks" S&P 500 Buyback Index Outperforms," April 2019 by S&P Dow Jones Indices.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

stock outstanding means that earnings re divided by fewer shares and debt repurchase means less interest expense. However, the cash leaving the firm for share repurchase is not captured by the model. This failure has been noticed by economists, and adjustments to the model have been proposed.[23]

105. The way to capture the effect of share repurchases in the DCF model is to adjust the dividend yield for the dollars forecast to be spent on share repurchase. The adjustment is simply to add an additional term to the dividend yield when the sample company forecasts net share repurchases. The adjustment adds the value of the shares repurchased to the dividend yield in the model. The total dollar amount of the shares repurchased is equal to the number of shares repurchased times the purchase price. The adjusted dividend yield term is (total dollars of shares repurchased)/(price of shares times shares outstanding before repurchase) which is added to the standard dividend yield term.

$$\text{Adjustment to the dividend yield} = (SH_{Rp} * P_S)/(SH_{OUT} * P_S)$$

Where SH_{Rp} = Shares repurchased,

SH_{Out} = Total shares outstanding before repurchase, and

P_S = Price of shares repurchased.

106. If the price at which shares are forecast to be repurchased is the same as the market price in the standard dividend yield term, i.e., P_S, the adjustment simply becomes the ratio of the number of shares repurchased to the number of shares outstanding prior to

[23] "Stock Price Volatility, Ordinary Dividends, and Other Cash Flows to Shareholders," Lucy F. Ackert and Brian F. Smith, *The Journal of Finance*, Vol. XLVIII, No. 4, September 1993, "Valuation with the Discounted Dividend Model when Corporations Repurchase," Douglas J. Lamdin, *Financial Practice and Education*, Spring/Summer 2000, and "Estimating the Cost of Equity for Corporations That Repurchase: Theory and Application, Douglas J. Lamdin, The Engineering Economist, Vol. 46, Number 1, 2001.

repurchase. So, a company forecasting repurchase of 1 percent of outstanding shares, would have its dividend yield increased by 1 percent in recognition of the cash flow leaving the firm in a form other than dividends.

$$\text{Adjustment to the dividend yield} = \quad = \frac{SH_{Rp}}{SH_{Out}}$$

107. If INGAA's proposal on the recognition of DistCF is accepted, then an adjusted for share repurchase would not be warranted because DistCF includes the cash that would be available for share repurchase. If INGAA's proposal is not accepted, the effect of share repurchase should be added to the FERC two-step DCF model.

VII. <u>Expected Earnings Method</u>

108. With regard to the Expected Earnings method, the Commission asks:[24]

Question B3: Given the tendency of the Expected Earnings methodology to produce more high-end outliers than the other methodologies, would there be a sufficient number of natural gas and oil pipeline proxy members to implement the Expected Earnings methodology for gas and oil pipelines?

109. Whether there are sufficient sample companies to implement the Expected Earnings method depends, of course, on the criteria for inclusion in the sample of comparable risk companies. INGAA has proposed a modification to the sample selection process that if implemented would expand the sample size in natural gas pipeline cases.

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[24] NOI, p. 22.

110. *Question H.2.c.1: Should the use of utilities in the proxy group for the Expected Earnings model be predicated on the Expected Earnings analysis being forward-looking?*

111. *H.2.c.2: What, if any, concerns regarding circularity are there with using the Expected Earnings analysis to determine the base ROE, as opposed to using the analysis for corroborative purposes?*

112. *H.2.c.2.i.: If there are circularity concerns, are there ways to mitigate these concerns for the Expected Earnings analysis? If these concerns exist, are these concerns more significant than those surrounding the DCF methodology, which effectively separates Expected Earnings and ROE into its dividend yield and growth rate subcomponents?*[25]

113. The Expected Earnings method should be based upon forward-looking analysis. Below I discuss the circularity problem with regard to historical, realized accounting returns.

114. I recommend that the Commission implement the Expected Earnings method in the same manner it was done in the *Coakley* Briefing Order. Specifically, the Expected Earnings method uses the expected or forecast return on book equity as provided by *Value Line*. The forecast used is the expected ROE 3 to 5 years in the future. Because the forecast is assumed to be an ROE based upon the company's book equity at the end of the year, an adjustment is needed to convert the forecast ROE to the average book value of equity over the year. The adjustment used is to multiply the forecast ROE by an adjustment factor equal to 2*(1 + 5-yr. change in equity)/ (2 + 5-yr. change in equity).

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[25] NOI, p. 31.

115. A weakness of the Expected Earnings estimates is that they are not based upon market information. They are accounting-based estimates derived by *Value Line's* equity analysts, but they have the advantage of being a book rate of return. This is the only method among the three methods I propose for interstate pipelines that provides a return on the book value of equity, and in that sense is comparable to the allowed return on rate base that is measured on a book value basis.

116. Some have asserted that Expected Earnings method is inherently circular, just as is the Comparable Earnings method when applied to regulated companies. This is not entirely true. It is true that the expected earnings data published by analysts such as *Value Line* are accounting data and may be influenced by the allowed rates of returns determined by regulatory commissions, but that is not a sufficient reason to declare a model entirely circular and useless.

117. Consider how circularity works for the Comparable Earnings model which relies upon historical realized returns if regulated companies are used in the sample. Under fair regulation, a utility should be expected to earn its allowed ROE. Fair regulation simply means that the utility expects to earn its allowed ROE on average. A review of accounting returns would then likely show that the allowed ROE was achieved on average. Setting the allowed ROE based upon the realized accounting returns of regulated companies would result in that return being "locked" in regardless of market or industry conditions. It would not change with economic conditions but would largely depend upon what had been the allowed ROE in the past. One flaw in the Comparable Earnings model is that the model is circular if applied to a sample of regulated companies. As a result of that concern, analysts who rely upon Comparable Earnings select a sample of non-regulated

companies based normally upon a series of metrics related to the risk of the sample company. The challenge of the Comparable Earnings method when applied to non-regulated companies is to select a sample that others agree to be of comparable risk to a natural gas pipeline, making Comparable Earnings a method that is tough to convince a regulator to rely upon. Similarly, if an industry becomes more or less risky, the Comparable Earnings method would not capture this as it would rely on historical returns.

118. An issue is whether the Expected Earnings method is circular for the same reasons that the Comparable Earnings method is circular. The answer is no. First, the allowed rates of returns, that may influence analysts' expectations of future return on the book equity of a company, are one of several variables considered by analysts when forecasting expected return. Allowed returns are themselves a result of a variety of financial models and information that are market-based. The Expected Earnings method would be circular if you believed that expected returns forecast by analysts depend entirely or almost entirely on allowed returns. Even if allowed returns are one factor, it is unlikely to be the only factor considered by analysts. In contrast, for Comparable Earnings using regulated companies, the sole factor to set allowed ROE is the realized accounting return, so historical Comparable Earnings is circular.

119. Second, the expected returns used in the model are 3-5 years in the future which (currently about 2021 to 2023) disrupts the potential circularity because that future period is less affected by current events. In other words, if economic conditions change, the expected earnings estimate is likely to change even though the allowed ROE has not changed, because the analyst will try to forecast the effect of the changed economic

conditions now and in the future on expected earnings. The result is that expected earnings could be quite different from current allowed returns. In addition, to the extent that the Expected Earnings method is one of three or four used to estimate the allowed return, its impact and potential circularity are substantially reduced.

120. For natural gas pipelines Expected Earnings represents a third model to add to the DCF model and the CAPM.

121. In conclusion, I acknowledge that the Expected Earnings method has no theoretical basis as a means of estimating the market cost of capital. It is an accounting rate of return, not a market-based estimate. It is a return sourced from a single *Value Line* analyst, does not change quickly with market conditions, and has a potential element of circularity if regulated companies are included in the sample. However, it does provide a return on a book value of equity which is comparable to a regulated ROE on a book value rate base. It represents additional information available to investors for their consideration when making investment decisions and should be considered by the Commission. The Expected Earnings model addresses the capital attraction standard of *Hope*. Finally, the Commission has addressed many of these concerns in Opinion No. 551.[26]

VIII. <u>The Risk Premium Method</u>

122. Regarding the Risk Premium Model, the Commission asks:[27]

Question B2: "The Risk Premium methodology approved in Opinion Nos. 531 and 551 relied to a large extent on ROEs set forth in numerous settlements involving public

[26] 156 FERC ¶ 61,234, Docket No. EL14-12-002, Opinion No. 551, P. 230-239.

[27] NOI, p.22, and pp. 31-32,

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

utility formula rates approved by the Commission over the preceding 15 or 20 years. Natural gas and oil pipelines have stated rates and settlements of their rate cases are typically "black box" settlements that do not specify an agreed-upon ROE. How could the Risk Premium methodology be implemented in natural gas or oil pipeline rate cases where there is no history of ROE settlements from which to develop a risk premium study of the type used in Opinion Nos. 531 and 551?"

123. *Question H.2.d.1. Should the analysis be historical or forward-looking?*

124. While some variation of the Risk Premium approach may provide useful results, the Risk Premium model as applied by the *Coakley* Briefing Order cannot be applied in a natural gas pipeline proceeding because there are insufficient FERC allowed ROEs from litigated or settled pipeline rate cases.[28] The method provides a point estimate of the appropriate ROE by considering the relationship between FERC allowed ROEs and a contemporaneous benchmark interest rate. The relationship is estimated through regression analysis with the allowed ROE as the dependent variable and the interest rate as the independent variable. The result is an equation which provides a current estimate of the likely FERC allowed ROE given the current yield on the benchmark interest rate.

125. The theory underlying the method is based upon the assumption that the risk of the industry is unchanged over the time period represented by the data so that the change in the required ROE, *i.e.*, the cost of capital, is fully captured by the change in the benchmark interest rate. Even if data were available for natural gas pipelines, this

[28] Since 2010, there has been only one fully litigated allowed ROE.

assumption is not valid as discussed more extensively in INGAA's introductory remarks on the risk of the interstate pipeline industry.[29]

IX. Outlier Tests

A. Commission's High-End Screen

126. I do not believe that the proposed high-end outlier test is justified or needed for the DCF model or the CAPM. The *Coakley* Briefing Order proposes to identify outliers as estimates that are less than 100 basis points (bps) greater than the yield on BBB-rated utility debt (low-end) or greater than a 1.5 multiple of the median estimate (high-end), both subject to a "natural break" analysis.[30] There is no theoretical support for a high-end outlier test of 1.5 times the median of the sample results comparable to the theoretical support for the low-end cut off of an ROE greater than the cost of debt.

127. The ROE estimation process begins with a careful selection of companies considered to be of comparable risk, so any estimate from a sample company is then appropriate for inclusion because the company is from the universe of comparable risk companies.

128. The concept underlying an outlier test is to determine whether a data point is properly included in the sample.[31] There are two concerns. First, is the data point from the appropriate universe of interest? Second, is there an error in the data?

129. A data point that appears to be an outlier should be reviewed to determine if there is a data error or if the data is not properly part of the universe from which the sample is

[29] INGAA's affidavit has a discussion of the changing risk profile of the industry.
[30] *Coakley* Briefing Order, P. 53.
[31] It has been argued that the comparable risk proxy group represents a complete universe of comparable risk companies which would eliminate the issue of whether the estimate was properly included in the set.

being taken. Simply because an observation is "unusual" is not a sufficient reason to delete the observation. Eliminating such an observation would discard valuable information about the universe from which the observation was taken.

130. The distribution of ROE estimates is likely to be skewed to the right, meaning that there are likely to be more estimates above the sample mean than below. This is logical because investors will not purchase an asset with a negative expected return, but an expected return could be relatively high. This means that estimates that appear "high" are more frequent in the estimation process.

131. Accordingly, the first step in a review of the results of the estimation process should be to check for data errors. If the sample was properly selected to be of comparable risk companies, the estimates must be part of the distribution of possible estimates for the comparable risk universe of companies.

132. Selecting a level of demarcation above the median as the high-end cut-off point (in this case, 150 percent above the median) to determine that the observation is "atypical" or "unsustainably high" is an arbitrary selection, without a fundamental underpinning in investor behavior. Most fundamentally, there is no evidence that investors generally disregard high-end estimates from any model, much less any evidence to suggest that investors rely on the proposed 150 percent of the median criterion to excise high-end estimates from pertinent models.

133. Additionally, determining the magnitude of a "natural break" versus a normal distribution of return estimates is undefined, largely subjective, and affected by the sample size. Breaks in estimates would be expected to be larger for a small sample

because the ROE estimation process provides estimates that represent a "draw" from a distribution of the cost of capital for the industry. Some estimates will be further from the mean of the distribution than others, but that does not mean that they are not valid estimates. There could be many reasons why a gap between the cost of equity estimated for two companies may (or may not) exist. Additionally, there could be a "break" between estimates in the middle of the rank ordered estimates that is as large as the break between the two highest estimates. It would be illogical to conclude that the break at the top of the list indicates an outlier while having no concern about a similar sized break elsewhere in the distribution of returns.

134. There is no basis to infer that the magnitude of any particular gap between adjacent, rank-ordered cost of equity estimates for the proxy group companies demonstrates where the boundary lies between economically logical and illogical results. Put simply, relying on the measure of dispersion from one cost of equity estimate to another to judge the reasonableness of any particular observation is arbitrary.

135. If the allowed ROE is to be based on the midpoint of the sample results, eliminating high-end outliers can have an outsized impact because the midpoint is derived from the sum of the lowest and highest ROE estimates divided by two. For the midpoint, the analysis only considers the highest and lowest estimates which means that those two estimates carry far more weight in the ROE determination than any others. The median is calculated differently. The median is calculated by ordering the ROE estimates from lowest to highest and selecting the middle value. This greatly reduces the impact of the high-end of the range of results as compared to the midpoint calculation. When relying upon the median, the magnitude of the "high" estimate has no impact on the median unless the

observation was deleted. The magnitude is meaningless; it is just above the median. Therefore, to the extent the Commission retains the high-end outlier test at all, it should retain it only for proceedings where the allowed ROE is based on the midpoint. It is for this reason that I recommend the Commission rely upon the median instead of the midpoint when setting the allowed ROE. Much of the argument about including or excluding potential sample companies revolves around companies whose estimates are high. Reliance on the median would reduce these debates.

136. For the DCF model, the FERC methodology already moderates the EPS growth rate forecasts from security analysts by weighting the forecast GDP growth rate. Previously, the Commission determined that use of a weighted-average EPS growth did not require a check on sustainability because GDP growth is by definition sustainable. This has not changed.[32]

137. Similarly, with regard to the CAPM, there is little room for unsustainable estimates because the estimates are constrained by the model to be on the Security Market Line as illustrated in Figure 1 above.

138. If the proxy group sample is of comparable risk, the CAPM estimates would not need a high-end outlier test. It is only for the expected earnings test that a high-end outlier test would have any relevance because estimates could vary if the company were recovering from an unusual event. But even for the expected earnings method, relying upon 1.5 times the median lacks theoretical support.

[32] Even if the weight placed on forecast GDP growth were changed, GDP growth is by definition sustainable.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

139. In summary, the high-end outlier test as articulated has no theoretical foundation and is not required for either the CAPM or the Commission's two-step DCF model. It is unnecessary when relying upon the median of the estimates to set the allowed ROE. The only time in which a high-end outlier test should be considered is for the expected earnings model when the ROE is set relative to the midpoint of the zone of reasonableness.

B. Commission's Low-End Screen

140. The Commission's low-end outlier has theoretical support that is lacking in the high-end outlier test. Under the proposed methodology in the ROE Briefing Orders, the Commission removes estimates that are less than approximately 100 basis points (bps) greater than the 6-month average BBB-rated utility bond yield. The Commission subjects the 100 bps demarcation to a "natural break" analysis where the 100 bps may increase slightly by considering the extent to which the excluded estimates differ from other low-end estimates of the proxy group companies.

141. The low-end test has support in basic financial theory: any company's bonds are less risky than its equity, and investors cannot be expected to purchase common stock if less risky bonds yield essentially the same expected return. Thus, analysts agree that a low-end outlier test is appropriate to eliminate estimates which are inconsistent with financial theory.

142. The 100 bps minimum spread is too low. If the beta estimate for BBB-rated debt of 0.25[33] and the minimum beta for equity is about 0.50, the minimum spread would be the difference in betas 0.25 (*i.e.*, 0.50 -0.25) times the MRP. Even for relatively low estimate of the MRP of 6 percent, the minimum spread should be 150 bps and would be even larger for a higher MRP.

143. However, the minimum spread over BBB-rated debt should be adjusted for the interest rate environment. It is generally acknowledged that there is an inverse relationship between the market risk premium and the level of interest rates. The MRP increases when interest rates decrease and decreases when interest rates rise. Similarly, the minimum spread over BBB-rated debt should similarly be adjusted, although 150 bps should be the minimum. One way to adjust the minimum threshold would be to use 0.25 times the estimate MRP plus the current yield on BBB-rated utility debt.

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[33] Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, "Explaining the Rate Spread on Corporate Bonds," *The Journal of Finance*, February 2001, pp. 247 277 estimate the beta of BBB-rated debt to 0.26.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

QUALIFICATIONS OF MICHAEL J. VILBERT

Dr. Michael J. Vilbert is a Principal Emeritus in The Brattle Group's San Francisco office and has more than 20 years of experience as an economic consultant. He 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. In the area of regulatory economics, he has testified or submitted testimony on the cost of capital for regulated companies in the water, electric, natural gas and petroleum industries in the U.S. and Canada. His testimony has addressed the effect of regulatory policies such as decoupling or must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for companies organized as Master Limited Partnerships. He analyzed issues associated with situations imposing asymmetric risk on utilities, the prudence of purchased power contracts, the economics of energy conservation programs, the appropriate incentives for investment in electric transmission assets and the effect of long-term purchased power agreements on the financial risk of a company. He has served as a neutral arbitrator in a contract dispute and analyzed the effectiveness of a company's electric power supply auction. He has also estimated economic damages and analyzed the business purpose and economic substance of tax related transactions, valued assets in arbitration for purchase at the end of the contract, estimated the stranded costs of resulting from the deregulation of electric generation and from the municipalization of an electric utility's distribution assets and addressed the appropriate regulatory accounting for depreciation and goodwill.

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

- Dr. Vilbert served as the consulting expert in several cases for the U.S. Department of Justice and the Internal Revenue Service regarding the business purpose and economic substance of a series of tax related transactions. These projects required the analysis of a complex series of financial transactions including the review of voluminous documentary evidence and required expertise in financial theory, financial market as well as accounting and financial statement analysis.

- 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'=

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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 Awhat 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

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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.

- Dr. Vilbert evaluated the appropriate Abareboat@ charter rate for an oil drilling platform for the renewal period following the end of a long-term lease. The evaluation required analysis of the market for oil drilling platforms around the world including trends in construction and labor costs and the demand for platforms in varying geographical environments.

- Dr. Vilbert and Dr. Villadsen, also of The Brattle Group, evaluated the offer to purchase the assets of Pentex Alaska Natural Gas Company, LLC on behalf of the Western Finance Group for presentation to the Board of the Alaska Industrial Development and Export Authority. The report compared the proposed purchase price with selected trading and transaction multiples of comparable companies.

PRESENTATIONS

"Moving Toward Value in Utility Compensation – Shareholder Value Concept," with A. Lawrence Kolbe, California PUC Workshop, June 13, 2016.

"Natural Gas Pipeline FERC ROE," INGAA Rate of Return Seminar, with Mike Tolleth, March 23, 2016.

"The Cost of Capital for Alabama Power Company," Public Service Commission public meeting, July 17, 2013.

"An Empirical Study of the Impact of Decoupling on the Cost of Capital," Center for Research in Regulated Industries, Shawnee on Delaware, PA, May 17, 2013.

"Point – Counterpoint: The Regulatory Compact and Pipeline Competition," with (Jonathan Lesser, Continental Economics), Energy Bar Association, Western Meeting, February 22, 2013

"Introduction to Retail Rates," presented to California Water Services Company, 18-19 November

2010.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", National Association of Water Companies: New York Chapter, Albany, NY, May 21, 2009.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", New York Public Service Commission, Albany, NY, April 20, 2009.

ACurrent Issues in Explaining the Cost of Capital to Utility Commissions@ Cost of Capital Seminar, Philadelphia, PA, 2008.

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

ACurrent Issues in Estimating the Cost of Capital,@ *EEI Electric Rates Advanced Course*, Madison, WI, 2006, 2007, 2008, 2009, 2010 and 2011.

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

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

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

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PUBLICATIONS

Risk and Return for Regulated Industries, The Brattle Group, Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, Elsevier Academic Press, Cambridge, MA, 2017.

"Effect on the Cost of Capital of Ratemaking that Relaxes the Linkage between Revenue and kWh Sales: An Updated Empirical Investigation of the Electric Industry," Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang, and James Hall, *The Brattle Group*, November 2016.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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"The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation," prepared for The Energy Foundation by Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, March 20, 2014.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, Bente Villadsen, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the Australian Energy Regulator and the Economic Regulation Authority, Western Australia, February 2013.

"Survey of Cost of Capital Practices in Canada," (with Bente Villadsen and Toby Brown), prepared for British Columbia Utilities Commission, May 2012.

"Impact of Portland Harbor Remediation Costs on City of Portland Water and Sewer Rates," with Professor David Sunding, March 2012.

"The Impact of Decoupling on the Cost of Capital – An Empirical Study," Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown, Discussion Paper, *The Brattle Group*, March 2011, revised July 2012.

"Review of Regulatory Cost of Capital Methodologies," (with Bente Villadsen and Matthew Aharonian), Canadian Transportation Agency, September 2010.

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

"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.

"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.

"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.

TESTIMONY

Direct testimony before the California Public Utilities Commission on behalf of Pacific Gas and Electric Company (PG&E) on the cost of capital for PG&E's electric utility assets in the Cost of Capital 2020 proceeding, Application 19-04-___(U 39 M), April 2019.

Prepared affidavit (with Akarsh Sheilendranath) on behalf of Constellation Mystic Power, LLC, Docket No. ER18-1639-000, on the cost of capital for the Mystic reliability must run generating using the revised FERC ROE estimation methodology, April 2019.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Electric Company, Case No. U-20162, on the cost of common equity capital for DTE Electric Company's regulated electric utility assets, June 2018 and November 2018.

Direct and supplemental testimony before the Public Utilities Commission of Ohio on behalf of Vectren Energy Delivery of Ohio, Inc., Case No. 18-0298-GA-AIR, on the cost of capital for Vectren's gas local distribution assets, April 2018 and November 2018.

Direct and rebuttal testimony before the Public Utilities Commission of the State of Hawai'i on behalf of Young Brothers, Limited, Docket No. 2017-0363, on the cost of capital for Young Brothers regulated intrastate barge operations, March 2018 and September 2018.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Gas Company, Case No. U-18999, on the cost of common equity capital for DTE Gas Company's regulated natural gas distribution assets, February 2018 and April 2018.

Supplemental testimony before the Public Utilities Commission of the State of Hawai'i on behalf of Hawaiian Electric Company, Inc., Docket No. 2016-0328, with regard to the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales, February 2018.

Direct and rebuttal testimony before the Public Utilities Commission of the State of Hawai'i on behalf of Maui Electric Company, Limited, Docket No. 2017-0150, with regard to the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales, October 2017 and May 2018.

Rebuttal testimony before the California Public Utilities Commission on behalf of California-American Water Company, Application 15-07-019, Phase 3A and Phase 3b, on the economic effect on the Company and the applicability of a fine based upon California-American Water Company's administration of its tariff for the Monterey Water District, August 2017.

Direct and rebuttal testimony before the Corporation Commission of Oklahoma on behalf of Public Service Company of Oklahoma, Cause No. PUD201700151, on the cost of capital for Public Service Company of Oklahoma's regulated assets, June 2017 and October 2017.

Direct and rebuttal testimony before the California Public Utilities Commission on behalf of California Water Services Company, Application No. A.1704-006, on the cost of capital for California Water Services Company's regulated assets, April 2017 and August 2017.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Electric Company, (Case No. U-18255) on the cost of common equity capital for DTE Electric's regulated electric assets, April 2017 and September 2017.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. RP17-598-000 on behalf of Great Lakes Gas Transmission Limited Partnership, regarding the

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

appropriate ROE to allow for its regulated natural gas pipeline assets, March 2017.

Prepared direct testimony before the North Carolina Utilities Commission, Docket No. G-39, Sub 38, on behalf of the Cardinal Pipeline Company, LLC regarding the appropriate allowed ROE for the Company's pipeline assets, March 2017.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. ER17-706-000 on behalf of Gridliance West Transco LLC, regarding Gridliance West's application pursuant to section 205 of the Federal Power Act regarding the appropriate ROE, cost of debt, and capital structure to allow Gridliance West Transco LLC to earn on the transmission facilities acquired from Valley Electric Association, December 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. EC17-049-000, on behalf of Gridliance West Transco LLC, regarding GridLiance West's application pursuant to section 203 of the Federal Power Act (FPA) to acquire certain high voltage transmission facilities from Valley Electric Transmission Association, LLC (VETA) through its parent non-profit electric cooperative parent Valley Electric Association, Inc. (Valley Electric), December 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. ER16-2632-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE and capital structure to allow for its regulated electric transmission assets, September 2016.

Prepared direct and rebuttal testimony before the Public Utilities Commission of Hawaiʻi on the effect on the cost of capital of decoupling ratemaking that relaxes the linkage between revenue and kWh sales on behalf of Hawaiʻi Electric Light Company, Inc. Docket No. 2015-0170, August 2016 and June 2017.

Direct testimony before the Michigan Public Service Commission on behalf of the Detroit Thermal, LLC (Case No. U-18131) on the cost of common equity capital for Detroit Thermal's regulated steam service, July 2016.

Pre-filed direct testimony and supporting exhibits before the Rhode Island Public Utilities Commission on behalf of The Narragansett Electric Company d/b/a National Grid Docket No. 47xx regarding Petition for the Approval of Gas Capacity Contracts and Cost Recovery, June 2016.

Prepared direct testimony and supporting exhibits before the Federal Energy Regulatory Commission, Docket No. RP16-440-000, on behalf of ANR Pipeline Company, regarding the appropriate ROE to allow for its regulated natural gas pipeline assets, January 2016.

Pre-filed direct testimony before the Massachusetts Department of Public Utilities on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid regarding the risk transfer inherent in signing long-term contracts for natural gas pipeline capacity, Docket No. D.P.U. 16-05, January 2016.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

DTE Electric Company (Case No. U-18014) on the cost of capital for DTE Electric Company's regulated electric assets, January 2016 and July 2016.

Rebuttal testimony before the Public Utility Commission of Texas on behalf of Ovation Acquisition I, L.L.C., Ovation Acquisition II, L.L.C., and Shary Holdings, L.L.C. concerning the adequacy of Oncor Electric Distribution Company's (Oncor) liquidity, access to capital and financial risk with regard to the proposed restructuring of Oncor, PUC Docket No. 451888, December, 2015.

Direct and rebuttal testimony before the Michigan Public Service Commission on behalf of the DTE Gas Company (Case No. U-17799) on the cost of capital for DTE Gas Company's natural gas distribution assets, December 2015 and May 2016.

Prepared direct testimony before the Federal Energy Regulatory Commission, Docket No. ER15-2594-000, on behalf of South Central MCN, LLC, regarding the appropriate ROE to include in the transmission rate formula (Formula Rate) to establish an annual transmission revenue requirement (ATRR) for transmission service over facilities that SCMCN will own in the Southwest Power Pool, Inc. (SPP) region, September 2015.

"Report on Gas LDC multiples," with Bente Villadsen, *Alaska Industrial Development and Export Authority*, May 2015.

Direct and reply testimony before the Regulatory Commission of Alaska on behalf of Cook Inlet Natural Gas Storage Alaska, LLC, Docket No. U-15-016 on the appropriate allocation of the proceeds from the sale of excess Found Native Gas discovered incidental to the construction of the storage facility, April 2015 and July 2015.

Direct testimony before the Michigan Public Service Commission on behalf of the Detroit Edison Electric Company (Case No. U-17767) on the cost of capital for DTE's electric utility assets, December 2014.

Direct and rebuttal testimony before the Washington Utilities and Transportation Commission on behalf of Puget Sound Energy, Inc. Docket Nos. UE-130137 and UG-130138 (consolidated) remand proceeding with regard to the effect of decoupling on the cost of capital, November 2014 and December 2014.

Initial and Reply Statement of Position before the Public Utilities Commission of Hawaiʻi In the Matter of Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaiʻi Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 2013-0141, with Dr. Toby Brown and Dr. Joseph B. Wharton, May 2014 and September 2014.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission on behalf of Metropolitan Edison Company (Docket No. R-2014-2428745), Pennsylvania Electric Company (Docket No. R-2014-2428743), Pennsylvania Power Company (Docket No. R-2014-2428744), and West Penn Power Company (Docket No. R-2014-2428742) regarding the appropriate cost of common equity for the companies, September 2014 and December 2014.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 14-0828-EL-UNC, May 2014.

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Expert Report, with A. Lawrence Kolbe and Bente Villadsen, on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of the behalf of oil pipeline in arbitration, April 2013.

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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Direct testimony and supporting exhibits on behalf of Transcontinental Gas Pipeline Company, LLC, before the Federal Energy Regulatory Commission, on the Cost of Capital for Interstate Natural Gas Pipeline assets, Docket No. RP12-993-000, August 2012.

Direct Testimony before the North Carolina Utilities Commission on behalf of Cardinal Pipeline Company LLC, regarding the cost of capital for an intrastate natural gas pipeline, Docket G-39, Sub 28, August 2012.

Joint Rebuttal Testimony before the California Public Utility Commission on behalf of California American Water Company, regarding Application of California-American Water Company (U210W) for Authorization to increase its Revenues for Water Service, Application 10-07-007, and In the Matter of the Application of California-American Water Company (U210W) for an Order Authorizing and Imposing a Moratorium on New Water Service Connections in its Larkfield District, Application 11-09-016, August 2012.

Direct testimony before the Public Utilities Commission of Ohio, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2011 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 12-1544-EL-UNC, May 2012.

Deposition testimony in *Tahoe City Public Utility District, Plaintiff vs. Case No. SCV 27283 Tahoe Park Water Company, Lake Forest Water Company, Defendants*, May 2012.

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Rebuttal testimony before the Florida Public Service Commission, Docket No. 110138-EL, on behalf of Gulf Power, a Southern Company, on the method to adjust the return on equity for differences in financial risk, November 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER12-296-000, on behalf of Public Service Electric and Gas Company on the Cost of Capital and for Incentive Rate Treatment for the Northeast Grid Reliability Transmission Project, October 2011.

20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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Rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.10-09-018, on behalf of California American Water Company, on Application of California American Water Company (U210W) for Authorization to Implement the Carmel River Reroute and San Clemente Dam Removal Project and to Recover the Costs Associated with the Project in Rates, June 2011.

Direct and rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.11-05-001, on behalf of California Water Service Company, on the Cost of Capital for Water Distribution Assets, April 2011 and September 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER11-013-000, on behalf of the Atlantic Wind Connection Companies, on the Cost of Capital and Cost of Capital incentive adders for Electric Transmission Assets, December 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. RP11-1566-000, on behalf Tennessee Gas Pipeline Company, on the Cost of Capital for Natural Gas Transmission Assets, November 2010.

Direct and rebuttal testimony before the Michigan Public Service Commission, In the matter of the application of The Detroit Edison Company, for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, Case No. U-16472, October 2010 and April 2011.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP10-1398-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, September 2010 and September 2011.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 10-1265-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2009 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, September 2010.

Direct testimony before the Michigan Public Service Commission, Case No. U-16400, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, July 15, 2010.

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-681-000, on behalf of Green Power Express, LLP, on the Cost of Capital for Electric Transmission Assets, February 2009.

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Written and Reply Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of AltaGas Utilities Inc., November 2008 and May 2009.

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Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No. 08-1783-G-PC, on behalf of Dominion Hope Gas Company concerning the Cost of Capital for Gas Local Distribution Company assets, November 2008 and May 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-249-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for Mid-Atlantic Power Pathway Electric Transmission Assets, November 2008.

Direct and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, with regard to the test to determine Significantly Excessive Earnings within the context of Senate Bill No. 221, September 2008 and October 2008.

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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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.

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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.

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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 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.

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.

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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.

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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

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.

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.

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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, Application No. 1271597, July 2003, November 2003, Decision 2004-052, dated July 2004.

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.

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20190626-5309 FERC PDF (Unofficial) 6/26/2019 4:27:14 PM

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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.

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Document Content(s)