

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southwest Gas Storage Company)
) Docket No. RP07- -000
)

**PREPARED DIRECT TESTIMONY
OF
ROBERT B. HEVERT**

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Robert B. Hevert, and I am President of Concentric Energy Advisors, Inc. (“CEA”), located at 313 Boston Post Road West, Suite 210, Marlborough, Massachusetts 01752.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Southwest Gas Storage Company (“Southwest Gas Storage” or the “Company”).

Q. Please describe your experience in the energy and utility industries.

A. I have previously served as an executive and manager with other consulting firms (*i.e.* REED Consulting Group and Navigant Consulting, Inc.), and as a financial officer of Bay State Gas Company. I have provided testimony regarding strategic and financial matters, including the cost of capital, before several state utility regulatory agencies and the Federal Energy Regulatory Commission (the “FERC” or the “Commission”), and have advised numerous energy and utility clients on a wide range of financial and economic issues including both asset and corporate-based transactions. Many of those assignments have included the determination of the cost

1 of capital for transaction and valuation purposes. A summary of my professional
2 and educational background is provided in Exhibit No. SGS-65 to my Direct
3 Testimony.

4 **Q. Please describe CEA's activities in energy and utility engagements.**

5 A. CEA provides financial and economic advisory services to a large number of energy
6 and utility clients across North America. Our financial advisory activities include buy
7 and sell-side merger, acquisition and divestiture engagements; due diligence and
8 valuation engagements, including the provision of fairness opinions; project and
9 corporate finance services; and transaction support services. Our economic and
10 market analysis services include utility ratemaking and regulatory advisory services,
11 energy market assessments, market entry and exit analysis, and energy contract
12 negotiations.

13 **II. PURPOSE AND OVERVIEW OF TESTIMONY**

14 **Q. What is the purpose of your testimony?**

15 A. The purpose of my testimony is to present evidence and provide a recommendation
16 regarding the Company's return on equity ("ROE"). My analyses and
17 recommendations are supported by the data presented in Exhibit Nos. SGS-66
18 through SGS-78.

19 **Q. What are your conclusions regarding the appropriate ROE for Southwest Gas**
20 **Storage?**

21 A. Based on my analyses, I have concluded that the Company should be provided the
22 opportunity to earn a ROE in the range of approximately 11.00 percent to
23 approximately 13.60 percent. Taking into consideration the relative level of business

1 risk faced by the Company, I recommend an equity cost rate of 13.00 percent. This
2 equity return will adequately compensate investors for their investment in the capital
3 of the Company and will provide the Company with the opportunity to attract new
4 capital on reasonable terms.

5 **Q. Please provide a brief overview of the analyses that led to your conclusions.**

6 A. Consistent with Commission precedent, my analyses and recommendation are based
7 primarily on the two-stage Discounted Cash Flow ("DCF") model. My application
8 of the DCF model and analytical results are based on third-party analyst growth
9 projections, as well as market-based information including current annual dividends
10 (or distributions), and recent stock (or unit) prices. In applying and assessing the
11 results of my DCF analyses, I considered certain costs and trends, including the
12 fundamental business risks currently facing the natural gas pipeline industry in
13 general and the Company in particular. In addition, I have reviewed my DCF results
14 relative to other widely used ROE estimation methodologies and benchmarks.

15 The Commission, Southwest Gas Storage and other interstate gas companies are at a
16 crossroads in re-evaluating the methodologies employed in their application of the
17 DCF model for purposes of determining ROE. As a result of industry
18 consolidation, financial instability, and diminished involvement in regulated interstate
19 gas pipeline operations, the historical proxy group no longer provides a reasonable
20 comparison for a financially stable interstate gas pipeline. As a practical matter, there
21 is only one corporate pipeline company (the Williams Companies) that possibly
22 could be considered a proxy for Southwest Gas Storage. Moreover (as discussed in
23 more detail later in my testimony), natural gas Local Distribution Companies

1 (“LDCs”) in general, and the three LDCs used as comparison companies in recent
2 FERC proceedings in particular, recently have been trading at unusually high
3 valuation multiples with correspondingly low dividend yields. Consequently, DCF
4 results based on those companies are inherently biased. In fact, based on current
5 market data, DCF results for the three LDC’s are substantially below returns that
6 have recently been authorized (on average for natural gas pipelines). Under these
7 conditions, in which there is no viable corporate pipeline proxy group and the
8 potential LDC proxy companies render unreasonable DCF results, it is necessary to
9 consider alternative approaches to estimating the Company’s ROE. As such, I have
10 relied upon multiple analytical approaches, and for the reasons discussed later in my
11 testimony, have incorporated certain Master Limited Partnerships (“MLPs”) in my
12 analysis.

13 The need to consider MLPs as proxy entities also has been addressed in a recent
14 INGAA white paper, in which the process used by the Commission to establish
15 ROEs for natural gas pipelines was examined, particularly in the following three
16 areas: (1) the Commission’s past practice, (2) the implications of excluding MLPs
17 from a DCF analysis of interstate gas companies; and (3) the shortcomings of the
18 DCF analysis in itself. INGAA’s concluding statement with respect to the treatment
19 of MLPs is a fair summary of the industry’s position on this issue:

20 This report does not suggest that the DCF methodology is so flawed
21 that the Commission should cease using it to calculate pipeline
22 returns. But the Commission must recognize the increasingly
23 important role that MLPs play in the interstate pipeline industry by
24 including an appropriate mix of MLPs in the proxy group...¹

¹ INGAA, *Allowed Returns on Equity in the Interstate Gas Pipeline Industry Issues and Options Regarding the FERC DCF Approach*, dated August 24, 2006, at 6.

1
2 The Commission likewise has recognized that there are an insufficient number of
3 publicly traded pipeline corporations to form a reasonable proxy group and as such,
4 has allowed the use of LDCs as proxies for pipeline companies. The Commission
5 also found, however, that “LDCs face lower risks (relative to interstate pipelines) due
6 to the nature of their operations.”² Since the DCF results for the LDCs are well
7 below other observable, practical benchmarks, the use of natural gas LDCs as
8 proxies for a pipeline would create a significant downward bias in the determination
9 of the Company’s ROE. Consequently, it now is extremely important to consider
10 alternative methodologies and proxy entities when determining the appropriate ROE
11 for Southwest Gas Storage.

12 **Q. Does the Commission oppose the inclusion of MLPs in the proxy group that**
13 **is relied upon to establish the appropriate return on equity for a natural gas**
14 **pipeline?**

15 A. No. In its recent *Kern River* decision, the Commission noted that while MLPs were
16 not included in the proxy group in that proceeding they were “not making a generic
17 finding that MLPs cannot, in future cases, be considered for inclusion in the proxy
18 group if a proper evidentiary showing is made”.³ Rather, the Commission stated that
19 in order for MLPs to be included in the proxy group, it would be necessary to
20 demonstrate that “distributions used as the ‘dividend’ include(s) only a payment of
21 earnings and not a return of investment”.⁴ The Commission’s concern appears to be

² See *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 (2006) at 72. Clarification added.

³ *Kern River*, p. 63.

⁴ *HIOS*, 110 FERC at p. 126.

1 that, to the extent that MLP distributions include a return of capital, both the yield
2 and growth components of the DCF model may be biased:

3 If the growth forecasted for an MLP comes from external capital, it is
4 necessary either (1) to explain why the external sources of capital do
5 not distort the DCF result for that MLP, or (2) propose an
6 adjustment to the DCF analysis to eliminate any distortion.⁵
7

8 More recently, the Commission invited interested parties to provide comments
9 regarding the inclusion of MLPs in proxy groups, or an alternative calculation to the
10 DCF as a method of determining the return on equity.⁶

11 **Q. Have you performed any analyses to address the Commission's concern in**
12 **that regard?**

13 A. Yes. As discussed in more detail later in my testimony, I first analyzed whether
14 projected distributions are expected to be paid out of operating cash flows (including
15 distributions to the General Partner). In each case for which such projections were
16 available, I found that distributions were expected to be made entirely from internally
17 generated funds. Based on that analysis, I concluded that the MLP distribution
18 yields were not biased by the source of funds underlying the projected distributions.
19 In order to address the Commission's concern that the comparatively high MLP
20 yields (relative to corporate entities) did not unduly "distort" the expected growth
21 rates, I compared the relative contributions of the yield and growth components to
22 the DCF results for a proxy group of MLPs, the Williams Companies (which, as
23 discussed later herein, is the sole corporate pipeline company that is eligible to be
24 included as a proxy company) and the three LDCs referenced in *Kern River*. As

⁵ *Kern River*, paragraph 152.

⁶ 118 FERC ¶ 61,252 (2007).

1 expected, the growth component represented a substantially smaller portion of the
2 DCF result for the MLPs relative to the corporate entities. I concluded, therefore,
3 that the MLP distribution yields appropriately result in lower expected growth rates.
4 To assess whether the MLPs' growth is more dependent on external financing than
5 the corporate companies, I examined the extent to which the analysts' consensus
6 growth estimates (as provided by I/B/E/S) exceeded the implied "sustainable
7 growth rate" (defined as the product of the earnings retained and the expected return
8 on equity) for the MLPs and corporate entities, respectively. That analysis showed
9 that analysts' growth expectations are considerably greater than the "sustainable
10 growth" estimate for both groups, indicating that external financing is a significant
11 element of expected long term growth for both MLPs and corporate entities. I
12 therefore concluded that there is no basis to assume that the consensus MLP growth
13 rates are "distorted" relative to corporate growth rates by virtue of external
14 financing.

15 Finally, in order to assess the reasonableness of the DCF results (which are based in
16 large part on a group of MLPs), I conducted a risk premium analysis based on the
17 historical relationship between Commission-authorized ROEs and concurrent long-
18 term interest rates. As discussed in more detail in Section VI, the results of that
19 analysis were highly consistent with my median DCF results, providing further
20 support for the position that the DCF results, based on a proxy group including
21 MLPs, are not biased vis-à-vis corporate entities.

1 **Q. How is the balance of your directanswering testimony organized?**

2 A. My remaining directanswering testimony is organized into five sections. Section III
3 discusses the regulatory guidelines and financial considerations pertinent to rate of
4 return estimates. Section IV discusses current economic conditions that have a
5 bearing on the determination of an appropriate rate of return. Section V discusses
6 the criteria and approach for the selection of my proxy group of comparable
7 companies. Section VI explains the data and methodologies in my analyses and my
8 recommendation of the appropriate ROE for Southwest Gas Storage. Section VII
9 summarizes my results and conclusions.

10 **III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS**

11 **Q. Please describe the guiding principles used in establishing the ROE for a**
12 **regulated utility.**

13 A. The United States Supreme Court's precedent-setting decisions in *Hope* and *Bluefield*
14 established the standards for determining the fairness or reasonableness of a utility's
15 allowed ROE. Among the standards established by the Court in those cases are: (i)
16 consistency with other businesses having similar or comparable risks; and (ii)
17 adequacy of the return to support credit quality and access to capital, while
18 maintaining financial integrity. The *Hope* and *Bluefield* cases read, in pertinent part:

19
20 A public utility is entitled to such rates as will permit it to earn a
21 return on the value of the property which it employs for the
22 convenience of the public equal to that generally being made at the
23 same time and in the same general part of the country on investments
24 in other business undertakings which are attended by corresponding
25 risks and uncertainties; but it has no constitutional right to profits
26 such as are realized or anticipated in highly profitable enterprises or

1 speculative ventures. The return should be adequate, under efficient
2 and economic management, to maintain and support its credit and
3 enable it to raise the money necessary for the proper discharge of its
4 public duties. A rate of return may be reasonable at one time and
5 become too high or too low by changes affecting opportunities for
6 investment, the money market and business conditions generally.⁷

7
8 * * *

9 Rates which are not sufficient to yield a reasonable return on the
10 value of the property used at the time it is being used to render the
11 service are unjust, unreasonable and confiscatory...⁸

12
13 * * *

14 From the investor or company point of view, it is important that
15 there be enough revenue not only for operating expenses, but also
16 for the capital costs of the business. These include service on the
17 debt and dividends on the stock. By that standard the return to the
18 equity owner should be commensurate with returns on investments
19 in other enterprises having corresponding risks. That return,
20 moreover, should be sufficient to assure confidence in the financial
21 integrity of the enterprise, so as to maintain its credit and to attract
22 capital.⁹

23
24 **Q. Why is it important for a utility to be allowed the opportunity to earn a return**
25 **adequate to attract capital at reasonable terms?**

26 **A.** There is a long history regarding the allowed return on equity, the role of capital
27 structure, and the resulting cost of capital in the establishment of just and reasonable
28 rates for utility services. Among the themes common to many Federal, State and
29 Supreme Court cases is the principle that a utility's cost of capital (including its
30 capital structure and allowed return on common equity) must be reflective of other
31 enterprises having comparable risks acting independently in the financial markets. A
32 return that is adequate to attract capital at reasonable terms enables the utility to

⁷ *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, at 692-693 (1923).

⁸ *Id.*, at 690-692.

⁹ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, at 603 (1944), ("Hope").

1 provide safe, reliable service while maintaining its financial integrity. In keeping with
2 the *Hope* and *Bluefield* standards, that return should be commensurate with the returns
3 expected elsewhere in the market for investments of equivalent risk. The
4 consequence of the Commission's order in this case, therefore, should be to provide
5 the Company with the opportunity to earn a return on equity that is: (1) adequate to
6 attract capital at reasonable terms, thereby enabling it to provide safe, reliable natural
7 gas storage service; (2) sufficient to ensure the financial integrity of the Company's
8 gas transmission operations; and (3) commensurate with returns on investments in
9 enterprises having corresponding risks. To the extent the Company is provided the
10 opportunity to earn its market-based cost of capital, neither customers nor
11 shareholders should be disadvantaged.

12 **Q. Please discuss the importance of the allowed rate of return from the**
13 **perspective of the capital markets.**

14 A. The financial community continues to put the pipeline industry under intense
15 scrutiny. There is little question, for example, that the rating agencies continue to
16 focus on financial profiles and business risks for all pipeline companies. To that
17 point, Standard & Poor's noted that:

18 When evaluating the creditworthiness of natural gas pipeline
19 companies, Standard & Poor's analysis begins with a qualitative
20 assessment of a company's business risk profile. The company's
21 financial metrics are then examined in light of its business risk
22 profile, since companies with higher business risk require stronger
23 financial metrics at the same rating category.¹⁰
24

¹⁰ Standard & Poors, "Key Rating Factors for U.S. Natural Gas Pipelines", *Commentary Report* (10 August 2005): at 1.

1 Thus, the allowed rate of return should take into consideration capital market
2 expectations relative to both earnings and risk.

3 **Q. Has the Commission recognized the importance of establishing a rate of**
4 **return that is commensurate with the risks incurred by equity investors?**

5 A. Yes, in *SoCal*, the Commission concluded that “investors generally cannot be
6 expected to purchase stock, if debt, which has less risk than stock, yields the same
7 return”.¹¹ As discussed later in my testimony, that conclusion is relevant to the DCF
8 results for certain corporate pipeline and LDC companies in this case.

9 **Q. What is the basis for your recommended ROE for Southwest Gas Storage?**

10 A. My recommended ROE is based on a proxy group of publicly-traded corporations
11 and Master Limited Partnerships with significant interstate natural gas pipeline
12 operations. My recommendation relies on a range of reasonableness, determined by
13 the high and low DCF results, and is supported by additional corroborating analyses.
14 By selecting a group of entities with risks and business characteristics comparable to
15 Southwest Gas Storage, I have ensured that my analysis in this proceeding comports
16 with the *Hope* and *Bluefield* standards upon which my recommendation is based, as
17 well as the FERC standard for natural gas pipelines, established in *Williston Basin*.¹²
18 As such, my analyses result in a recommended ROE that is both commensurate with
19 the Company’s total risk (i.e., business risk and financial risk) and sufficient to attract
20 capital at reasonable rates.

21 The Commission has stated its preference for the application of a
22 Discounted Cash Flow (“DCF”) model that incorporates both near-term earnings

¹¹ SoCal Edison, 92 FERC paragraph 61,070 at 61,266 (2002).

¹² *Williston Basin Interstate Pipeline Company*, 104 FERC ¶ 61,036 (2003).

1 growth forecasts and longer-term estimates of macroeconomic growth (referred to
2 herein as the “two-stage DCF” model). My testimony, therefore, relies heavily on
3 the two-stage DCF model. As discussed in more detail later in my testimony,
4 however, to the extent that LDCs are used as comparison companies, it will be very
5 important to consider alternative ROE estimation methodologies. As such, I have
6 performed a risk premium analysis based on FERC-authorized returns for corporate
7 gas pipeline companies. As noted earlier, the results of that analysis is consistent
8 with my median DCF results.

9 IV. CURRENT ECONOMIC CONDITIONS

10 **Q. Please describe the business environment and risks currently facing interstate**
11 **natural gas pipeline and storage companies.**

12 A. Natural gas pipeline companies are faced with a series of regulatory, business and
13 economic risks that, in aggregate, continue to exert competitive pressure, thereby
14 influencing both business and financial risks. In general, shorter contract durations,
15 counter-party credit risk, and pricing pressure resulting from the lower of cost or
16 market based rates has increased the competitive nature of the natural gas pipeline
17 business in general. Moreover, unbundling initiatives at the state jurisdictional level
18 have provided end-users and shippers with an enhanced range of competitive
19 alternatives that may enable shippers to shift risks to the pipelines by obtaining
20 shorter term contracts or releasing capacity to other shippers.

1 **Q. Is it your view that Southwest Gas Storage faces greater risk than other**
2 **interstate pipeline and storage companies?**

3 A. Yes. Based on my review of the Company's business and financial risks, Southwest
4 Gas Storage faces greater overall operating risk than other interstate pipeline and
5 storage companies. As discussed in the testimony of Mr. Langston, Southwest Gas
6 Storage faces short-term contracts, and variability of customer utilization of its
7 storage service. In addition, the Company has no diversification in its service
8 offerings, exposing the Company to significant risk if the market demand for storage
9 services were to change. Finally, the performance of the Company's storage fields
10 has fluctuated over time¹³, requiring the Company to procure additional resources to
11 meet its obligation to existing customers. The combination of variability in customer
12 usage and field performance issues places Southwest Gas Storage above the average
13 level of business risk experienced by interstate natural gas pipeline and storage
14 companies.

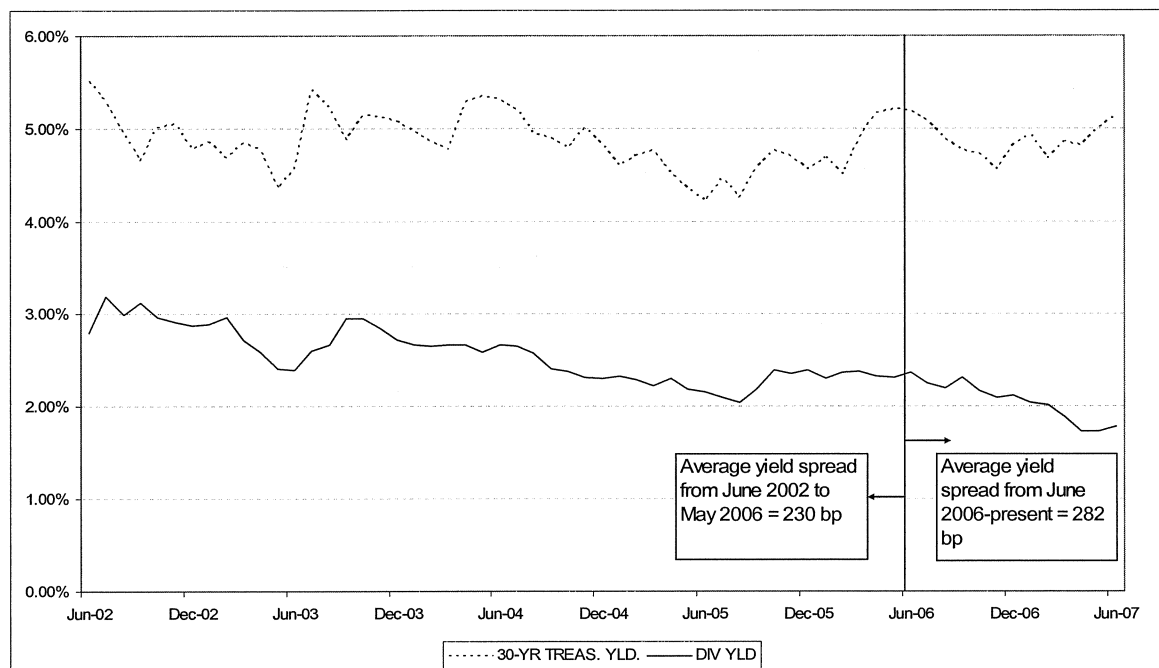
15 **Q. Have you performed any analyses to assess the current level of natural gas**
16 **LDC stock valuations?**

17 A. Yes, I analyzed three widely-accepted measures of utility stock price valuation: (1) the
18 difference between the yield on long-term Treasury bonds and utility dividend yields
19 (often referred to as the "yield spread"), (2) recent utility Price/Earnings ratios
20 relative to the long-term average; and (3) recent utility Market/Book ratios relative to
21 the long-term average. I discuss each of these valuation measures in turn, below.

¹³ Earlier this year Southwest Gas Storage determined that the working storage capacity at the North Hopeton storage field would not support the service obligations for firm storage service under Rate Schedule FSS.

(1) The Widening Yield Spread There is little question that utility stock prices and dividend yields are strongly related to interest rates. From June 2002 through May 2006, the yield spread between the average dividend yield (for the three LDCs used by the Commission in *Kern River*, i.e., National Fuel Gas, Questar, and Equitable Resources) and the 30-year Treasury rate was approximately 230 basis points. As shown on Chart 1 (below), however, for the period from June 2006 through June 2007, the average yield spread has increased to 282 basis points.

Chart 1: Historical Yield Spreads – LDCs



As Chart 1 also indicates, the widening yield spread has accelerated since the beginning of 2007. The data in Chart 1 therefore, indicate that over the past year, yield spreads were wider, and dividend yields were lower, than the long-term

1 relationship would suggest. That divergence is consistent with the notion that utility
2 stocks are currently “expensive” relative to interest rates.

3 The widening yield spread also has been noted by other industry analysts in their
4 assessment of current utility stock valuations. Calyon Securities, for example,
5 pointed out that between March and May 2007, the yield spread between the Dow
6 Jones Utility Index (the “DJUI”) and the ten-year Treasury Bonds increased by 50
7 basis points.¹⁴ While the DJUI is a relatively broad index of utility companies,
8 Calyon’s conclusion that dividend yields are unusually low relative to historical
9 standards supports the position that the current average dividend yield for the three
10 LDC’s does not represent long-term market conditions.

11 (2) The Price/Earnings Ratio Consistent with the widening of the yield spread, the
12 LDC group average Price/Earnings (“P/E”) ratio has increased significantly as a
13 percentage of the overall market (as measured by the S&P 500 Index). That is, over
14 the last 10 years (since June 1997), the LDC group average P/E ratio has been
15 approximately 70 percent of the S&P 500 P/E ratio. As of the end of the first
16 quarter of 2007 (3/31/07), the proxy group average P/E was approximately 141
17 percent of the S&P 500 P/E, indicating that utility stock earnings multiples are very
18 high relative to their historical norms. As shown on Chart 2 (below), the increase in
19 relative valuation multiples has accelerated significantly over the past several months.
20 In fact, since December 2006, the 180-day average LDC group P/E ratio has
21 increased from 19.55 to 22.70 (an increase of approximately 16.1 percent) while the

¹⁴ Calyon Securities, *Utility Valuation: Yields and Relative P/E’s Indicate It’s Time for a Pause*, May 29, 2007.

180-day average S&P 500 P/E ratio actually decreased from 17.68 to 17.41 (a decrease of 1.5 percent).

Chart 2: LDC P/E Relative to Market P/E



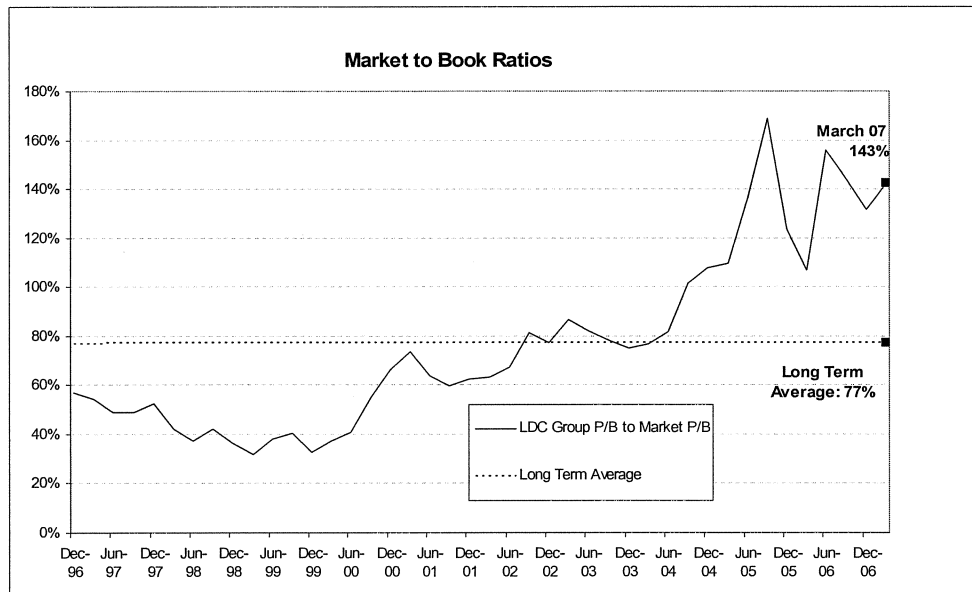
Here again, Calyon Securities arrived at a similar conclusion regarding relative P/E ratios, finding that the DJUI P/E as a percentage of the S&P 500 P/E ratio has increased from its long-term average of approximately 75 percent to 110 percent. In fact, Calyon noted that the current relative P/E (of 110 percent) is “the highest relative P/E in our study period and likely one of the highest in history.”¹⁵

(3) The Market/Book Ratio As with the widening of the yield spread and the increase in P/E relative to the market, market valuations for the proxy group companies, in terms of market/book ratios (“M/B”) recently have significantly deviated from long-term levels. As shown in Chart 3 (below), over the last 10 years (since June 1997),

¹⁵ Id.

the LDC group average M/B ratio has been approximately 77 percent of the S&P 500 M/B ratio. As of the end of the first quarter of 2007 (3/31/07), the LDC group average M/B was approximately 143 percent of the S&P 500 M/B, indicating again that utility multiples are very high relative to their historical norms.

Chart 3: LDC Market/Book Relative to Market Market/Book



Q. Are these valuation levels being driven by factors other than company and market fundamentals?

A. Yes, I believe so. In my view, the recent increase in valuations cannot be explained entirely by recently low interest rates or improving company fundamentals; investors' speculation relative to merger prospects have had a significant effect on utility stock valuations. Since the effective repeal of the Public Utilities Holding Company Act ("PUHCA") in February 2006, there have been a number of mergers announced in the utility segment. Moreover, the recent entrance of private equity firms has

1 introduced a substantial source of acquisition funds into the sector. Interestingly,
2 private equity investors have participated across the spectrum of utility M&A
3 transactions from the relatively small proposed acquisition of SEMCO Energy
4 (market capitalization of \$275 million) by Cap Rock Holding Corporation to the \$45
5 billion acquisition of TXU Corporation by a consortium led by Kohlberg, Kravis,
6 Roberts and Company, and the Texas Pacific Group. It is unclear, however, whether
7 the recent level of merger activity will continue. As AG Edwards recently pointed
8 out,

9 ...it has been 12 months since a new acquisition of gas utility assets
10 has been announced. High natural gas prices may be putting a
11 damper on new announcements. We continue to believe an
12 occasional announcement or two can be expected each year, but that
13 a wave of gas utility takeovers is unlikely.¹⁶
14

15 It appears, therefore, that the current level of utility valuations cannot be sustained
16 by market fundamentals and that the speculative effect of increased merger activity
17 by both utility operating companies and private equity firms likewise may not be
18 sustainable over the long term.

19 **Q. What are the implications of these findings for the determination of**
20 **Southwest Gas Storage's ROE?**

21 A. The analyses discussed above indicate that the LDC proxy group stock prices
22 currently are "expensive" relative to historical valuations and the market in general.
23 As a result, it is likely that the DCF results for the three LDCs cited in *Kern River*
24 significantly understate long-term expected returns. As discussed in greater detail

¹⁶ AG Edwards, Weekly Utility Summary, June 1, 2007.

1 later in my testimony, the effect of these market conditions is to produce DCF
2 results for LDC companies that are significantly below the results of other ROE
3 estimation methodologies. Under such market conditions it is appropriate to
4 question the relevance of the LDC companies as a proxy for Southwest Gas Storage.
5 If, however, the Commission were to continue to use the LDCs in its determination
6 of the Company's cost of equity, it would be appropriate to also consider the results
7 of alternative approaches.

8 **Q. What effect do these factors have on the determination of an appropriate ROE**
9 **for Southwest Gas Storage?**

10 A. As I have discussed previously, Southwest Gas Storage faces greater overall
11 operating risk than other interstate natural gas gathering and transportation
12 companies. Therefore, based on a proxy group of interstate pipeline entities, it
13 would be inappropriate to place the Company's ROE at the median result.
14 Furthermore, as the Commission pointed out in *Kern River*, there is no dispute that
15 pipeline companies are more risky than LDCs. As discussed above, however,
16 current LDC valuations would produce biased DCF results. As such, to the extent
17 that a proxy group that includes LDCs is used in this analysis, consistent with the
18 Commission's decision in *Kern River*, the ROE should be set well above the median
19 DCF result.

V. PROXY GROUP COMPANIES

Q. Why is it necessary to use a proxy group in the determination of an equity return?

A. The use of proxy groups is a widely employed analytical method to assist in estimating the cost of equity for a particular company. As discussed in more detail later in my testimony, the methods most commonly used by financial analysts to estimate the cost of equity are based on company-specific market data and projections. In the case of Southwest Gas Storage, which is a wholly owned subsidiary of SUG, the Company has no publicly traded common stock. As such, it is necessary to develop a group of publicly traded entities that are comparable to the Company in certain fundamental respects. Since it is possible that market data for a single company may reflect the effects of unusual or transitory events, the primary benefit of using a group of comparable companies is that it serves to attenuate the effects of anomalous events that may be associated with any one company. Additionally, proxy groups include a range of characteristics for companies deemed to be comparable to Southwest Gas Storage, and thus provide a benchmark to gauge the reasonableness of ROE estimate results.

Q. How did you select the companies included in your proxy group?

A. I began with the six company group used by the Administrative Law Judge in her initial decision in *Kern River*. These six companies are derived from the same group, adjusted for divestitures and mergers, approved by the Commission in *Williston Basin*, and today represent those corporate entities with the most significant natural gas pipeline holdings. That group consists of El Paso Corporation; Equitable Resources,

1 Inc.; Kinder Morgan, Inc.; National Fuel Gas Company; Questar Corporation; and
2 Williams Companies.

3 **Q. Have you adopted the six company group in its entirety as your proxy group?**

4 A. No, I have not. While all of those companies meet certain screening criteria, there
5 are varying degrees to which their financial performance relies on regulated, as
6 opposed to non-regulated operations. Moreover, several of those companies derive
7 only a small portion of their financial results from FERC-regulated natural gas
8 transmission. As discussed in more detail below, the effect of that criterion is to
9 substantially limit the number of corporate natural gas pipeline companies that
10 reasonably can be considered comparable to Southwest Gas Storage.

11 **Q. On what basis do you claim that certain of the six companies previously listed**
12 **as successors to the Williston Basin proxy group, fail to meet your screening**
13 **criteria?**

14 A. Equitable Resources and Questar fail to meet my requirement that natural gas
15 transmission represents a significant portion of the combined business segments.
16 Further, Equitable Resources failed to meet the criterion that a substantial portion of
17 its economic value is derived from interstate pipeline or storage operations¹⁷. These
18 companies have been rejected by the Commission in the past due to the fact that
19 they are substantially local distribution companies with a significantly different risk
20 profiles than that of Southwest Gas Storage.¹⁸ El Paso's financial condition requires
21 that it be excluded from my proxy group due to the reduction of its dividend and its

¹⁷ Furthermore, Equitable is currently engaged in the acquisition of Dominion Peoples and Dominion Hope, a transaction that is under investigation by the Federal Trade Commission.

¹⁸ *Williston Basin Interstate Pipeline Co.*, 87 FERC ¶61,264 at 62,007 (1999).

continued low credit rating. Finally, in May 2006, Kinder Morgan announced its intention to be taken private; on May 24, 2007 the transaction received approval from the California Public Utilities Commission (which was the last regulatory approval required to close the transaction) and on May 30, 2007 the transaction closed.

Q. Please describe the basis on which you determined whether the candidate companies were substantively engaged in natural gas transmission.

A. As summarized on Table 1 (below), as of December, 2006, the percentage that pipeline operations contributed to revenues, operating income and utility assets varied significantly among the six corporate natural gas pipeline companies:

Table 1: Business Segment Information¹⁹

Company	% Revenue from Pipeline Operations	% Operating Income from Pipeline Operations	% Assets from Pipeline Operations	Overall Weighting
El Paso Corporation	63%	3%	55%	59%
Equitable Resources	5%	7%	0%	6%
Kinder Morgan, Inc.	61%	53%	56%	64%
National Fuel Gas	10%	37%	21%	23%
Questar Corp.	6%	13%	0%	10%
Williams Companies	11%	37%	26%	25%

For the purposes of my ROE recommendation, I have considered those companies with an overall weighting for interstate natural gas pipeline operations of greater than 25% to be significantly engaged in interstate natural gas transportation. In my view, this approach is somewhat more inclusive than the approach taken in *Williston* wherein the Commission stated that it determined whether a company's pipeline

¹⁹ Source: SEC Forms 10-K and 10-Q. The percentages in the table represent the average of 2006, 2005 and 2004. Refer to Exhibit No. SGS-70.

1 operations constituted a high proportion of its business based on whether on average
2 over the most recent three year period, approximately 50 percent or more of “total
3 dollars” was produced in at least one of two areas, including operating income and
4 total assets.²⁰

5 As indicated in Table 1 (above), my analysis of Equitable Resources indicates that
6 only 6 percent of its combined operations were derived from natural gas pipeline
7 operations, whereas 24 percent of its operations are related to its LDC activities and
8 52 percent relate to natural gas supply. Questar’s natural gas pipeline operations
9 comprise only 10 percent of its business, while its gas distribution operations total 24
10 percent, and its exploration and production operations contribute 66 percent of its
11 total. National Fuel’s natural gas pipeline operations represent approximately 23
12 percent of its operations, while its LDC operations make up 42 percent, and the bulk
13 of the remainder is attributable to exploration and production. In the case of
14 Questar and Equitable, there is little question that interstate pipeline and storage
15 services constitute too small a percentage of consolidated operations to be
16 considered comparable to Southwest Gas Storage.

17 **Q. Why have you excluded National Fuel from your proxy group?**

18 A. First, National Fuel derived approximately 23 percent of its consolidated operations
19 from interstate gas pipelines and storage services. Since that level of operations is
20 below my 25 percent threshold, in my view, National Fuel does not have sufficient
21 interstate pipeline and storage operations to be considered comparable to Southwest
22 Gas Storage.

²⁰ Kern River Gas Transmission Company, 117 FERC ¶ 61,077, fn 225.

1 It also is important to note that the DCF result for National Fuel Gas is considerably
2 below any reasonable estimate of required equity returns for natural gas utilities,
3 much less interstate pipeline and storage companies. As the Commission pointed
4 out, investors cannot be expected to invest in common equity if debt “yields
5 essentially the same return.”²¹ At that time, the DCF model produced ROE
6 estimates for El Paso and Williams that were approximately 110 basis points above
7 the Moody’s utility index bond yield. As shown on Table 2 (below), the current
8 spread (*i.e.* the implied equity risk premium) between the DCF result for National
9 Fuel and the six-month average yield on the Moody’s Baa utility bond index is
10 approximately 186 basis points. Even that risk premium, however is inadequate to
11 attract new investment. The spread between Commission-authorized natural gas
12 pipeline returns and the Moody’s Baa utility bond yield demonstrates that the
13 required risk premium is far greater than 190 basis points. As shown in Table 2
14 (below), the spread between the Moody’s Baa utility bond yield and the allowed
15 return in *Kern River* was 495 basis points. Furthermore, the average spread between
16 the Moody’s Baa utility bond yield index and the average Commission-authorized
17 pipeline returns from 2000 through the first quarter of 2007 is 425 basis points. The
18 190 basis point risk premium implied by the National Fuel Gas DCF result,
19 therefore, is unrealistically low.

²¹ *Southern California Edison Company*, 92 FERC ¶ 61,070 at 61,266 (2002). Referred to herein as “SoCal”.

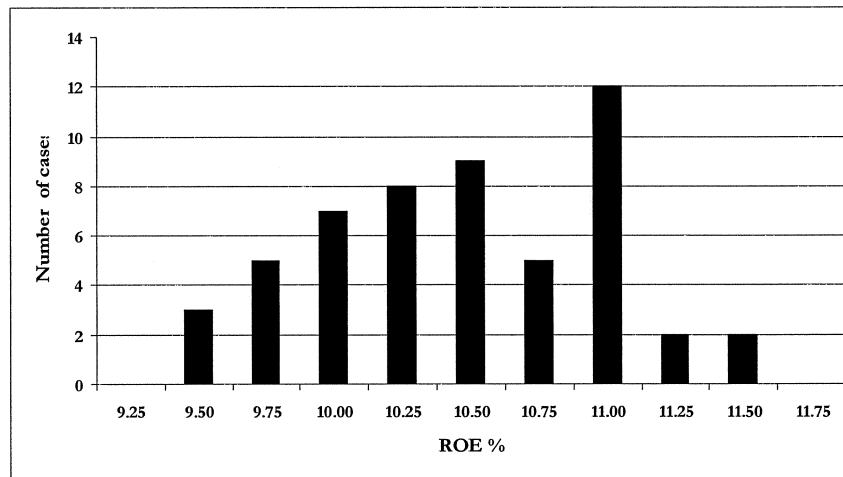
Table 2: Equity Risk Premia

	National Fuel Gas	Kern River	Authorized Pipeline Returns
DCF Result	8.05%	11.20%	11.68%
Moody's Baa Utility Bond Yield	6.15%	6.25%	7.43%
Equity Risk Premium	1.90%	4.95%	4.25%

Q. Is there another benchmark that can be used to assess the reasonableness of the DCF results for National Fuel?

A. Yes. As the Commission pointed out in *SoCal*, there is no dispute that LDCs are less risky than interstate pipeline companies. As shown on Chart 4 (below) since 2004 there has not been a single natural gas utility ROE award that has been below 9.45 percent. In addition, during that same time period the average spread between authorized gas LDC ROEs and the concurrent yield on the Moody's Baa utility index (i.e., the equity risk premium) was over 400 basis points. National Fuel's 8.05 percent DCF result, therefore is clearly well below the return that would be expected for the comparatively low risk LDC group, much less than would be expected for interstate pipeline and storage companies. Consequently, it would be inappropriate to include National Fuel in the Southwest Gas Storage proxy group.

Chart 4: LDCs Allowed Return on Equity



Q. Why have you excluded El Paso from your proxy group when it has the highest percentage of natural gas pipeline operations of all the companies?

A. El Paso, although it is owner of a large pipeline network, continues to suffer from a weakened financial and credit profile. El Paso reduced its dividend in 2003 and, as a result, has the second lowest dividend yield of any company being considered for potential inclusion in the proxy group. In addition, while the rating agencies have provided mixed signals on the outlook for El Paso, they have noted significant concerns with the company's balance sheet and its exploration and production business unit. FitchRatings ("Fitch") recently recognized an improvement in the company's credit profile; however, Fitch remains concerned by the "significant leverage that remains on the balance sheet and lingering issues with the upstream operations."²² Fitch further noted that "[w]hile the balance sheet improvement at El Paso is significant, including a material reduction in external debt at the parent

²² FitchRatings, Leveraged Finance Weekly, March 9, 2007.

1 company level, consolidated and parent company debt will remain sizeable at year-
2 end 2007.”²³ Finally, Fitch stated that upstream operating results would have to
3 improve and credit measures would need to strengthen before it would consider
4 taking a positive rating action. Fitch currently assigns El Paso a BB+ rating with a
5 “stable” outlook.

6 Standard & Poor’s (“S&P”) assigns El Paso a BB rating with a “positive” outlook,
7 citing as weaknesses “aggressive debt leverage, weak cash flow credit protection
8 measures and underperforming exploration and production operations”²⁴. S&P
9 clarifies that its positive outlook reflects “the potential for the E&P segment to
10 produce the cash flow necessary for improved credit metrics in the next 18 to 24
11 months.”²⁵ S&P noted, however, that the E&P business unit has repeatedly failed to
12 meet its targets in recent years. Furthermore, S&P noted that “[f]ailure to meet
13 upstream targets or a deterioration in liquidity could dampen upward ratings
14 prospects”.²⁶

15 Finally, while Moody’s assigns El Paso a positive outlook and a credit rating of Ba3,
16 Moody’s also states that the company’s credit rating hinges on the returns of the
17 E&P business segment. The E&P business segment, which represents
18 approximately one-third of the company’s EBIT is identified by Moody’s as the
19 company’s “predominant business risk”. Such a company cannot be expected to
20 share the same investment expectations as those for a financially stable company
21 such as Southwest Gas Storage.

²³ Id.

²⁴ Standard & Poor’s Ratings Direct, ElPaso Corp, June 6, 2007, p. 1.

²⁵ Ibid, p. 3.

²⁶ Ibid.

1 Although the rating agencies describe El Paso's financial condition as having
2 improved substantially, it also is evident that El Paso continues to face balance sheet
3 and other financial and operating risks. As discussed below, it is equally clear that
4 the company's DCF results do not adequately reflect those risks relative to the other
5 comparison companies; in fact El Paso, which arguably is the highest risk of the
6 potential proxy companies, has the second lowest DCF result (see Exhibit No. SGS-
7 66).

8 **Q. Why did you not consider Southwest Gas Storage's parent company, Southern**
9 **Union Company, for inclusion in the proxy group?**

10 A. I have not considered Southern Union Gas for inclusion in the proxy group due to
11 the limited history of its cash dividend payment, as the company has only been
12 paying dividends for one year. In my view, the company's limited dividend history
13 disqualifies SUG from consideration in the group. Moreover, it generally is my
14 practice not to consider the subject company or its parent for inclusion in the proxy
15 group.

16 **Q. What companies remain from the six that you considered for inclusion in the**
17 **proxy group?**

18 A. Only the Williams Companies remain and, therefore, there is no viable proxy group
19 using only publicly-traded pipeline corporations. Moreover, Williams' credit rating
20 remains below investment grade. Typically, to obtain a group of companies with
21 comparable business risks, I would apply a screen to my proxy group candidates to
22 verify that all companies were of investment grade or better. If such a credit rating
23 requirement for all proxy group companies' were applied in this case, however, even

1 Williams would have been excluded, leaving no corporate pipeline proxy companies.
2 As opposed to El Paso, whose DCF results are implausibly close to the Moody's
3 utility index bond yield and considerably below any recently authorized gas LDC
4 equity return, William's DCF result, while somewhat low relative to recent LDC
5 authorized returns and pipeline company equity risk premia, is demonstrably above
6 the Company's current debt cost rate (see Exhibit No. SGS-67). Moreover, the
7 rating agencies tend to be more positive about the financial and operating
8 improvements made by Williams than El Paso. Fitch has assigned Williams a
9 "positive" outlook suggesting a stronger credit profile than El Paso. S&P assigns
10 Williams a rating of BB+ with a "stable" outlook, indicating that this outlook will be
11 upgraded to positive if Williams "continues to strengthen its credit metrics and
12 exercises greater capital discipline."²⁷ Furthermore, S&P notes that:

13 Williams has significantly improved its financial metrics and
14 operating performance. Williams has employed capital discipline as it
15 has rebalanced its portfolio and reduced debt leverage, positioning
16 the firm to garner greater expected cash flow. In addition, the
17 company has taken steps to fortify its liquidity and decrease its
18 exposure to long-dated tolling contracts.²⁸
19

20 Finally, Moody's has recently placed Williams under review for a possible upgrade.
21 The upgrade is being attributed to Williams' announcement that it intends to sell
22 substantially all of its merchant power generation operations, which is expected to
23 improve leverage and lower the volatility of cash flow and earnings.²⁹ Consequently,
24 it would not be unreasonable to include Williams in the proxy group. Even if one

²⁷ Standard & Poors, RatingsDirect, The Williams Cos. Inc, March 30, 2007, p. 4.

²⁸ Ibid, p. 1.

²⁹ Moody's Investors Service, Global Credit Research Rating Action, The Williams Companies, May 21, 2007.

1 were to include Williams, given the lack of fundamental comparability issues
2 associated with LDCs (discussed earlier) and the fact that only one corporate pipeline
3 possibly could be considered (*i.e.*, Williams), it is necessary to expand the universe of
4 potential comparison companies to include publicly traded interstate gas pipelines
5 structured on MLPs.

6 **Q. Please discuss the process by which you selected the companies included in**
7 **your proxy group.**

8 A. To ensure that my proxy group meets the comparability standard set forth in *Hope*
9 and *Bluefield*, I began by considering all of the companies that Value Line classifies as
10 the Diversified Natural Gas industry group. This industry group includes the
11 majority of the publicly-traded corporations and MLPs that have significant interests
12 in interstate natural gas transportation. As I have discussed, the publicly traded
13 corporations did not meet the criteria for inclusion in the proxy group. I then
14 considered MLPs with significant natural gas pipeline operations that were not
15 covered by Value Line. From this population, I applied the following criteria (see
16 also Exhibit No. SGS-68):

- 17 1) All of the companies have publicly-traded common stock or units;
- 18 2) All of the companies have significant involvement in natural gas transmission
19 and own 100 percent of at least one FERC-regulated natural gas pipeline;
- 20 3) All of the companies derive a substantial portion of their revenues and income
21 from natural gas transmission;
- 22 4) All of the companies are currently paying cash dividends or distributions;
- 23 5) All of the companies are in sound financial condition with no pending negative
24 ratings actions that would significantly impact investors' perception of risk; and

1 6) None of the companies are engaged in significant transactions involving mergers
2 or acquisitions.

3
4 The first two criteria are consistent with the Commission's Order in *EPGT Texas*
5 *Gas Pipeline L.P.*, 99 FERC ¶61,295 (2002), wherein the Commission commented on
6 screening criteria for proxy group companies in natural gas proceedings. To that
7 point, the Commission stated that "The companies should be publicly-traded,
8 engaged largely in natural gas transmission, and own natural gas pipelines regulated
9 by the Commission."³⁰

10 In order to determine the extent to which the candidate companies are engaged in
11 pipeline operations, I developed a list of interstate pipelines owned by each of the
12 companies evaluated for potential inclusion in the proxy group (see Exhibit No.
13 SGS-69). For each of those companies, I gathered revenue, operating income, and
14 asset data by business segment for the years ended 2006, 2005 and 2004. Based on
15 that data, I calculated the percentage of revenues, operating income and assets
16 associated with natural gas transmission; an analysis that is critical to the selection of
17 a reasonable proxy group in identifying peer companies with risks comparable to
18 those of Southwest Gas Storage. (See Exhibit No. SGS-70).

19 **Q. Did you use the same proxy group screening criteria for the MLPs and the**
20 **corporate companies reviewed above?**

21 **A.** Yes, I have reviewed the publicly-traded corporations and the MLPs engaged in
22 natural gas pipeline operations according to the thresholds discussed earlier.

³⁰ 99 FERC at 62,250.

1 **Q. What is the final composition of your proxy group?**

2 A. My proxy group is comprised of the following seven companies:

- 3 • Williams Companies
- 4 • Boardwalk Pipeline Partners, L.P.
- 5 • Enbridge Energy Partners, L.P.
- 6 • Enterprise Products Partners, L.P.
- 7 • Kinder Morgan Energy Partners, L.P.
- 8 • MarkWest Partners, L.P.
- 9 • OneOK Partners, L.P.

10 Exhibit No. SGS-69) provides a list of pipelines owned by each of the MLPs
11 included in my proxy group.

12 **Q. Please explain further why you consider it appropriate to include Master**
13 **Limited Partnerships in your proxy group.**

14 A. As a practical matter, since only one pipeline company can reasonably be considered
15 a candidate for the proxy group, it is necessary to consider other proxy entities,
16 including LDCs and MLPs. As noted earlier, however, the business segment profile
17 and DCF results for the LDCs disqualify those companies from inclusion in the
18 proxy group. Moreover, since the investment in pipeline assets is beginning to be
19 dominated by MLPs, it is important to recognize their legitimacy as proxy companies
20 in gas pipeline proceedings. To that point, a recent white paper prepared for the
21 Interstate Natural Gas Association of America ("INGAA") recognizes the
22 importance of MLPs in developing proxy groups:

1 Currently, the fundamental issue in selecting a proxy group in a
2 natural gas pipeline rate case is whether or not to include
3 representatives of the many pipeline companies that are organized as
4 MLPs. The basic premise for creating the proxy-group approach in
5 the first place was that, because gas pipeline companies were not
6 publicly-traded, a group of similar publicly traded companies was
7 needed in order to establish a proxy for investor expectations
8 regarding natural gas pipelines. Now as MLPs have grown in
9 number, scope and importance, they comprise a very representative
10 group of true, publicly-traded pipeline companies to which the
11 Commission can turn for market guidance.
12

13 The Commission has relied on MLPs as proxy companies in oil pipeline cases. Also,
14 the Commission considered a proxy group including MLPs to be “reasonable” in
15 *Natural Gas Pipeline Company of America, and Panther Interstate Pipeline Energy, LLC*, 105
16 FERC ¶61,383 (2003), for purposes of imputing a capital structure on Panther. That
17 proxy group included Equitable Resources, Kinder Morgan, KM Energy, National
18 Fuel, ONEOK, Inc., Questar, and TEPPCO. Moreover, as noted earlier the
19 Commission stated in *Kern River* and *HIOS*, that it was “not making a generic finding
20 that MLPs cannot, in future cases, be considered for inclusion in the proxy group if a
21 proper evidentiary showing is made”.³¹

22 **Q. What was the Commission’s concern with respect to the inclusion of MLPs in**
23 **the proxy group in *HIOS* and *Kern River*?**

24 **A.** The Commission’s concern centered on whether the distribution payment to the unit
25 holders included a return of a portion of the partner’s original investment, and if so,
26 whether it would effectively distort the dividend yield component of the DCF
27 model. In *Kern River*, the Commission noted that while it did not intend to

³¹ *Kern River*, Docket No. RP04-274-000, Opinion No. 486, October 19, 2006, p. 63.

1 “foreclose” the issue of whether or not an MLP could be included in a proxy group,
2 non-MLP companies must demonstrate that the payment of distribution is
3 consistent with the expected growth rates used in the DCF analysis. Thus, the
4 Commission stated that it would not consider including an MLP in the proxy group,
5 unless the record demonstrates that the distribution used as the “dividend” includes
6 only a payment of earnings and not a return of investment.³² INGAA recently
7 addressed the Commission’s concern, noting that:

8 This white paper concludes that the Commission’s concern is
9 misplaced. An examination of a five-year history of actual returns to
10 equity investors from the gas-pipeline MLPs revealed that a short-
11 term DCF analysis for the same period would have been a very
12 accurate predictor of actual returns. Measuring investor expectations
13 by applying the DCF formula to a group that includes MLPs would
14 appear to be as valid as any application of the formula to stock-
15 owned companies.³³
16

17 **Q. Do you agree with INGAA regarding the inclusion of MLPs in the proxy**
18 **group?**

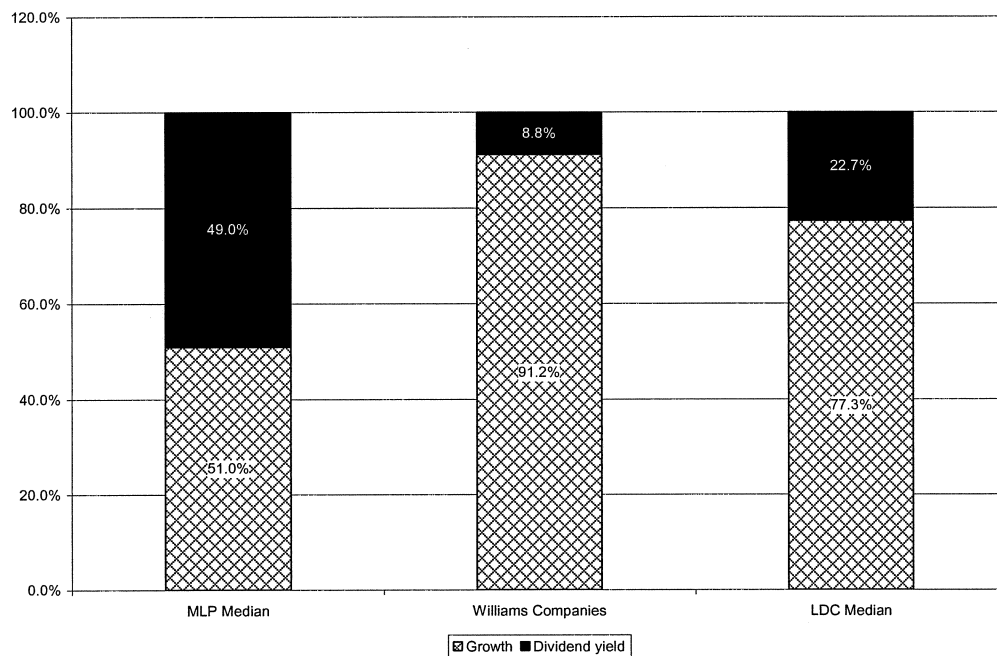
19 **A.** Yes. I do. Investors value assets based upon the expected future cash flows they
20 will generate and do not differentiate their valuations based upon whether the source
21 of that cash is a stock dividend or a partnership unit distribution. A 13.50 percent
22 investment return on an MLP unit is no different than a 13.50 percent investment
23 return on a share of stock, of equivalent risk, regardless of whether it is classified as a
24 dividend or distribution. Generally, the primary difference between the two
25 investments is the timing of cash flows, i.e., MLPs will generate greater cash flows

³² *HIOS, LLC*, 110 FERC ¶ 61,043.

³³ INGAA, “*Allowed Returns on Equity in the Interstate Gas Pipeline Industry Issues and Options Regarding the FERC DCF Approach*”, dated August 24, 2006, at 5.

during the holding period, with less potential for capital appreciation (generally, recognized as the growth component of the DCF model). Stocks, on the other hand, pay a lower dividend but have a greater potential for capital appreciation. Chart 5 (below) demonstrates that in fact, the ROE estimates for MLPs, corporate pipelines (i.e., Williams) and the LDCs have radically different compositions; the portion of the ROE relating to growth is significantly lower for the MLPs, while the dividend component is significantly greater.

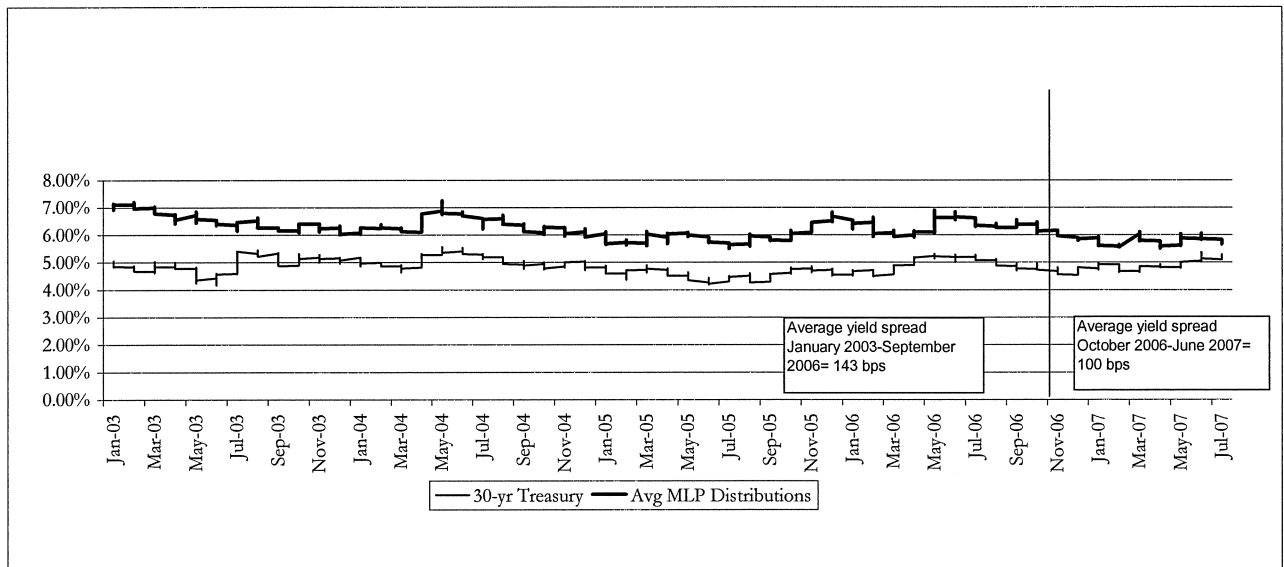
Chart 5: DCF Components



- Q. Earlier you discussed the spread between yields on utility stocks and Treasury yields. Have you performed a similar analysis for the MLPs?**
- A. Yes. I analyzed the yield spread between MLPs and long-term Treasury Bonds. As shown in Chart 6 (below), the yield spread between the 30-year Treasury and MLP**

distributions remained fairly constant from the beginning of 2003 through the third quarter of 2006. Since that time the yield spread has declined steadily from 143 basis points to 100 basis points. As with utility stocks, it appears that MLP distribution yields are somewhat lower than otherwise would be expected based on long-term market relationships.

Chart 6: Historical Yield Spreads



Q. Do the relatively high distribution yields characteristic of an MLP cause the DCF analysis to overstate the ROE recommendation for a corporate pipeline company?

A. No. Investors understand that in general, there is a trade-off between distribution and expected growth. It is true that MLPs generally pay out a greater share of cash in distributions than a corporation would pay in dividends, as required by the tax

1 code. However, it follows as a consequence of the high payout that MLPs have less
2 cash available for reinvestment, and, as a result, their growth expectations are often
3 lower than the growth expectations for corporations.

4 **Q. Has the DCF model historically provided an accurate measure of investors'**
5 **expectations for MLPs?**

6 A. Yes, it appears that the two-stage DCF model adequately weighs the income
7 prospects of an investment with its growth prospects and in general does provide an
8 accurate reflection of future returns. The performance of the DCF model in
9 evaluating the returns of MLPs were examined in the INGAA paper by
10 "backcasting", or comparing the actual return to investors for a recent past period
11 with the return that would have been predicted by a short-term DCF study for the
12 same period. That study indicated that a short-term DCF approach would have
13 predicted a return of 17.22 percent, compared to the 18.48 percent return that was
14 actually realized by the investors. This study provides reasonable evidence that, in
15 fact, the DCF formula, applied directly to the MLPs provides an accurate (if not
16 conservative) representation of investors' expectations.³⁴

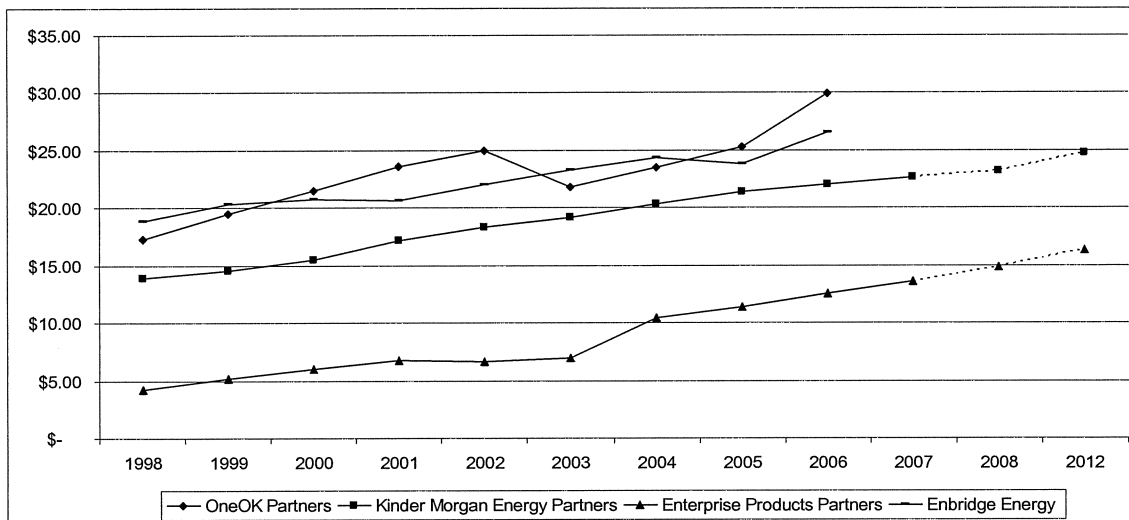
17 **Q. Have you performed any analyses to determine whether or not the MLPs**
18 **actually reflect a diminution of capital from distributions?**

19 A. Yes, I have performed an analysis of the natural gas pipeline MLPs covered by Value
20 Line to determine whether there is any diminution of capital resulting from equity
21 distributions by reviewing the historical (and projected) book capital per unit. My
22 analysis is premised on the construct that if MLP distributions were in fact a return

³⁴ INGAA, *Allowed Returns on Equity in the Interstate Gas Pipeline Industry Issues and Options Regarding the FERC DCF Approach*, dated August 24, 2006, at 20.

of capital, the book capital per unit would steadily decline over time. Additionally, forward projections of book value per unit growth would be zero or negative.

Chart 7: Partnership Capital per Unit (Adjusted for Market to Book Effect on New Issuances)³⁵



As shown in Chart 7 (above) and in Exhibit No. SGS-71, my results affirm that there is no diminution of capital resulting from equity distributions, in nominal or real terms, and that book value per unit, distributions per unit, and earnings per unit grow steadily over the analyzed period from 1998 to 2012.

To determine whether analysts other than Value Line expect distributions to be made out of operating cash flows, I examined the projected distributable cash flow and distributions for those MLPs in my proxy group that are covered by RBC Capital Markets (“RBC”). As part of its coverage, RBC provides detailed projections of distributable cash flows and distributions per unit. As shown in Exhibit No. SGS-

³⁵ Source: Valueline growth estimates. Valueline did not report growth estimates for OneOk Partners and Enbridge Energy Partners.

72, the “distribution coverage” (i.e., the ratio of distributable cash flow to distributions) never falls below 1.0, indicating that distributions are expected to be paid entirely out of distributable cash flows³⁶.

Q. Do the RBC reports provide any other insights?

A. Yes. As part of its cash flow projections, RBC projects the distributions expected to be paid out to the General Partner. As noted by Wachovia Capital Markets, LLC, the yield should take into consideration payments made to the General Partner.³⁷ Based on the RBC projections, that adjustment would increase the yield by approximately 170 to 205 basis points.

Q. Have you performed any analyses in response to the Commission’s concern that MLP growth rates may be “distorted” as a result of external financing?

A. Yes. The Commission’s concern appears to be premised on the proposition that over the long term, corporate growth is largely financed by internally generated funds. Internally generated funds, then, are a function of the return on equity and the percentage of earnings retained (i.e., the percentage of earnings not paid out in dividends). To the extent that MLPs distribute a large portion of their earnings or cash flow, there is less cash available for reinvestment; their growth, therefore, must be funded from external sources. At issue, then, is whether the corporate companies’ expected growth rates also are significantly dependent on external financing. To the extent that is the case, it is unclear whether the MLP growth rates are “distorted” by virtue of their dependence on external funds.

³⁶ Cash flows are based on maintenance capital expenditures, and include payments to the general partner. It should be noted that total capital expenditures are likely to include items in addition to maintenance capital expenditures.

³⁷ Wachovia Capital Markets, LLC, Master Limited Partnerships: Primer 2nd Edition, August 23, 2005, p.18.

1 To determine whether the corporate companies' growth rates are materially affected
2 by expected external financing, I calculated the internal growth rate (defined as the
3 product of the retention ratio and the expected return on equity) for each of
4 Questar, Equitable, National Fuel Gas and Williams. As shown on Exhibit No.
5 SGS-73, the average internal growth rate for those four companies is 5.24 percent.
6 As also shown on that Exhibit, the average I/B/E/S growth rate is 8.75 percent.
7 The average difference of 3.51 percent, therefore, reflects the extent to which
8 expected growth is dependent on external financing. Thus for the four corporate
9 entities, external funding represents approximately 40 percent of expected growth.
10 While that is certainly lower than the extent to which MLPs are dependent on
11 external financing, it nonetheless is a significant portion³⁸. Consequently, it is my
12 view that external funding does not "distort" the MLP growth rates relative to the
13 corporate growth rates.

14 **Q. Please discuss the tax treatment of the MLPs for unit holders.**

15 A. MLPs combine the benefits of a partnership with the liquidity of a publicly traded
16 stock. According to the IRS, an MLP is a partnership whose interests are traded on
17 an established securities market or are readily tradable on a secondary market (or its
18 substantial equivalent). Distribution holders are taxed directly at their marginal
19 income tax rate for their share of partnership net income, regardless of the amount
20 of the distribution that they have received. Generally, MLPs distribute the majority
21 of their free cash leaving little cash retained in the business. Because there generally

³⁸ As shown on Exhibit SGS-72, page 4 of 4, on a historical basis, total capital expenditures and dividends exceeded operating cash flows (on average) for the three LDCs, indicating that external financing has been required for growth.

1 is a significant difference between free cash flow and net income, due to the large
2 depreciation charge on pipeline assets, unit holders are afforded a significant tax
3 incentive by minimizing taxable income recognition during the holding period and
4 deferring payment on the majority of taxes until the ultimate sale of the partnership
5 units. To the extent that the cash distribution exceeds the unit holder's share of
6 marginal income (which generally is the case), the unit holder's tax basis in the
7 partnership will be reduced, which has the effect of deferring taxation on that
8 portion of the distribution until such time as the partnership unit is sold.

9 **Q. How does this compare to the tax treatment of publicly-traded corporate**
10 **entities?**

11 A. Generally, in the case of both MLPs and corporations, every dollar received by way
12 of distribution to the unit or shareholders is taxed over the holding period, from
13 purchase to sale. In the case of the corporation, its shareholders are taxed on its
14 dividends, and the basis of the original investment is never reduced, regardless of
15 whether the dividend exceeded earnings per share. At the time of sale, any capital
16 gain (or loss) will be determined by subtracting the original basis from the proceeds
17 of the sale. As discussed above, the MLP unit holder generally pays taxes on a
18 portion of its distribution, but the non-taxable portion of the distribution reduces the
19 basis, and leads to earlier recognition of income.

20 In Exhibit No. SGS-74, I have developed a simple example that illustrates that the
21 unit holder or shareholder is ultimately taxed on 100 percent of all distributions or
22 dividends and all capital gains, over the holding period, in both the corporate and
23 MLP scenarios. That example assumes that net income is \$5 per share, the payout

1 ratio is 100 percent, and distributions are \$20 per share. The example further
2 assumes that a \$100 investment in a share of stock or MLP unit was made at the end
3 of year 0, and the investment was sold at the end of year 4 for \$200. Capital gain
4 amounts are determined by subtracting the basis, at the end of year 4, from the
5 proceeds of the sale. Growth rates are assumed to be zero for purposes of
6 simplifying the example.

7 The example illustrates the tax deferral feature of the MLP, as the taxable gain in the
8 year of sale is greater than it would be upon the sale of a corporate stock, to the
9 extent that distributions exceeded partnership income. However, in the end, every
10 dollar received, whether in the form of distributions, dividends, or capital gains, is
11 taxable both to the MLP unitholder and corporate stockholder. It should be noted
12 that once the MLP basis is reduced to zero, 100 percent of all distributions are fully
13 taxable in the period they are received.

14 **Q. Are you aware that legislation recently has been introduced regarding the**
15 **taxation of publicly traded partnerships?**

16 A. Yes. On June 14, 2007, Senators Baucus and Grassley introduced legislation that
17 "...would tax as corporations all partnerships that directly or indirectly derive
18 income from investment advisor or asset management services."³⁹ On its face, the
19 bill appears expressly limited to partnerships that derive income or gains "...from
20 services provided by any person as an investment advisor, as defined in the
21 Investment Advisors Act of 1940, or as a person associated with an investment

³⁹ United States Senate Committee on Finance, News Release dated June 14, 2007, *Baucus-Grassley Bill Addresses Publicly Traded Partnerships*

1 advisor, as defined in that Act.”⁴⁰ The bill does not address the use of such
2 partnerships, as Congress envisioned, in fostering energy infrastructure investment.

3 **Q. How does the investment community regard MLPs in comparison to**
4 **corporations; in what ways do they differ in the eyes of the investor?**

5 A. Investors consider the two primary components of the return on their investments,
6 yield and growth. The decision to invest in MLPs, relative to other publicly traded
7 securities, is largely dependent on the investor’s preference with respect to
8 distributions, tax treatment, growth prospects, and risk. S&P discusses the features
9 of MLPs in the context of the greater market, acknowledging that there is a trade-off
10 between the receipt of large cash distributions and the resulting loss of financial
11 flexibility that is characteristic of MLPs:

12 The main attractive feature of MLPs for investors is that they avoid
13 double taxation by paying out nearly all free cash flow to unitholders.
14 In addition, general partners of MLPs can receive an increasingly
15 large interest in distributions as dividends are raised. However,
16 MLPs therefore also often have limited financial flexibility and must
17 rely on their ability to raise fresh debt or equity to fund new
18 investments.⁴¹
19

20 **Q. What are your conclusions with respect to the inclusion of MLPs in the proxy**
21 **group and whether MLP distributions constitute a return of capital for**
22 **purposes of developing an ROE estimate?**

23 A. It is appropriate to treat the distribution yield exactly the same as the dividend yield
24 for purposes of calculating the DCF ROE estimates. It is understood that MLPs
25 typically have higher distribution yields than corporations have dividend yields, but

⁴⁰ Congressional Record – Senate, S7744, June 14, 2007.

⁴¹ Standard and Poor’s, *Commentary Report, Key Rating Factors For U.S. Natural Gas Pipelines*, August 10, 2005, at 3.

1 this difference is offset in the growth rates of the two companies' structures. The
2 MLPs will assume a lower growth rate with less cash available to fund growth, where
3 as corporate pipeline companies would generally expect a higher growth rate in
4 conjunction with a lower dividend yield. As discussed earlier in my testimony,
5 however, for the MLPs included in my proxy group there is no indication that the
6 distribution yields are unduly biased by the source of distributable funds or that
7 external financing distorts the MLP growth rates relative to corporate growth rates
8 (See Exhibit No. SGS-75). My results therefore indicate that there is no
9 distinguishable difference between the returns required by investors for a publicly-
10 traded corporation versus a publicly-traded MLP (all else being equal).

11 **VI. DETERMINATION OF THE APPROPRIATE ROE**

12 **Q. Please describe the DCF approach.**

13 A. The DCF approach is based on the theory that an equity share's price represents the
14 present value of all future expected cash flows. In its simplest form, the DCF model
15 expresses the ROE as the sum of the expected dividend (or distribution) yield and
16 long-term growth rate. The DCF approach estimates a firm's ROE as the rate that
17 equates the discounted value of all future cash flows expected by investors with the
18 value of its common stock (or limited partnership units). In its most common form,
19 the DCF model is expressed as follows:

20
$$k = \frac{D(1+g)}{P} + g \quad [1]$$

21 where " k " equals the required return, " D " is the current dividend (or distribution),
22 " g " is the expected growth rate, and " P " represents the subject company's stock (or

1 unit) price⁴². As noted later in my testimony, consistent with Commission precedent,
2 the two-stage form of the DCF model used in my analysis is essentially similar to
3 Equation [1], but for the fact that the growth rate, g , is calculated as the weighted
4 average of a near-term and a long-term growth rate.

5 **Q. What assumptions are required for the DCF model?**

6 A. The DCF model requires the following assumptions: (i) a constant average growth
7 rate for earnings and dividends; (ii) a stable dividend payout ratio; (iii) a constant
8 price-to-earnings multiple; and (iv) a discount rate greater than the expected growth
9 rate. In light of those assumptions, it is not uncommon for analysts to apply
10 considered judgment or to make specific adjustments to model inputs or results in
11 arriving at an ROE recommendation.

12 **A. Dividend (or Distribution) Yield**

13 **Q. How did you determine the dividend yield?**

14 A. In keeping with Commission precedent, I have used the current annualized dividend
15 (or distribution) together with the average of the high and low stock prices for each
16 of the most recent six-months for each of the proxy group companies as of June 30,
17 2007.⁴³ My calculation of the average stock or unit prices for each proxy group
18 company is shown on Exhibit No. SGS-76. As shown in that Exhibit, I also
19 calculated the average stock price using the simple 180-day average price as of June
20 30, 2007.

⁴² Strictly speaking, MLPs make “distributions” to unit holders and corporations pay “dividends” to stockholders, but the DCF model makes no distinction between dividends and distributions. I have attempted to provide the alternate term, where appropriate, throughout the testimony.

⁴³ See *Williston Basin Interstate Pipeline Company*, 84 FERC ¶ 61,081, at 61,382 (1998).

1 **Q. Did you adjust the dividend (or distribution) yield to account for periodic**
2 **growth in dividends (or distributions)?**

3 A. Yes. Since companies tend to increase their quarterly dividends (or distributions) at
4 different times throughout the year, it is reasonable to assume that such increases will
5 be evenly distributed over calendar quarters. Given that assumption, it is reasonable
6 to apply one-half of the expected annual dividend (or distribution) growth rate for
7 the purposes of calculating the expected dividend (or distribution) yield component
8 of the DCF model. This adjustment ensures that the expected yield is representative
9 of the coming 12-month period. Accordingly, the DCF estimates provided in
10 Exhibit No. SGS-77 reflect one-half of the expected near-term growth in the
11 dividend (or distribution) yield component of the model.

12 **B. DCF Growth Estimates**

13 **Q. Is it important to select appropriate measures of growth in applying the DCF**
14 **model?**

15 A. Yes. The general form of the DCF model assumes a single growth estimate in
16 perpetuity. Accordingly, in order to reduce the future growth rate to a single
17 measure, one must assume a constant payout ratio, and that earnings, dividends (or
18 distributions) and book value will all grow at the same constant rate. Over the long
19 run, however, dividend (or distribution) growth can only be sustained by earnings
20 growth. As noted by Brigham and Houston:

21 Growth in dividends occurs primarily as a result of growth in *earnings*
22 *per share* (EPS). Earnings growth, in turn, results from a number of
23 factors, including (1) inflation, (2) the amount of earnings the

1 company retains and invests, and (3) the rate of return the company
2 earns on its equity (ROE).⁴⁴

3
4 Consequently, it is important to focus on measures of earnings growth from
5 multiple, credible sources as an appropriate measure of future growth.

6 **Q. Why do you rely on forecasted, as opposed to historical, growth rates as the**
7 **basis for your growth rate projections?**

8 A. The ROE is a forward-looking concept that focuses on investor expectations
9 regarding future returns. The estimation of such returns, therefore, should be based
10 on forward-looking or projected data. Indeed, substantial academic research has
11 demonstrated the relationship between analysts' forecasts and investor
12 expectations.⁴⁵ In my view, I/B/E/S earnings growth rates, a source which provides
13 a consensus estimate of earnings growth by collecting five-year earnings growth
14 forecasts from a large pool of analysts on approximately 5,000 companies, and also a
15 source commonly used by the Commission in ROE proceedings, provide a
16 reasonable measure of growth estimates for use in the DCF model.

17 **Q. What sources of near-term growth have you used in your DCF analysis?**

18 A. In keeping with the Commission's preference, I have used the five-year growth
19 estimates in earnings per share published by I/B/E/S.⁴⁶

⁴⁴ Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western) [emphasis added].

⁴⁵ See, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, *Financial Management* (Spring 1986) at 59. In a review of literature regarding the extent to which analyst forecasts are reflected in stock prices, Harris noted: "...Vander Weide and Carleton recently compare consensus financial analyst forecasts of earnings growth to 41 different historical growth measures. They conclude that "there is overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price...consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions."

⁴⁶ Opinion No. 414-A, 84 FERC ¶ 61,084, (1998).

1 **Q. How did you incorporate your near-term growth forecasts into the two-stage**
2 **DCF analysis?**

3 A. In *Williston Basin* (84 FERC ¶ 61,081), the Commission affirmed the use of a simple
4 average of the near and long-term growth rate forecasts. Subsequently, in Opinion
5 No. 414-A, the Commission modified the two-stage DCF analysis to “give greater
6 weight to the short-term growth rate than to the long-term growth rate.”⁴⁷ That
7 approach, which applied weights of two-thirds and one-third to a short-term and
8 long-term forecast, respectively, was affirmed in Opinion 414-B.⁴⁸ Consistent with
9 the Commission’s practice, therefore, I have given my near-term growth estimates,
10 based on I/B/E/S estimates, a weighting factor of two-thirds (as discussed below,
11 my long-term growth estimate is given a weighting factor of one-third).

12 **Q. How did you develop your long-term growth rate estimate?**

13 A. In Opinion No. 414-A⁴⁹ the Commission indicated a clear preference for the use of
14 measures of long-term Gross Domestic Product (“GDP”) growth as the long-term
15 component of the growth estimate. That Opinion affirmed the Commission’s
16 findings in *Williston Basin* that GDP is an appropriate estimate of long-term growth
17 because:

18 ...as companies reach maturity over the long-term, their growth
19 slows, and their growth rate will approach that of the economy as a
20 whole; second, the Commission concluded that, over the long-run, an
21 expectation that a regulated firm will grow at the rate of the average
22 firm in the economy is reasonable; third, the purpose of using the
23 DCF analysis in this proceeding is to approximate the rate of return
24 an investor would reasonably expect from a pipeline company, and
25 record in those proceedings showed that the long-term growth of the

⁴⁷ Ibid.

⁴⁸ Opinion No. 414-B, 85 FERC ¶ 61,323 at 62,269-70.

⁴⁹ Id.

1 economy is used by two large investment houses as their long-term
2 growth figure in conducting DCF analyses for investment purposes;
3 and fourth, witnesses in those proceedings used the long-term
4 growth of the economy as a whole as confirmation or support for
5 their analyses.⁵⁰
6

7 It is important to note, however, that while GDP growth may well provide a
8 reasonable estimate of long-term earnings growth, it is not necessarily the case that
9 earnings growth will equal revenue growth over the long term. It is worthy of note
10 that the Blue Chip Economic Indicators consensus forecast indicates that over the
11 latter portion of Blue Chip's forecast period, pre-tax income is expected to grow at
12 an annual rate of approximately 5.7 percent. While I have not included a separate
13 pre-tax income growth rate in my two-stage DCF model, I have considered that data
14 in forming my estimate of long-term growth.

15 **Q. What sources did you consider for your long-term growth rate estimate?**

16 A. My long-term growth estimate is derived from (1) the *Annual Energy Outlook*,
17 published by the Energy Information Administration; and (2) Blue Chip Economic
18 Indicators Consensus Forecast; and (3) a market-based inflation estimate based on
19 the difference between 10-year Treasuries and 10-year Treasury Inflation Protected
20 Securities ("TIPS").⁵¹ The simple average of those three inflation adjusted sources
21 produces a long-term nominal GDP growth rate of 5.36 percent. This is
22 approximately a 34 basis point difference from the pretax income growth rate
23 discussed above.

⁵⁰ 84 FERC ¶ 61,081, at 61,385.

⁵¹ The difference in 10-year Treasury yield and the year on 10-year TIPS is often considered to be as estimate of long-term inflation expectations. Nominal GDP growth is calculated as the product of $(1+i) \times (1+g)$ where i is the expected inflation rate and g is the long-term real GDP growth rate.

1 **Q. Please explain how you applied the DCF model to the MLPs.**

2 A. An MLP is a limited partnership, whose partnership interests are represented by
3 units that are publicly traded, much the same as a stock price represents a
4 shareholder's interests in a corporation. As discussed earlier, MLPs do not pay
5 dividends, but rather make distributions to its limited partnership unit holders. I
6 have applied the distribution per unit in the DCF model in the same way that I have
7 applied the dividend yield per share of common stock. In addition, I have addressed
8 the quarterly payment of distributions and dividends in the same way, by multiplying
9 the dividend or distribution yield by $1 + \frac{1}{2}$ of the growth rate to obtain the expected
10 distribution yield. The cash distributions that are received by the unit holders are
11 analogous to dividends received by common shareholders. In both situations the
12 return to the investor is the cash flow received in quarterly distributions plus the cash
13 that would be received if the units or shares were sold upon a given valuation date.

14 **Q. Please summarize your application of the two-stage DCF model.**

15 A. I calculated the DCF result for each of the proxy group companies using the
16 following inputs:

- 17 1) Based on Commission precedent,⁵² I have averaged the nearest six monthly
18 low and high stock (or unit) prices for the period ended June 30, 2007. This
19 is the most current data available to obtain a perspective on market
20 conditions as I prepare my testimony for the term *P*;
- 21 2) The current annualized dividend (or distribution) per share as of June 30,
22 2007;
- 23 3) I have used the I/B/E/S forecast for each of the proxy group companies as
24 the short-term forecast growth rate;
- 25 4) I have used the simple average of the long-term nominal GDP forecast by
26 the EIA, Blue Chip Economic Indicators, and inflation, measured as the

⁵² Order rejecting partial settlement, establishing transportation and storage rates, and directing filings in *Cranberry Pipeline Corp.*, 112 FERC ¶ 61,268 (2005).

1 difference between 10-year Treasuries and the TIPS as the long-term forecast
2 growth rate.

3 As discussed earlier, I adjusted the six-month average dividend yield by one half of
4 the expected short-term growth rate to arrive at the expected dividend yield
5 component of the model. Finally, in accordance with the Commission's past
6 practice, I applied weights of two-thirds and one-third to the short-term and long-
7 term forecast growth rates, respectively. Please refer to Exhibit No. SGS-77 for a
8 tabulation of dividend yields and growth rates used in my DCF analysis.

9 **Q. Please explain the approach by which you calculated your range of results.**

10 A. I calculated my range of results in accordance with the Commission's past practice,
11 which is to say that I calculated the two-stage DCF result for each company in the
12 proxy group. I then established the range of reasonableness by reference to the low
13 and high results of the group.

14 **C. DCF Results**

15 **Q. Please describe the results of your DCF analysis.**

16 A. Based on all the factors discussed in my testimony, and as shown in Exhibit No.
17 SGS-77, I have established a zone of reasonableness that is based on the high and
18 low DCF results, for the comparable companies, from approximately 11.00 percent
19 to 13.60 percent. I have tabulated the alternative measures of central tendency for
20 my proxy group in Table 3 (below) based on both the Commission's averaging
21 convention⁵³ and the simple 180-day average stock price.

⁵³ The Commission has typically relied on a six month average that is based on the average of six monthly data points, calculated based on the average of the high and the low stock price each month for the six month period.

Table 3: DCF Results

	Low	Mean	Median	Mid-point	High
DCF Results	10.93%	12.09%	12.03%	12.22%	13.50%
DCF Result 180 – Day Average Stock Price ⁵⁴	10.94%	12.20%	12.16%	12.26%	13.59%

Q. Did you undertake an additional supplemental analysis to validate your DCF model results?

A. Yes. I used the Bond Yield Plus Risk Premium approach to validate the results of my DCF analysis.

Q. Why is it important to use multiple methodologies when calculating the cost of equity?

A. Each of the models available to estimate the cost of equity is subject to its own set of assumptions or methodological constraints. For example, while the two-stage DCF model uses market-derived yield data, it also assumes a constant (albeit, weighted) growth rate in perpetuity. Consequently, many finance texts recommend using multiple approaches when estimating the cost of equity. Copeland, Koller and Murrin,⁵⁵ for example, suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski⁵⁶, for example, recommend the CAPM, the DCF, and the Bond Yield Plus Risk Premium approaches. Since each model requires the use of considerable judgment regarding assumptions and the validity of proxy entities, it is prudent to use multiple methodologies to mitigate the effects of assumptions and

⁵⁴ 180-day average is calculated as the simple average of 180 trading days.

⁵⁵ Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, 3rd ed. (New York: McKinsey & Company, Inc., 2000) 214.

⁵⁶ Eugene Brigham, Louis Gapenski, *Financial Management: Theory and Practice*, 7th Ed. (Orlando: Dryden Press, 1994) 341.

1 inputs associated with any single approach. Based on the Commission's preference
2 for the two-stage DCF model and in light of the capital market practices discussed
3 above, the two-stage DCF, supported by the results of the Bond Yield Plus Risk
4 Premium analyses, is a reasonable methodological approach to establish Southwest
5 Gas Storage's cost of equity.

6 **Q. Please describe the bond yield plus risk premium approach you employed.**

7 A. This approach estimates the cost of equity as the sum of the estimated risk premium
8 and the yield on a particular class of bonds. Since the equity risk premium is not
9 directly observable, it typically is estimated using one of a variety of approaches that
10 in itself must incorporate an estimate of the cost of equity in the analysis. Inasmuch
11 as any such approach necessarily introduces an additional element of estimation
12 error, an alternative approach is to use the actual authorized returns for natural gas
13 pipelines as the historical measure of the cost of equity. Since both authorized
14 returns and Treasury yields are observable, this approach substantially mitigates the
15 estimation error that otherwise may be included in the analysis.

16 **Q. Are there other analytical considerations that should be addressed in**
17 **conducting this analysis?**

18 A. Yes. In my view, it is important to recognize both academic and market evidence
19 suggesting that the equity risk premium (as used in this approach) is inversely related
20 to the level of interest rates. That is, as interest rates increase (decrease), the equity
21 risk premium decreases (increases). Consequently, it is important to develop an
22 analysis that (1) reflects the inverse relationship between interest rates and the equity
23 risk premium and (2) is based on more recent market conditions. Such an analysis

1 can be developed based on a regression of the risk premium as a function of
2 Treasury yields. If we let allowed natural gas pipeline ROEs serve as the measure of
3 required equity returns and define the yield on ten-year Treasury Notes as the
4 relevant measure of interest rates, the risk premium simply would be the difference
5 between those two points.⁵⁷

6 **Q. What did your bond yield plus risk premium analysis reveal?**

7 A. As shown on Chart 8 (below), from 1992 through 2006 there was, in fact, a strong
8 negative relationship between the equity risk premium and interest rates. To
9 estimate that relationship, I conducted a regression analysis using the following
10 equation:

11
$$RP = a + b(T_{10}) [2]$$

12 where:

13 RP = Risk Premium (difference between allowed ROEs and 10-year
14 Treasury yield)

15 a = Intercept Term

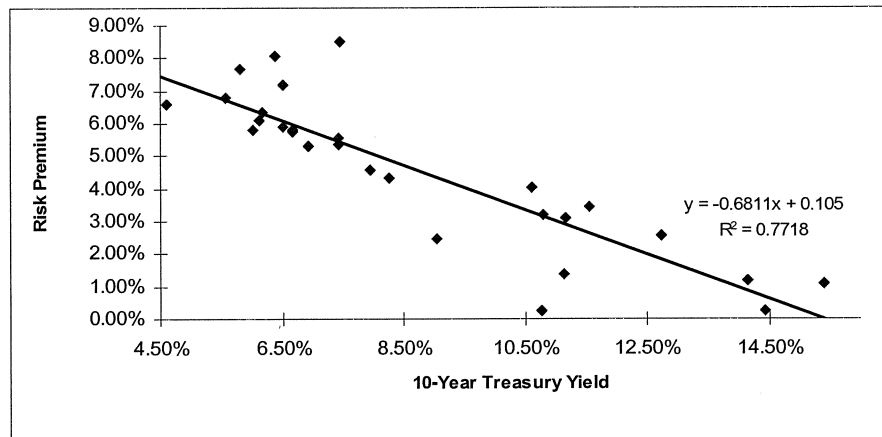
16 b = Slope Term

17 T_{10} = 10-year Treasury Bond Yield
18

19 Data regarding allowed ROEs was derived from 30 rate cases from 1976 through the
20 fourth quarter of 2006. This equation and its coefficients were statistically
21 significant, with an R^2 of 0.77.

⁵⁷ See for example, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. See also Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

Chart 8: Risk Premium vs. Interest Rates⁵⁸



As shown in Exhibit No. SGS-78, from 1976 through the fourth quarter of 2006 the average risk premium was approximately 6.96 percent. As shown in Exhibit No. SGS-78, adding the risk premium to the Blue Chip forecasted risk-free rate results in an ROE of 12.16 percent, which is consistent with the median DCF results but does not reflect the additional business risks faced by Southwest Gas Storage.

Q. Have there been recent changes in the Commission's position regarding use of MLP entities in proxy groups for return on equity analysis?

A. Yes. On July 19, 2007, the Commission issued a Proposed Policy Statement in Docket No. PL07-2-000, addressing the composition of proxy groups for determining gas and oil pipeline return on equity. In the Proposed Policy Statement, the Commission is proposing to update its standards concerning the composition of the proxy groups used to decide the return on equity (ROE) of natural gas and oil pipelines, since firms engaged in the pipeline business are increasingly organized as

⁵⁸ Source: Northwest Pipeline Corporation, Docket RP06-416, Prepared Direct Testimony of Charles Olson, Exhibit No. NWP-43; data provided in Dr. Olson's testimony were corroborated by reference to Commission Orders.

1 master limited partnerships (MLPs). Therefore, the Commission proposes to modify
2 its current policy regarding the composition of proxy groups to allow MLPs to be
3 included in the proxy group.

4 **Q. What is the Commission's primary concern with the inclusion of MLP's in the**
5 **proxy group for the purposes of setting a natural gas pipeline return on**
6 **equity?**

7 A. The Commission identified three concerns with the use of MLPs in the proxy group:

8 1) to the extent that an MLP pays distributions that exceed the earnings, it can do so
9 because of because partnership agreements define "cash available for distribution" to
10 include depreciation. The Commission is concerned that the use of depreciation to
11 increase distributions above earnings is a return *of* capital, whereas the DCF analysis
12 is seeking the appropriate return *on* capital, 2) corporations generally do not pay out
13 all of their earnings in dividends, but retain some earnings in order to generate future
14 growth, 3) the DCF model is premised on growth in dividends deriving from
15 reinvestment of current earnings, and does not incorporate growth from external
16 sources, such as issuing debt or additional stock.

17 As noted in this testimony, there is ample reason to simply accept the MLP
18 distributions as they exist. However, the Commission has invited comments on its
19 proposed policy statement, and other proposals may be made that point to
20 adjustments that have not been identified. As such, once the Commission received
21 all comments, and issues a final policy statement, there may be further analysis
22 needed to the proxy group I have identified herein. However, my analysis to date has

1 addressed many of the concerns identified by the Commission in the proposed
2 policy statement.

3 **VII. SUMMARY AND CONCLUSIONS**

4 **Q. Please summarize your recommended ROE for Southwest Gas Storage.**

5 A. Based on all the factors discussed in my testimony, I find that the zone of
6 reasonableness is from approximately 11.00 percent to approximately 13.50 percent.
7 The median of that range, which is approximately 12.00 percent, represents the ROE
8 for a natural gas pipeline of average risk. The 180-day stock price averaging
9 convention results in a zone of reasonableness from approximately 11.00 percent to
10 13.60 percent, with a median of approximately 12.20 percent. As noted earlier, the
11 Company's risk profile requires that a return at above the median results for the
12 pipeline group. In my view, therefore the Company should be provided the
13 opportunity to earn a return of 13.00 percent on its equity capital.

14 **Q. Does this conclude your prepared direct testimony?**

15 A. Yes, it does.


Commonwealth of Massachusetts }
 }
County of Middlesex } SS.

BEFORE ME, the undersigned authority, on this day personally appeared
Robert B. Hevert, who being by me first duly sworn, on oath deposes and says:

That he is the Robert B. Hevert, offering the foregoing prepared direct testimony
and that all statements of fact contained therein are true and correct to the best of his
knowledge, information and belief.

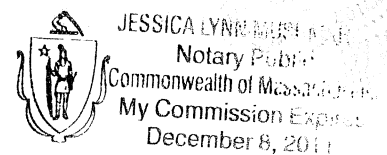

Robert B. Hevert

Subscribed and sworn to before me this 26th day of July, 2007.


Notary Public

My Commission Expires:

Dec. 8, 2011



Robert B. Hevert, CFA
President

Mr. Hevert is an economic and financial consultant with broad experience in the energy industry. He has an extensive background in the areas of corporate strategic planning, energy market assessment, corporate finance, mergers, and acquisitions, asset-based transactions, asset and business unit valuation, market entry strategies, strategic alliances, project development, feasibility and due diligence analyses. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negotiations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured

and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Representative non-confidential clients have included:

- Conectiv generation asset divestiture
- Eastern Utilities Associates (prior to acquisition by National Grid, PLC) generation asset divestiture
- Niagara Mohawk – sale of Niagara Mohawk Energy
- Potomac Electric Company generation asset divestiture

Representative confidential engagements have included:

- Buy-side valuation and assessment of merchant generation assets in Midwestern US
- Buy-side due diligence and valuation of wholesale energy marketing companies in Eastern and Midwestern US
- Buy-side due diligence of natural gas distribution assets in Northeastern US
- Financial feasibility study of natural gas pipeline in upper Midwestern US
- Financial valuation of natural gas pipeline in Southwestern US

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Also performed rate of return and cost of service analyses for municipally owned gas and electric utilities. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Representative engagements have included:

- Performing rate of return analyses for use in cost of service analyses on behalf of municipally owned gas and electric utilities in the Southeastern and Midwestern US
- Developing merchant function exit strategies for Northeastern US natural gas distribution companies
- Developing regulatory and ratemaking strategy for mergers including several Northeastern natural gas distribution companies

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including the proposed transfer of power purchase agreements, procurement of residual service electric supply, the legal separation of generation assets, and specific financing transactions. Services provided also included collaborating with counsel, business and technical staff to develop litigation strategies,

preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the US and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Representative engagements have included:

- Managing assessments of the NYPOOL, NEPOOL and PJM markets for major North American energy companies considering entering or expanding their presence in those markets
- Assessment of ECAR, MAPP, MAIN and SPP markets for a large US integrated utility considering acquisition of additional electric generation assets
- Assessment of natural gas pipeline and storage capacity in the SERC and FRCC markets for a major international energy company

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, Energy Ventures, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

Representative engagements have included:

- Developing and facilitating executive level strategic planning retreats for Northeastern natural gas distribution companies
- Developing organization and business process redesign plans for municipally owned gas/electric/water utility in the Southeastern US
- Reviewing and revising corporate merchant generation business plans for Canadian and US integrated utilities
- Advising client personnel in development of business unit level strategic plans for various natural gas distribution companies

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

President

Navigant Consulting, Inc. (1997 – 2001)

Managing Director (2000 – 2001)

Director (1998 – 2000)

Vice President, REED Consulting Group (1997 – 1998)

REED Consulting Group (1997)

Vice President

Bay State Gas Company (1987 – 1997)

Vice President, Energy Ventures and Assistant Treasurer

Boston College (1986 – 1987)

Financial Analyst

General Telephone Company of the South (1984 – 1986)

Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984

B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991

Association for Investment Management and Research

Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
- Retail and Wholesale Market Entry Strategies
- The Use Strategic Alliances in Restructured Energy Markets
- Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
- Nuclear Asset Valuation and the Divestiture Process

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

EXPERT TESTIMONY OF ROBERT B. HEVERT

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Sea Robin Pipeline Company, LLC	6/07	Sea Robin Pipeline Company, LLC	Docket No. RP07-513-000	Return on Equity
Southwest Gas Storage Company	6/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas	01/07	Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
Xcel Energy	12/06	Public Service Company of Colorado	Docket No. 06S-__G	Return on Equity (gas)
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	Return on Equity
Pepco Holdings, Inc.	9/06	Atlantic City Electric		Divestiture and Valuation of Electric Generating Assets
Columbia Gas Of Virginia, Inc.	6/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Xcel Energy	5/06	Southwestern Public Service	SOAH Docket No. 473-06-2536 Docket No. 32766	Return on Equity (electric)
Xcel Energy	4/06	Public Service Company of Colorado	Docket No. 06S-__E	Return on Equity (electric)
Green Mountain Power	4/06	Green Mountain Power		Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket No. 7109 and No. 7160 (Vermont)	Return on Equity (gas)
Pepco Holdings, Inc.	12/05	Atlantic City Electric	BPU Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Xcel Energy	11/05	NSP-Minnesota	Docket No. E002/GR-05-1428 (Minnesota)	Return on Equity (electric)
Xcel Energy	08/05	Public Service Company of Colorado	Advice Letter No. 94-Steam (Colorado)	Return on Equity (steam)
Xcel Energy	05/05	Public Service Company of Colorado	Docket No. 05-264G (Colorado)	Return on Equity (gas)

EXPERT TESTIMONY OF ROBERT B. HEVERT

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
NSTAR Electric	09/04	NSTAR Electric	D.T.E 04-85 (Massachusetts)	Divestiture of Power Purchase Agreement
Xcel Energy	09/04	NSP Minnesota	G002/GR-04-1511 (Minnesota)	Cost of Capital (gas)
NSTAR Electric	08/04	NSTAR Electric	D.T.E 04-78 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	D.T.E 04-68 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	D.T.E 04-61 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	D.T.E 04-60 (Massachusetts)	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	D.T.E. 03-52 (Massachusetts)	Integrated Resource Plan; Gas Demand Forecast
Conectiv	06/03	Atlantic City Electric Company	BPU EO03020091 (New Jersey)	Market Value of Electric Generation Assets; Auction Process
Dominion Resources	10/01	Virginia Electric and Power Company	PUE000584 (Virginia)	Corporate Structure and Electric Generation Strategy
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	NY PSC Case 01-E	Power Purchase and Sale Agreement; Standard Offer Service Agreement
GPU International and Aquila	11/00	GPU International	EC01- (FERC)	Market Power Study
Northern Utilities, Inc.	07/95	Northern Utilities	Maine PUC	Gas Distribution System Expansion
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Long Term Debt Financing
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Long Term Debt Financing

EL PASO CORPORATION TWO-STAGE CONSTANT GROWTH DCF									
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	I/B/E/S Consensus Growth	GDP Growth	Weighted Average Growth Rate *	DCF
El Paso Corp	EP	\$0.16	\$15.36	1.04%	1.08%	8.00%	5.36%	7.12%	8.20%

Notes

- [1] Source: Yahoo! Finance
- [2] Source: Yahoo! Finance.
- [3] Equals Col. [1]/Col. [2]
- [4] Equals Col. [3] x (1+ (.5 x Col. [5]))
- [5] Source: Thomson Research
- [6] Average of EIA AEO, and Blue Chip Forecast
- [7] Equals Col [5] x (2/3)+ Col [6] x (1/3)
- [8] Equals Col. [4] + Col. [7]

THE WILLIAMS COMPANIES TWO-STAGE CONSTANT GROWTH DCF

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	I/B/E/S Consensus Growth	GDP Growth	Weighted Average Growth Rate	
Williams Companies	WMB \$0.40	\$28.51	1.40%	1.48%	11.50%	5.36%	9.45%	10.93%

Notes

- [1] Source: Yahoo! Finance
[2] Source: Yahoo! Finance.
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [3] x (1+ (.5 x Col. [5]))
[5] Source: Thomson Research
[6] Average of EIA AEO, and Blue Chip Forecast
[7] Equals Col [5] x (2/3)+ Col [6] x (1/3)
[8] Equals Col. [4] + Col. [7]

Williams Weighted Average Cost of Debt 7.59%

Risk Premium 3.34%

THE WILLIAMS COMPANIES WEIGHTED AVERAGE COST OF DEBT

	<u>Interest Rate</u>	<u>Principal</u>	<u>% of Total Debt</u>	<u>Weighted Interest Rate</u>
Secured (2)				
6.62%-9.45%, payable through 2016	8.00%	\$ 171.70	2.14%	0.17%
Adjustable rate, payable through 2016	6.20%	\$ 74.40	0.93%	0.06%
Capital lease obligations	9.30%	\$ 2.50	0.03%	0.00%
Unsecured				
5.5%-10.25%, payable through 2033	7.60%	\$ 7,690.40	95.96%	7.29%
Adjustable rate, due 2008	6.70%	\$ 75.00	0.94%	0.06%
Other, payable through 2007	6.00%	\$ 0.10	0.00%	0.00%
Total Long-term debt, including current portion		\$ 8,014.10	100.00%	7.59%

Notes:

Source: WMB 2006 SEC FORM 10-K

PROXY GROUP SCREENING CRITERIA

	Ticker	Dividends	Covered by More than 1 Analyst	Owens 100% of major FERC- regulated pipeline	% Regulated natural gas transmission net income to total regulated net income	Merger	% NG Pipeline Revenue, Op Assets and Income	25% Natural Gas Transmission Assets, Op Income and Revenue
Boardwalk Pipeline Partners LP	BWP	Yes	Yes	Yes	Yes	No	Yes	Yes
Buckeye Partners LP	BPL	Yes	Yes	No	No	No	No	No
Cabot Oil and Gas	COG	Yes	Yes	No	No	No	No	No
Chesapeake Energy	CHK	Yes	Yes	No	No	No	No	No
Devon Energy	DVN	Yes	Yes	No	No	Yes	No	No
Dynegy Inc	DYN	No	Yes	No	No	Yes	No	No
El Paso Corp	EP	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Enbridge Energy Partners LP	EEP	Yes	Yes	Yes	No	No	Yes	Yes
Enbridge Inc	ENB	Yes	Yes	No	No	No	No	No
Energizer Corporation	EGN	Yes	Yes	No	No	No	No	No
Enterprise Products Partners LP	EPD	Yes	Yes	Yes	Yes	No	Yes	Yes
EOG Resources	EOG	Yes	Yes	No	No	No	No	No
Equitable Resources, Inc.	EQT	Yes	Yes	Yes	No	Yes	No	No
Kinder Morgan Energy Partners, L.P.	KMP	Yes	Yes	Yes	Yes	No	Yes	Yes
Magellan Midstream Partners LP	MMP	Yes	Yes	No	No	No	No	No
MarkWest Energy Partners, L.P.	MWE	Yes	Yes	Yes	Yes	No	Yes	Yes
National Fuel Gas Company	NFG	Yes	Yes	Yes	Yes	No	Yes	Yes
Newfield Exploration	NFX	No	Yes	No	No	Yes	No	No
OneOK Partners, L.P.	OKS	Yes	Yes	Yes	Yes	No	Yes	Yes
OneOK, Inc	OKI	Yes	Yes	No	No	No	No	No
Questar Corporation	STR	Yes	Yes	Yes	Yes	No	No	No
Southwestern Energy	SWN	No	Yes	No	No	No	No	No
Spectra Energy	SE	Yes	No	Yes	Yes	Yes	Yes	Yes
TC PipeLines L.P.	TCLP	Yes	Yes	No	Yes	Yes	No	Yes
TEPPCO Partners	TPP	Yes	Yes	Yes	No	Yes	Yes	Yes
Williams Companies	WMB	Yes	Yes	Yes	Yes	No	Yes	Yes
XTO Energy, Inc	XTO	Yes	Yes	No	No	Yes	No	No

GAS PIPELINE COMPANIES OWNED BY PROXY GROUP CANDIDATE COMPANIES

Proxy Group Company	Gas Transportation Companies/Pipelines	% Ownership	Capacity	Capacity units	Length (miles)
Williams Companies	Gulfstream	50%	1	MMcf/d	691
	Northwest Pipeline Corporation	100%	3	Bcf/d	3,900
	Transcontinental Gas Pipeline Corporation	100%	8	Bcf/d	10,500
Enterprise Products Partners, L.P.	San Juan Gathering System	100%	1,100	MMcf/d	5,404
	Permian Basin System	100%	490	MMcf/d	1,477
	High Island Offshore System	100%	1,800	MMcf/d	204
	NGL Pipelines				
	Mid-American Pipeline System	100%			7,378
	Dixie Pipeline	74%			1,370
	Seminole Pipeline	90%			1,326
	EPD South Texas NGL System	100%			1,039
	Louisiana Pipeline System	Various			612
	Promix NGL Gathering System	50%			362
	DEP South Texas NGL Pipeline System	100%			286
	Houston Ship Channel	100%			266
	Lou-Tex NGL	100%			204
	Other (5 Systems)	Various			452
	Onshore Natural Gas Pipelines				
	Texas Intrastate System	100%	5,155	MMcf/d	8,140
	Jonah Gathering System	14%	1,750	MMcf/d	643
	Piceance Creek Gathering System	100%	1,600	MMcf/d	48
	San Juan Gathering System	100%	1,200	MMcf/d	6,065
	Acadian Gas System	Various	954	MMcf/d	1,042
	Permian Basin System	100%	490	MMcf/d	1,387
	Alabama Intrastate System	100%	200	MMcf/d	408
	Encinal Gathering System	100%	143	MMcf/d	452
	Other (5 Systems)	Various			704
	Offshore Natural Gas Pipelines				
	VESCO Gathering System	13%	800	MMcf/d	260
	Manta Ray Offshore Gathering System	26%	206	MMcf/d	250
	High Island Offshore System	100%	1,800	MMcf/d	204
	Viosca Knoll Gathering System	100%	1,000	MMcf/d	164
	Green Canyon Laterals	Various	649	MMcf/d	136
	Anaconda Gathering System	100%	550	MMcf/d	136
	Independence Trail	100%	1,000	MMcf/d	134
	Nautilus System	26%	154	MMcf/d	101
	East Breaks System	100%	400	MMcf/d	85
	Phoenix Gathering System	100%	450	MMcf/d	78
	Nemo Gathering System	34%	102	MMcf/d	24
	Falcon Natural Gas Pipeline	100%	400	MMcf/d	14

GAS PIPELINE COMPANIES OWNED BY PROXY GROUP CANDIDATE COMPANIES

Proxy Group Company	Gas Transportation Companies/Pipelines	% Ownership	Capacity	Capacity units	Length (miles)
Kinder Morgan Energy Partners, L.P.	Kinder Morgan Interstate Gas Transmission	100%	169	MDth/d	5,100
	Rockies Express Pipeline	51%	1,800	MMcf/d	1,662
	Trailblazer Pipeline Company	100%	846	MMcf/d	436
	Pacific Operations	100%	1	Mbpd	
	West Line	100%			515
	East Line	100%			420
	San Diego Line	100%			135
	CALNEV Line	100%			303
	North Line	100%			864
	Bakersfield Line	100%			100
	Oregon Line	100%			114
	Plantation Pipeline Company	51%	555,060	Mbpd	3,100
	Central Florida Pipeline	100%	112,000	bpd	110
	North System	100%	8	Mbpd	1,600
	Cochin Pipeline System	50%	124,000	bpd	1,900
	Cypress Pipeline	100%	30,000	bpd	104
	Southeast Terminals	100%	347,000	bpd	
	Kinder Morgan Southeast Terminals	100%			
	Guilford County Terminal Co.	100%			
	Texas Intrastate Natural Gas Pipeline Group	100%			
	Kinder Morgan Texas Pipeline	100%	5,200	MMcf/d	6,000
	Kinder Morgan Tejas Pipeline	100%	300	MMcf/d	97
	Mierr-Monterrey Mexico Pipeline	100%	735	MMcf/d	95
	Kinder Morgan North Texas Pipeline	100%	325	MMcf/d	86
	TransColorado Gas Transmission Company	100%	869	MMcf/d	300
	Kinder Morgan Louisiana Pipeline	100%	3,200	MMcf/d	133
	Casper and Douglas Natural Gas	100%	185	MMcf/d	
	Red Cedar Gathering Company	49%	250	MMcf/d	
	Thunder Creek Gas Services	25%	240	MMcf/d	549
	Trailblazer Pipeline Company	100%	730	MMcf/d	436
	Rockies Express Pipeline	51%	1,500	MMcf/d	1,662
Boardwalk Pipeline Partners, L.P.	Texas Gas Transmission Company	100%	3	Bcf/d	5,900
	Gulf South Pipeline	100%	4	Bcf/d	7,570
Enbridge Energy Partners, L.P.	Enbridge Pipelines (AlaTenn)	100%	200	MMcf/d	218
	Enbridge Pipelines (Midla)	100%	200	MMcf/d	405
	Enbridge Pipelines (KPC)	100%	160	MMcf/d	1,120
	Enbridge Offshore Pipelines (UTOS)	100%	1,200	MMcf/d	30
OneOK Partners, L.P.	Northern Border Pipeline Company	50%	2,374	MMcf/d	1,249
	Midwestern Gas Transmission Company	100%	1,125	MMcf/d	350
	Viking Gas Transmission Company	100%	496	MMcf/d	578
	Guardian Pipeline	33 1/3%	750	MMcf/d	143
Boardwalk Pipeline Partners, L.P.	Texas Gas System	100%	3	Bcf/d	5,900
	Gulf South System	100%	4	Bcf/d	7,500
	Expansion Projects (projects under construction)				
	Carthage to Keatchie Loop	100%	120	MMcf/d	25
	East Texas to Mississippi	100%	2	Bcf/d	242
	Gulf Crossing Project		2	Bcf/d	355
	Southeast Expansion	100%	2	Bcf/d	112
Enbridge Energy Partners	Fayetteville Shale	100%	800	MMcf/d	165
	Crude Oil				
	Lakehead System	100%	350,000	Bpd	3,300
	Mid-Continent System	100%	244,000	Bpd	480
	North Dakota System	100%	95,000	Bpd	950
	Natural Gas				
	East Texas System		1,300	MMcf/d	2,900
	Anadarko System		440	MMcf/d	1,200
	North Texas System		1,800	MMcf/d	4,200

GAS PIPELINE COMPANIES OWNED BY PROXY GROUP CANDIDATE COMPANIES

Proxy Group Company	Gas Transportation Companies/Pipelines	% Ownership	Capacity	Capacity units	Length (miles)
MarkWest Energy Partners LP	Southwest Business Unit				
	East Texas	100%	401,400	MMcf/d	
	Forest Lake	100%	95,200	MMcf/d	
	Woodford	100%	51,200	MMcf/d	
	Grimes	100%	12,700	MMcf/d	
	Northeast Business Unit				
	Appalachia	100%	203,400	MMcf/d	
	Michigan	100%	6,000	MMcf/d	
	Gulf Coast Business Unit				
	Javelina	100%	2,800	NGLs/d	
	Starfish Pipeline Company	50%			
Chesapeake Energy Corp.	Mid-Continent/Appalachian region	100%			8,000
Buckeye Partners L.P.	Buckeye Pipe Line Company, L.P.	100%			2,463
	Laurel Pipe Line Company, L.P.	100%			345
	Wood River Pipe Lines LLC	100%			925
	Buck Eye Pipe Line Transportation	100%			478
	Everglades Pipe Line Company, L.P.	100%			37
	Buckeye NGL Pipe Lines LLC	100%			350
	Buckeye Pipe Line Holdings, L.P.	100%			574
	Buckeye and Norco Pipe Line Company, LLC				
Enbridge, Inc.	Olympic Pipe Line	65%	290,000	Bpd	400
	Alliance Pipeline	100%	1	Bcf/d	1,875
	Vector Pipeline	100%	2	Bcf/d	348
	Enbridge Offshore Pipelines	100%	2	Bcf/d	1,500
Magellan Midstream Partners L.P.					8,500

PROXY GROUP BUSINESS SEGMENTS

Williams Companies

	Total	Power	Gas Pipeline	Exploration and Production	Midstream Gas and Liquids	Other	Eliminations	Power	Gas Pipeline	Exploration and Production	Midstream Gas and Liquids	Other	Eliminations	Total
Williams Co. Segment Revenues	2006 11,813	7,462	1,348	1,488	4,125	27	(2,636.0)	63%	11%	13%	35%	0%	-23%	100%
	2005 12,583.6	9,059.9	1,412.8	3,232.7	27.2	(2,452.1)	72%	72%	11%	10%	26%	0%	-19%	100%
	2004 12,461.3	9,272.4	1,362.3	777.6	2,882.6	32.8	(1,866.4)	74%	74%	6%	23%	0%	-15%	100%
Williams Co. Segment Operating Income	2006 1,369.4	(224)	430	530	631	2		-16%	31%	39%	46%	0%	0%	100%
	2005 1,326.0	(216.8)	542.2	568.4	446.6	5.6		-18%	41%	43%	34%	0%	0%	100%
	2004 1,405.7	86.5	557.6	223.9	552.2	(14.5)		6%	40%	16%	39%	-1%	0%	100%
Williams Co. Segment Assets	2006 YTD 25,604,400	9,719,800	8,095,600	7,671,800	5,349,000	3,617,400	(8,849,200)	38%	32%	30%	21%	14%	-33%	100%
	2005 23,499.8	14,989.2	7,581.0	4,672.0	3,525.9			38%	30%	17%	12%	10%	0%	100%
	2004 20,228.0	8,294.1	7,621.8	5,576.4	4,421.7	2,387.0		27%	27%	20%	15%	7%	0%	100%
								32%	25%	22%	28%	4%	-10%	100%

Enterprise Products Partners, L.P.

	Total	Offshore Pipelines and Services	Onshore Pipelines and Services	NGL Pipelines and Services	Petrochemical Services	Adjustments and Eliminations	Offshore Pipelines and Services	Onshore Pipelines and Services	NGL Pipelines and Services	Petrochemical Services	Adjustments and Eliminations	Total
Enterprise Segment Revenues	2006 16,732,183	776,268	6,577,661	736,524	8,641,730	2,340,022	1%	8%	62%	10%	20%	0%
2005 9,787,128	711,886	7,718,384	657,594	699,264	4,603,341	3,724,130	1%	8%	63%	10%	19%	0%
2004 7,932,861	645,249	6,252,921	492,834	541,857	1,933,608	(2,597,425)	0%	10%	98%	20%	-28%	0%
Enterprise Segment Operating Income	2006 1,362,449	103,407	333,399	752,548	173,095	-	8%	24%	55%	13%	0%	0%
2005 1,136,347	77,505	353,076	579,706	126,060	-	-	7%	31%	51%	11%	0%	0%
2004 623,166	36,478	90,977	374,156	121,515	-	-	6%	15%	60%	19%	0%	0%
Enterprise Segment Assets	2006 9,832,547	734,659	3,611,974	3,249,486	502,345	1,734,083	7%	37%	33%	5%	18%	0%
2005 8,689,024	632,222	3,622,318	3,075,048	504,441	854,095		7%	42%	35%	6%	10%	0%
2004 7,831,467	648,181	3,729,650	2,753,934	469,327	230,375		8%	48%	35%	6%	3%	0%
							5%	25%	55%	11%	5%	0%

Kinder Morgan Energy Partners, L.P.

	Total	Products Pipelines	Natural Gas Pipelines	Terminals	CO ₂	Terminals	Products Pipelines	Natural Gas Pipelines	CO ₂	Terminals	Total
Kinder Morgan Energy Partners Segment Revenues	2006 16,732,183	776,268	6,577,661	736,524	8,641,730	2,340,022	5%	39%	4%	52%	100%
2005 9,787,128	711,886	7,718,384	657,594	699,264	4,603,341	3,724,130	7%	79%	7%	7%	100%
2004 7,932,861	645,249	6,252,921	492,834	541,857	1,933,608	(2,597,425)	8%	79%	6%	7%	100%
Kinder Morgan Energy Partners Operating Income	2006 1,362,449	103,407	333,399	752,548	173,095	-	26%	33%	19%	22%	100%
2005 1,300,398	287,505	438,386	318,980	255,529	333,592	235,529	22%	34%	25%	20%	100%
2004 1,208,299	370,321	364,872	238,488	238,488	333,592	235,529	31%	30%	19%	20%	100%
Kinder Morgan Energy Partners Segment Assets	2006 12,055,622	3,910,612	3,942,786	1,838,231	2,364,001	3,942,786	32%	33%	15%	20%	100%
2005 11,839,121	3,873,939	4,139,969	1,772,766	2,052,457	3,873,939	4,139,969	33%	35%	15%	17%	100%
2004 10,447,257	3,651,657	3,691,457	1,527,810	1,527,810	3,651,657	1,527,810	35%	35%	15%	15%	100%
							22%	44%	14%	20%	100%

Boardwalk Pipeline Partners, L.P.

	Total	Gas Transportation	Parking and Lending	Gas Storage	Other	Gas Transportation	Parking and Lending	Gas Storage	Other	Total
Boardwalk Segment Revenues	2006 607,642	508,241	49,163	32,396	17,842	8%	8%	5%	3%	100%
2005 560,466	503,148	21,687	21,426	12,225	12,225	4%	4%	4%	2%	100%
2004 265,021	253,488	7,289	2,844	2,844	2,844	96%	0%	3%	1%	100%
Boardwalk Segment Assets	2006 2,403,143	1,826,636	195,800	378,707	345,001	76%	0%	8%	16%	100%
2005 1,881,350	1,407,055	129,294	345,001	345,001	129,294	75%	0%	7%	18%	100%
2004 1,891,924	1,407,055	129,294	345,001	345,001	129,294	74%	0%	7%	19%	100%
						84%	2%	5%	8%	100%

[1] Average excludes Operating Income and 2005 Segment assets

PROXY GROUP BUSINESS SEGMENTS

Enbridge Energy Partners, L.P.

	Total	Liquids	Natural Gas	Marketing	Corporate	Oil and Natural Gas Liquids Transportation	Natural Gas Gathering, Processing and Storage	Marketing	Corporate	Total
Enbridge Segment Revenues	2006 9,609.2 2005 9,247.3 2004 5,986.3	512.8 418.0 409.3	5,404.1 4,915.1 2,890.1	3,182.3 3,884.2 2,686.9	- - -	5% 5% 7%	6% 5% 7%	35% 42% 45%	0% 0% 0%	100% 100% 100%
Enbridge Operating Income	2006 386.9 2005 195.1 2004 237.2	199.8 127.3 139.1	133.9 110.5 98.1	56.1 (42.4) 3.6	(2.9) (0.4) (3.6)	52% 65% 65%	35% 57% 57%	14% -22% -22%	-1% 0% 0%	100% 100% 100%
Enbridge Segment Assets	2006 5,223.8 2005 4,428.4 2004 3,707.7	1,816.4 1,644.0 1,639.8	2,797.3 2,145.9 1,171.2	366.9 312.3 313.7	243.2 106.2 100.0	35% 38% 34%	35% 48% 51%	7% 12% 14%	5% 2% 1%	100% 100% 100%

OneOK Partners, L.P.

	Total	Interstate Natural Gas Pipeline	Natural Gas Gathering and Processing	Coal Slurry Pipeline	Natural Gas Liquids	Pipelines and Storage	Other	Interstate Natural Gas Pipeline	Natural Gas Processing	Coal Slurry Pipeline	Natural Gas Liquids	Pipelines and Storage	Other	Total
OneOK Partners Segment Revenues	2006 5,328,348 2005 4,765,960 2004 3,990,383	94,743 378,701 383,625	1,476,090 273,247 184,738	24,572 22,020 -	3,492,576 -	264,339 -	-	2% 26% 63%	3% 41% 31%	0% 4% 4%	66% 0% 0%	3% 0% 0%	0% 0% 0%	77% 100% 100%
OneOK Partners Operating Income	2006 535,357 2005 256,768 2004 253,385	158,505 214,168 231,027	180,242 44,714 28,278	5,186 3,446 -	88,691 -	107,919 -	(7,300) (9,360)	30% 83% 91%	34% 17% 11%	0% 2% 1%	17% 0% 0%	20% 0% 0%	0% -3% -4%	100% 100% 100%
OneOK Partners Segment Assets	2006 5,035,356 2005 2,527,766 2004 2,511,690	1,041,259 1,888,980 1,994,689	1,616,119 594,379 576,497	16,110 27,997 18,268	1,645,174 -	1,120,029 -	(387,529) 27,997 15,236	21% 75% 76%	32% 24% 23%	0% 1% 1%	33% 0% 0%	22% 0% 0%	-8% 0% 1%	100% 100% 97%

Markwest Energy

	Total	Starfish Pipeline	Total
Markwest Segment Revenues	2006 \$ 32,078 2005 \$ 19,343	\$ 32,078 \$ 19,343	100% 100%
Markwest Operating Income	2006 \$ 9,190 2005 \$ (728)	\$ 9,190 \$ (728)	100% 100%
Markwest Segment Assets	2006 \$ 147,177 2005 \$ 104,072	\$ 147,177 \$ 104,072	100% 100%

ANALYSIS OF BOOK VALUE PER UNIT FOR THE MLP GROUP

Name	Source / Calculation	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2012
Boardwalk Pipeline Partners, LP													
1	Earnings per Unit		ValueLine						\$ -	\$ 1.85	\$ 1.90	\$ 2.05	\$ 2.70
2	Cash Flow Per Unit		ValueLine						\$ 1.68	\$ 2.53	\$ 2.45	\$ 2.75	\$ 3.75
3	Distributions per Unit		ValueLine						\$ 0.18	\$ 1.32	\$ 1.74	\$ 1.86	\$ 2.42
4	Units Outstanding (millions)		ValueLine						101.35	108.25	118.00	120.00	128.00
5	Avg Annual P/E Ratio		ValueLine						19.7	13.3	16.0	16.0	16.0
6	Market Value Per Unit		[1] x [5]							\$ 24.61	\$ 30.40	\$ 32.80	\$ 43.20
7	Market to Book Ratio		[6] / [12]							1.70	2.03	2.06	2.55
8	Newly Issued Shares		[B] _(t-1) - [B] _t						101.35	6.90	9.75	2.00	6.00
9	Partners Capital per Value Line (millions)		ValueLine					\$ 1,092.9	\$ 988.7	\$ 1,272.5	\$ 1,450.0	\$ 1,600.0	\$ 2,350.0
10	Partners Capital Adjusted to Base Year (millions)		[10] _(t,n) * ([B](6)/[7]) - ([d] _{1k}) _n x(3) _{k(n)} + ([d](4)(2))					\$ 1,092.9	\$ 14.87	\$ 355.7	\$ 647.7	\$ 804.2	\$ 1,155.2
11	Book Value per Unit		[9] / [4]							14.50	14.95	15.95	18.95
12	Adjusted Book Value per Unit		[10] / [4]							\$ 3.29	\$ 5.49	\$ 6.70	\$ 9.17
Buckeye Partners													
1	Earnings per Unit		ValueLine						\$ 2.68	\$ 2.64	\$ 3.00	\$ 3.15	\$ 4.00
2	Cash Flow Per Unit		ValueLine						\$ 3.58	\$ 3.72	\$ 4.20	\$ 4.45	\$ 5.50
3	Distributions per Unit		ValueLine						\$ 2.63	\$ 3.03	\$ 3.23	\$ 3.43	\$ 3.80
4	Units Outstanding (millions)		ValueLine						36.16	38.70	42.00	42.00	42.00
5	Avg Annual P/E Ratio		ValueLine						16.9	16.5	12.0	12.0	12.0
6	Market Value Per Unit		[1] x [5]						\$ 45.46	\$ 43.56	\$ 39.00	\$ 37.80	\$ 48.00
7	Market to Book Ratio		[6] / [12]						2.29	2.14	1.74	1.80	2.24
8	Newly Issued Shares		[B] _(t-1) - [B] _t						3.63	1.54	2.30	0.00	0.00
9	Partners Capital per Value Line (millions)		ValueLine					\$ 605.4	\$ 758.6	\$ 809.6	\$ 870.0	\$ 880.0	\$ 900.0
10	Partners Capital Adjusted to Base Year (millions)		[10] _(t,n) * ([B](6)/[7]) - ([d] _{1k}) _n x(3) _{k(n)} + ([d](4)(2))					\$ 587.1	\$ 704.7	\$ 775.8	\$ 879.6	\$ 930.8	\$ 1,017.7
11	Book Value per Unit		[9] / [4]						17.53	19.88	20.39	20.71	21.43
12	Adjusted Book Value per Unit		[10] / [4]						\$ 18.47	\$ 19.54	\$ 20.94	\$ 22.16	\$ 24.23
Enbridge Energy													
1	Earnings per Unit		ValueLine						\$ 0.77	\$ 3.62			
2	Cash Flow Per Unit		ValueLine						\$ 4.38	\$ 3.19	\$ 5.41		
3	Distributions per Unit		ValueLine						\$ 3.70	\$ 3.70			
4	Units Outstanding (millions)		ValueLine						66.56	77.60			
5	Avg Annual P/E Ratio		ValueLine						67.1	12.7			
6	Market Value Per Unit		[1] x [5]						\$ 51.07	\$ 45.97			
7	Market to Book Ratio		[6] / [12]						2.04	2.48			
8	Newly Issued Shares		[B] _(t-1) - [B] _t						4.97	6.45			
9	Partners Capital per Value Line (millions)		ValueLine					\$ 1,397.9	\$ 1,363.8	\$ 2,043.4			
10	Partners Capital Adjusted to Base Year (millions)		[10] _(t,n) * ([B](6)/[7]) - ([d] _{1k}) _n x(3) _{k(n)} + ([d](4)(2))					\$ 1,436.9	\$ 1,563.5	\$ 2,057.8			
11	Book Value per Unit		[9] / [4]						23.85	20.80			
12	Adjusted Book Value per Unit		[10] / [4]						\$ 23.95	\$ 26.33			

ANALYSIS OF BOOK VALUE PER UNIT FOR THE MLP GROUP

Enterprise Products Partners											
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1 Earnings per Unit	\$ 0.31	\$ 0.82	\$ 1.32	\$ 1.39	\$ 0.54	\$ 0.58	\$ 0.87	\$ 0.91	\$ 1.14	\$ 1.20	\$ 1.45
2 Cash Flow Per Unit	\$ 0.42	\$ 1.08	\$ 1.55	\$ 1.69	\$ 1.11	\$ 1.09	\$ 1.27	\$ 2.16	\$ 2.34	\$ 2.65	\$ 3.15
3 Distributions per Unit	\$ 0.16	\$ 0.90	\$ 1.05	\$ 1.16	\$ 1.33	\$ 1.44	\$ 1.54	\$ 1.66	\$ 1.80	\$ 1.92	\$ 2.06
4 Units Outstanding (millions)	133.93	133.93	168.87	174.21	172.95	216.98	366.77	389.86	432.41	446.00	450.00
5 Avg Annual P/E Ratio	28.2	11.1	8.8	14.7	39.2	37.5	25.9	28.4	22.8	24.0	24.0
6 Market Value Per Unit	\$ 8.74	\$ 9.10	\$ 11.82	\$ 20.43	\$ 21.17	\$ 21.75	\$ 22.53	\$ 25.84	\$ 25.99	\$ 28.80	\$ 34.80
7 Market to Book Ratio	[1] x [5]										
8 Newly Issued Shares	0.00	0.00	0.00	34.94	5.34	-1.26	44.03	151.79	21.09	42.55	13.59
9 Partners Capital per Value Line (millions)	\$ 562.5	\$ 788.5	\$ 936.0	\$ 1,146.9	\$ 1,200.9	\$ 1,706.0	\$ 5,328.8	\$ 5,679.3	\$ 6,480.2	\$ 6,800.0	\$ 7,000.0
10 $[10]_{t-1} + ((8) \times [6]) / [7] - ((4)_{t-1}) \times [3]_{t-1} + ((4) \times [2])$	\$ 562.5	\$ 685.7	\$ 1,020.6	\$ 1,172.8	\$ 1,154.0	\$ 1,506.7	\$ 3,855.9	\$ 4,437.4	\$ 5,439.7	\$ 6,050.5	\$ 6,673.9
11 Book Value per Unit	\$ 4.20	\$ 5.89	\$ 5.64	\$ 6.58	\$ 6.94	\$ 7.86	\$ 14.45	\$ 14.57	\$ 14.99	\$ 15.25	\$ 15.56
12 Adjusted Book Value per Unit	\$ 4.20	\$ 5.12	\$ 6.04	\$ 6.73	\$ 6.87	\$ 6.84	\$ 10.46	\$ 11.38	\$ 12.58	\$ 13.57	\$ 14.83
EOG Resources, Inc.											
1 Earnings per Unit	\$ 0.18	\$ 0.67	\$ 1.62	\$ 1.60	\$ 0.40	\$ 1.83	\$ 2.42	\$ 5.21	\$ 4.83	\$ 4.90	\$ 5.25
2 Cash Flow Per Unit	\$ 1.21	\$ 2.62	\$ 3.23	\$ 3.28	\$ 2.09	\$ 3.44	\$ 4.50	\$ 7.92	\$ 8.44	\$ 9.05	\$ 9.70
3 Distributions per Unit	\$ 0.06	\$ 0.06	\$ 0.07	\$ 0.08	\$ 0.08	\$ 0.09	\$ 0.12	\$ 0.15	\$ 0.24	\$ 0.36	\$ 0.40
4 Units Outstanding (millions)	307.45	249.46	233.81	233.81	229.44	249.46	237.85	242.07	243.74	245.00	247.00
5 Avg Annual P/E Ratio	52.1	14.4	9.6	12.3	47.4	11.2	11.8	10.9	14.3	15.0	15.0
6 Market Value Per Unit	\$ 9.38	\$ 9.65	\$ 15.55	\$ 19.68	\$ 18.66	\$ 20.50	\$ 28.56	\$ 56.79	\$ 69.07	\$ 73.50	\$ 78.75
7 Market to Book Ratio	[1] x [5]										
8 Newly Issued Shares	2.23	2.13	2.63	2.78	2.60	2.30	2.31	3.16	3.01	2.90	2.86
9 Partners Capital per Value Line (millions)	\$ 1,280.3	\$ 1,129.6	\$ 1,380.9	\$ 1,652.7	\$ 1,672.4	\$ 2,223.4	\$ 2,945.4	\$ 4,316.3	\$ 5,599.7	\$ 6,200.0	\$ 6,800.0
10 $[10]_{t-1} + ((8) \times [6]) / [7] - ((4)_{t-1}) \times [3]_{t-1} + ((4) \times [2])$	\$ 1,280.3	\$ 1,652.8	\$ 2,300.7	\$ 3,051.2	\$ 3,480.2	\$ 4,498.4	\$ 5,402.5	\$ 7,366.4	\$ 9,425.6	\$ 11,616.2	\$ 13,979.0
11 Book Value per Unit	\$ 4.16	\$ 4.53	\$ 5.91	\$ 7.07	\$ 7.29	\$ 8.91	\$ 12.38	\$ 17.63	\$ 22.07	\$ 25.31	\$ 27.53
12 Adjusted Book Value per Unit	\$ 4.16	\$ 3.63	\$ 5.84	\$ 13.05	\$ 15.17	\$ 18.03	\$ 22.71	\$ 30.43	\$ 35.67	\$ 47.41	\$ 56.80
Kinder Morgan Energy Partners											
1 Earnings per Unit	\$ 1.05	\$ 1.22	\$ 1.34	\$ 1.56	\$ 1.96	\$ 2.00	\$ 2.22	\$ 2.37	\$ 1.98	\$ 1.70	\$ 2.05
2 Cash Flow Per Unit	\$ 1.30	\$ 1.43	\$ 2.00	\$ 2.38	\$ 2.84	\$ 3.17	\$ 3.52	\$ 3.88	\$ 3.76	\$ 3.85	\$ 4.00
3 Distributions per Unit	\$ 1.19	\$ 1.39	\$ 1.60	\$ 2.08	\$ 2.36	\$ 2.58	\$ 2.81	\$ 3.07	\$ 3.26	\$ 3.44	\$ 3.65
4 Units Outstanding (millions)	97.63	118.27	135.03	165.80	180.91	189.04	207.01	220.24	224.62	235.00	245.00
5 Avg Annual P/E Ratio	16.8	16.1	16.0	21.8	17.0	20.1	20.0	20.7	23.5	16.5	16.5
6 Market Value Per Unit	\$ 17.64	\$ 19.64	\$ 21.44	\$ 34.01	\$ 33.32	\$ 40.20	\$ 44.40	\$ 49.06	\$ 46.53	\$ 28.05	\$ 33.83
7 Market to Book Ratio	[1] x [5]										
8 Newly Issued Shares	1.27	1.31	1.37	1.78	1.76	2.16	2.36	2.99	2.60	1.50	1.74
9 Partners Capital per Value Line (millions)	\$ 1,360.7	\$ 1,774.8	\$ 2,117.1	\$ 3,159.0	\$ 3,415.9	\$ 3,510.9	\$ 3,886.5	\$ 3,613.7	\$ 4,021.7	\$ 4,385.0	\$ 4,770.0
10 $[10]_{t-1} + ((8) \times [6]) / [7] - ((4)_{t-1}) \times [3]_{t-1} + ((4) \times [2])$	\$ 1,360.7	\$ 1,723.4	\$ 2,091.8	\$ 2,856.6	\$ 3,310.9	\$ 3,634.2	\$ 4,213.4	\$ 4,703.3	\$ 4,950.1	\$ 5,316.3	\$ 5,862.8
11 Book Value per Unit	\$ 13.94	\$ 15.01	\$ 15.68	\$ 19.05	\$ 18.88	\$ 18.57	\$ 19.82	\$ 16.41	\$ 17.90	\$ 18.66	\$ 19.47
12 Adjusted Book Value per Unit	\$ 13.94	\$ 14.57	\$ 15.49	\$ 17.23	\$ 18.30	\$ 19.22	\$ 20.35	\$ 21.36	\$ 22.04	\$ 22.62	\$ 23.19

Magellan Midstream Partners LP												
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2012
ValueLine				\$ 0.95	\$ 1.84	\$ 1.66	\$ 1.94	\$ 2.03	\$ 2.24	\$ 2.40	\$ 2.55	\$ 3.00
ValueLine				\$ 1.47	\$ 2.47	\$ 2.28	\$ 2.48	\$ 3.25	\$ 3.82	\$ 3.40	\$ 3.60	\$ 4.30
ValueLine				\$ 1.01	\$ 1.36	\$ 1.53	\$ 1.76	\$ 2.06	\$ 2.34	\$ 2.46	\$ 2.85	\$ 3.35
ValueLine				22.72	54.38	54.39	66.36	66.36	66.36	66.50	66.50	66.50
ValueLine				18.0	9.7	13.3	13.6	15.9	15.6	15.0	15.0	15.0
[1] x [5]				\$ 17.10	\$ 17.85	\$ 22.08	\$ 26.38	\$ 32.28	\$ 34.94	\$ 36.00	\$ 38.25	\$ 45.00
ValueLine				1.73	2.15	2.41	2.22	2.65	2.88	2.90	3.01	3.33
[6] / [12]												
ValueLine				22.72	31.66	0.01	11.97	0.00	0.00	0.14	0.00	0.00
[8] _[t-1] - [8] _[t]				\$ 224.9	\$ 451.8	\$ 498.1	\$ 788.1	\$ 808.0	\$ 806.5	\$ 825.0	\$ 845.0	\$ 900.0
Partners Capital per Value Line (millions)												
[10] _[t-1] * ([8]x[6]/[7]) - ([4] _[t-1]				\$ 224.9	\$ 599.3	\$ 649.5	\$ 873.1	\$ 972.0	\$ 1,088.8	\$ 1,161.4	\$ 1,237.2	\$ 1,346.9
ValueLine				\$ 9.90	\$ 8.31	\$ 9.16	\$ 11.89	\$ 12.18	\$ 12.15	\$ 12.41	\$ 12.71	\$ 13.53
[9] / [4]				\$ 9.90	\$ 11.02	\$ 11.94	\$ 13.16	\$ 14.85	\$ 16.41	\$ 17.46	\$ 18.60	\$ 20.25
[10] / [4]												
Markwest Energy												
ValueLine				\$ 2.42	\$ 0.58	\$ 0.68	\$ 0.66	\$ 0.01	\$ 2.44			
ValueLine				\$ 3.00	\$ 1.24	\$ 1.37	\$ 1.23	\$ 1.37	\$ 3.59			
ValueLine				\$ 0.36	\$ 1.24	\$ 1.49	\$ 1.62	\$ 1.88	\$ 1.88			
ValueLine				8.94	11.63	21.28	25.74	32.37	32.37			
ValueLine				4.5	26.8	31.6	26.8	31.6	9.8			
[1] x [5]				\$ 10.89	\$ 15.54	\$ 20.85	\$ -	\$ 23.91	\$ 23.91			
ValueLine				1.60	2.78	1.84	0.00	1.71	1.71			
[6] / [12]				8.94	2.69	9.65	4.46	6.63	6.63			
[8] _[t-1] - [8] _[t]				\$ 60.9	\$ 65.1	\$ 241.1	\$ 307.2	\$ 452.6				
Partners Capital per Value Line (millions)												
[10] _[t-1] * ([8]x[6]/[7]) - ([4] _[t-1]				\$ 60.9	\$ 87.2	\$ 211.2						
ValueLine				\$ 6.81	\$ 5.60	\$ 11.33	\$ 11.93	\$ 13.98				
[9] / [4]				\$ 6.81	\$ 7.49	\$ 9.93	\$ -	\$ -				
[10] / [4]												
OneOK Partners												
ValueLine				\$ 1.97	\$ 2.70	\$ 2.50	\$ 2.44	\$ (2.27)	\$ 2.81	\$ 2.92	\$ 4.00	
ValueLine				\$ 3.54	\$ 4.56	\$ 4.37	\$ 4.34	\$ 0.20	\$ 4.92	\$ 5.02	\$ 5.94	
ValueLine				\$ 2.30	\$ 2.44	\$ 2.65	\$ 2.89	\$ 3.20	\$ 3.20	\$ 3.20	\$ 3.60	
ValueLine				29.35	29.35	31.50	41.62	43.61	46.40	46.40	82.89	
ValueLine				16.9	11.1	11.2	17.5	15.4	15.4	16.4	13.2	
[1] x [5]				\$ 33.29	\$ 29.97	\$ 28.00	\$ 37.63	\$ 37.59	\$ (34.96)	\$ 47.66	\$ 52.60	
ValueLine				1.93	1.71	1.54	1.71	1.74	-2.03	2.46	2.00	
[6] / [12]				0.00	0.00	2.15	2.19	2.59	0.00	0.00	36.49	
[8] _[t-1] - [8] _[t]				\$ 507.4	\$ 513.3	\$ 572.3	\$ 915.0	\$ 944.0	\$ 800.6	\$ 789.3	\$ 765.6	\$ 2,188.7
Partners Capital per Value Line (millions)												
[10] _[t-1] * ([8]x[6]/[7]) - ([4] _[t-1]				\$ 507.4	\$ 573.7	\$ 678.8	\$ 983.5	\$ 1,096.4	\$ 1,010.1	\$ 1,090.0	\$ 1,174.4	\$ 2,481.8
ValueLine				\$ 17.29	\$ 17.49	\$ 18.17	\$ 21.98	\$ 21.55	\$ 17.25	\$ 17.01	\$ 16.50	\$ 26.40
[9] / [6]				\$ 17.29	\$ 19.55	\$ 21.55	\$ 21.63	\$ 25.03	\$ 21.97	\$ 21.49	\$ 25.30	\$ 28.94
[10] / [6]												
Partners Capital Adjusted to Base Year (millions)												
ValueLine				\$ 17.29	\$ 19.55	\$ 21.55	\$ 21.63	\$ 25.03	\$ 21.97	\$ 21.49	\$ 25.30	\$ 28.94
[9] / [6]												
[10] / [6]												

ANALYSIS OF BOOK VALUE PER UNIT FOR THE MLP GROUP

TEPCO Partners

1	Earnings per Unit		\$ 1.61	\$ 1.91	\$ 1.89	\$ 1.84	\$ 1.79	\$ 1.48	\$ 1.61	\$ 1.71	\$ 1.77	\$ 2.00	\$ 2.10	\$ 2.80
2	Cash Flow Per Unit	ValueLine	\$ 2.52	\$ 3.33	\$ 3.03	\$ 2.88	\$ 3.24	\$ 2.98	\$ 3.40	\$ 3.23	\$ 2.80	\$ 3.85	\$ 4.35	\$ 5.30
3	Distributions per Unit	ValueLine	\$ 1.75	\$ 1.85	\$ 2.00	\$ 2.15	\$ 2.35	\$ 2.50	\$ 2.64	\$ 2.68	\$ 2.70	\$ 2.74	\$ 2.88	\$ 3.15
4	Units Outstanding (millions)	ValueLine	\$ 29.66	\$ 29.00	\$ 32.70	\$ 40.45	\$ 53.81	\$ 63.00	\$ 63.00	\$ 69.96	\$ 89.80	\$ 92.00	\$ 94.00	\$ 98.00
5	Avg Annual P/E Ratio	ValueLine	17.1	12.4	12.2	16.0	16.8	23.6	24.3	23.7	21.1	16.0	16.0	16.0
6	Market Value Per Unit	[11] x [5]	\$ 27.53	\$ 23.68	\$ 23.06	\$ 29.44	\$ 30.07	\$ 34.46	\$ 39.12	\$ 40.53	\$ 37.35	\$ 32.00	\$ 33.60	\$ 44.80
7	Market to Book Ratio	[6] / [12]	3.59	2.99	2.39	2.19	1.81	1.96	2.41	2.36	2.54	2.03	2.04	2.25
8	Newly Issued Shares	[8] _{t-1} - [8] _t	0.00	-0.66	3.70	7.75	13.38	9.19	0.00	6.96	19.84	2.20	2.00	4.00
9	Partners Capital per Value Line (millions)	ValueLine	\$ 227.2	\$ 229.8	\$ 315.1	\$ 543.2	\$ 891.8	\$ 1,109.3	\$ 1,021.4	\$ 1,201.4	\$ 1,320.3	\$ 1,450.0	\$ 1,550.0	\$ 1,950.0
10	Partners Capital Adjusted to Base Year (millions)	[10] _{t-1} + ([8]x[6]/[7]) - ([4] _t)	\$ 227.2	\$ 266.6	\$ 347.7	\$ 502.9	\$ 811.7	\$ 1,034.8	\$ 1,091.5	\$ 1,270.7	\$ 1,608.3	\$ 1,754.8	\$ 1,944.6	\$ 2,272.8
11	Book Value per Unit	[9] / [4]	\$ 7.66	\$ 7.92	\$ 9.64	\$ 13.43	\$ 16.57	\$ 17.61	\$ 16.21	\$ 17.17	\$ 14.70	\$ 15.76	\$ 16.49	\$ 19.90
12	Adjusted Book Value per Unit	[10] / [4]	\$ 7.66	\$ 9.19	\$ 10.63	\$ 12.43	\$ 15.08	\$ 18.43	\$ 17.33	\$ 18.16	\$ 17.91	\$ 19.07	\$ 20.69	\$ 23.19

(a) P/E Ratio for 2006 and 2007 were not available and were estimated by taking the Value Line projected P/E for 2009-2011.

(b) Assume 0 shares issued in 1998

(c) Assume base year is 1998

Distribution Coverage Ratios

BOARDWALK PIPELINE PARTNERS

	2007	2008	2009
Revenues	\$ 632.1	\$ 647.9	\$ 664.1
Other Operating Items:			
Costs and Operating	\$ (165.5)	\$ (169.6)	\$ (173.9)
Depreciation	(105.1)	(168.9)	(201.1)
SG&A	(104.3)	(107.5)	(110.8)
Other Costs	(30.1)	(28.1)	(27.9)
Total Other Operating Items	\$ (405.0)	\$ (474.1)	\$ (513.7)
Other Income Adjustments	\$ 41.3	\$ 213.8	\$ 446.5
Operating Income	268.4	387.6	596.9
EBITDA	\$ 373.5	\$ 556.5	\$ 798.0
Other Income (Expenses)			
Interest, net	\$ (77.6)	\$ (103.9)	\$ (128.5)
Other	10.9	8.0	8.0
Total Other Income (Expense)	\$ (66.7)	\$ (95.9)	\$ (120.5)
Pretax Income	\$ 201.7	\$ 291.7	\$ 476.4
Income Tax	(0.2)	-	-
Minority Interest	-	-	-
Reported Net Income from Continuing Operations	\$ 201.5	\$ 291.7	\$ 476.4
Extraordinary Items/Discontinued Operations	-	-	-
Income to General Partner	(8.8)	(40.0)	(113.3)
Reported Net Income to Common Units	\$ 192.7	\$ 251.7	\$ 363.1
Non-recurring Items	\$ 2.6	\$ -	\$ -
Operating Earnings to Common	\$ 195.3	\$ 251.7	\$ 363.1
Average units outstanding - Basic	114.5	127.7	132.1
Average units outstanding - Diluted	114.5	127.7	132.1
Earnings per Unit			
Reported EPU - Basic	\$ 1.68	\$ 1.97	\$ 2.75
Reported EPU - Diluted	\$ 1.68	\$ 1.97	\$ 2.75
Operating EPU - Diluted	\$ 1.71	\$ 1.97	\$ 2.75
Distributable Cash Flow			
Recurring Net Income to Common	\$ 195.3	\$ 251.7	\$ 363.1
Depreciation	105.1	168.9	201.1
Other	0.8	2.8	11.1
Maintenance Capital Spending	(51.4)	(60.0)	(88.9)
Total Distributable Cash Flow	\$ 249.8	\$ 363.4	\$ 486.4
Distributable Cash Flow per Unit - Diluted	\$ 2.18	\$ 2.85	\$ 3.68
Ratios and other items			
Distribution per Unit	\$ 1.86	\$ 2.33	\$ 2.83
Total Unit Coverage	1.2	1.2	1.3
Distribution Pay Out	85.3%	81.9%	76.9%
Total Debt to Capital	54%	57%	52%
Estimated Yield	5.53%	5.91%	5.15%
Implied Price	\$ 33.66	\$ 39.42	\$ 54.97
Exp. P/E Ratio	20.00	20.00	20.00

Source: Value Line

Adjusted Yield (incl. payments to GP)	5.75%	6.71%	6.71%
Assumed ROE	15.50%	15.50%	15.50%
Retention Ratio	14.74%	18.12%	23.14%
Estimated Growth	2.29%	2.81%	3.59%
DCF	8.04%	9.51%	10.29%

Source: Value Line

Distribution Coverage Ratios

ENBRIDGE ENERGY PARTNERS

	2007	2008	2009
Revenues	\$ 8,717.1	\$ 11,142.3	\$ 12,151.1
Other Operating Items:			
Costs and Operating	\$ (597.8)	\$ (711.2)	\$ (817.2)
Depreciation	(155.9)	(202.3)	(232.9)
SG&A	(7,645.1)	(9,831.0)	(10,634.3)
Other Costs	-	-	-
Total Other Operating Items	\$ (8,398.8)	\$ (10,744.5)	\$ (11,684.4)
Other Income Adjustments	\$ -	\$ -	\$ -
Operating Income	318.3	397.8	466.7
EBITDA	\$ 162.4	\$ 195.5	\$ 233.8
Other Income (Expenses)			
Interest, net	\$ (109.6)	\$ (148.1)	\$ (196.4)
Other	6.9	7.0	6.9
Total Other Income (Expense)	\$ (102.7)	\$ (141.1)	\$ (189.5)
Pretax Income	\$ 215.6	\$ 256.7	\$ 277.2
Income Tax	(2.6)	(2.0)	(2.0)
Minority Interest	-	-	-
Reported Net Income from Continuing Operations	\$ 213.0	\$ 254.7	\$ 275.2
Extraordinary Items/Discontinued Operations	-	-	-
Income to General Partner	(30.1)	(33.7)	(41.9)
Reported Net Income to Common Units	\$ 182.9	\$ 221.0	\$ 233.3
Non-recurring Items	\$ 16.3	\$ -	\$ -
Operating Earnings to Common	\$ 199.2	\$ 221.0	\$ 233.3
Average units outstanding - Basic	79.5	92.5	105.3
Average units outstanding - Diluted	79.5	92.5	105.3
Earnings per Unit			
Reported EPU - Basic	\$ 2.30	\$ 2.39	\$ 2.22
Reported EPU - Diluted	\$ 2.30	\$ 2.39	\$ 2.22
Operating EPU - Diluted	\$ 2.51	\$ 2.39	\$ 2.22
Distributable Cash Flow			
Recurring Net Income to Common	\$ 199.2	\$ 221.0	\$ 233.3
Depreciation	155.9	202.3	232.9
Other	(3.2)	(6.7)	(5.9)
Maintenance Capital Spending	(57.8)	(66.0)	(77.0)
Total Distributable Cash Flow	\$ 294.1	\$ 350.6	\$ 383.3
Distributable Cash Flow per Unit - Diluted	\$ 3.70	\$ 3.79	\$ 3.64
Ratios and other items			
Distribution per Unit	\$ 3.70	\$ 3.75	\$ 3.80
Total Unit Coverage	1.0	1.0	1.0
Distribution Pay Out	100.0%	98.9%	104.4%
Total Debt to Capital	55%	57%	52%
Estimated Yield	8.04%	7.85%	8.58%
Implied Price	\$ 46.01	\$ 47.78	\$ 44.31
Price/EBITDA	20.00	20.00	20.00

Source: Value Line

Adjusted Yield (incl. payments to GP)	8.86%	8.61%	9.47%
Assumed ROE	13.90%	13.90%	13.90%
Retention Ratio	-0.02%	1.06%	-4.39%
Estimated Growth	0.00%	0.15%	0.00%
DCF	8.86%	8.76%	9.47%

Source: Value Line

Distribution Coverage Ratios

KINDER MORGAN ENERGY PARTNERS

	2006	2007	2008
Revenues	\$ 8,954.6	\$ 11,199.6	\$ 15,365.5
Other Operating Items:			
Costs and Operating	\$ (6,976.7)	\$ (9,008.5)	\$ (12,718.3)
Depreciation	(413.7)	(499.0)	(642.5)
SG&A	(219.6)	(220.4)	(221.7)
Other Costs	(118.8)	(112.0)	(153.7)
Total Other Operating Items	\$ (7,728.8)	\$ (9,839.9)	\$ (13,736.2)
Other Income Adjustments	\$ 100.8	\$ 56.1	\$ 56.1
Operating Income	1,326.6	1,415.8	1,685.4
EBITDA	\$ 1,740.3	\$ 1,914.8	\$ 2,327.9
Other Income (Expenses)			
Interest, net	\$ (331.5)	\$ (253.2)	\$ (305.6)
Other	-	-	-
Total Other Income (Expense)	\$ (331.5)	\$ (253.2)	\$ (305.6)
Pretax Income	\$ 995.1	\$ 1,162.6	\$ 1,379.8
Income Tax	(19.0)	(28.7)	(31.1)
Minority Interest	(15.0)	(13.0)	(15.3)
Reported Net Income from Continuing Operations	\$ 961.1	\$ 1,120.9	\$ 1,333.4
Extraordinary Items/Discontinued Operations	-	-	-
Income to General Partner	(513.0)	(560.4)	(666.8)
Reported Net Income to Common Units	\$ 448.1	\$ 560.5	\$ 666.6
Non-recurring Items	\$ 8.6	\$ -	\$ -
Operating Earnings to Common	\$ 456.7	\$ 560.5	\$ 666.6
Average units outstanding - Basic	224.8	238.7	261.2
Average units outstanding - Diluted	224.8	238.7	261.2
Earnings per Unit			
Reported EPU - Basic	\$ 1.99	\$ 2.35	\$ 2.55
Reported EPU - Diluted	\$ 1.99	\$ 2.35	\$ 2.55
Operating EPU - Diluted	\$ 2.03	\$ 2.35	\$ 2.55
Distributable Cash Flow			
Recurring Net Income to Common	\$ 456.7	\$ 560.5	\$ 666.6
Depreciation	413.7	499.0	642.5
Other	(4.2)	(39.2)	(34.7)
Maintenance Capital Spending	(125.5)	(150.0)	(170.0)
Total Distributable Cash Flow	\$ 740.7	\$ 870.3	\$ 1,104.4
Distributable Cash Flow per Unit - Diluted	\$ 3.29	\$ 3.65	\$ 4.23
Ratios and other items			
Distribution per Unit	\$ 3.26	\$ 3.44	\$ 3.80
Total Unit Coverage	1.0	1.1	1.1
Distribution Pay Out	98.9%	94.3%	89.9%
Total Debt to Capital	52%	55%	52%
Estimated Yield	8.18%	7.32%	7.44%
Implied Price	\$ 39.87	\$ 46.96	\$ 51.04
Price/EBITDA	20.00	20.00	20.00

Source: Value Line

Distribution Yield	8.18%	7.32%	7.44%
Assumed ROE	7.90%	6.90%	9.40%
Retention Ratio	1.06%	5.65%	10.13%
Estimated Growth	0.08%	0.39%	0.95%
DCF	8.26%	7.71%	8.40%

Source: RBC

CASH FLOWS FROM OPERATIONS VERSUS CAPITAL EXPENDITURES, DIVIDENDS AND DISTRIBUTIONS

	EQUITABLE RESOURCES			NATIONAL FUEL GAS			QUESTAR			AVERAGE
	2006	2005	2004	2006	2005	2004	2006	2005	2004	
Cash Flows from Operations	\$ 619.3	\$ (312.0)	\$ 180.0	\$ 471.1	\$ 317.3	\$ 437.1	\$ 966.2	\$ 695.1	\$ 585.7	
Capital Expenditures	(404.5)	(275.8)	(201.8)	(294.2)	(219.5)	(172.3)	(916.1)	(712.7)	(446.5)	
Other Investing Activities	(3.2)	623.6	43.3	13.0	116.1	9.2	33.4	19.2	7.2	
Total Investing Activities	\$ (407.7)	\$ 347.8	\$ (158.5)	\$ (281.2)	\$ (103.4)	\$ (163.1)	\$ (882.7)	\$ (693.5)	\$ (439.3)	
Dividends and Repurchases - Common Stock	\$ (104.9)	\$ (222.2)	\$ (207.9)	\$ (183.5)	\$ (84.2)	\$ (89.1)	\$ (85.9)	\$ (85.3)	\$ (76.2)	
Other Cash Flows from Financing Activities	(181.7)	234.8	102.2	39.6	(121.1)	(180.7)	13.6	101.5	(80.4)	
Total Financing Activities	\$ (286.6)	\$ 12.6	\$ (105.7)	\$ (143.9)	\$ (215.3)	\$ (269.8)	\$ (72.3)	\$ 16.2	\$ (156.6)	
Net Cash Flow (Operations, Investing, Financing)	\$ (75.0)	\$ 48.4	\$ (84.2)	\$ 46.0	\$ (1.4)	\$ 4.2	\$ 11.2	\$ 17.8	\$ (10.2)	
Cash Flows from Operations less CAPEX and Dividends	\$ 109.9	\$ (810.0)	\$ (229.7)	\$ (6.6)	\$ 3.6	\$ 175.7	\$ (35.8)	\$ (102.9)	\$ 63.0	
Capital Expenditures and Dividends/Cash Flows from Operations	-82.25%	159.62%	-227.61%	-101.40%	-98.87%	-59.80%	-103.71%	-114.80%	-89.24%	-109.71% [1]

Source: SEC Forms 10-K

[1] Excludes Equitable Resources 2005 data due to negative operating cash flows

Internal Growth Rate of Corporations					
	Questar	Equitable	National Fuel Gas	Williams Companies	Average
2006 Earnings	\$ 5.07	\$ 1.77	\$ 1.61	\$ 0.55	
2006 Dividends	\$ 0.93	\$ 0.87	\$ 1.18	\$ 0.35	
Payout Ratio	18.34%	49.15%	73.29%	62.73%	50.88%
2005 Earnings	\$ 3.74	\$ 2.09	\$ 2.23	\$ 0.53	
2005 Dividends	\$ 0.89	\$ 0.82	\$ 1.40	\$ 0.25	
Payout Ratio	23.80%	39.23%	62.78%	47.17%	43.25%
2004 Earnings	\$ 2.67	\$ 2.37	\$ 2.01	\$ 0.18	
2004 Dividends Paid	\$ 0.85	\$ 0.72	\$ 1.10	\$ 0.08	
Payout Ratio	31.84%	30.38%	54.73%	44.44%	40.35%
Average Payout Ratio	24.66%	39.59%	63.60%	51.45%	44.82%
Average Retention Ratio	75.34%	60.41%	36.40%	48.55%	55.18%
DCF Result	8.56%	10.41%	8.05%	10.93%	9.49%
Internal Growth Rate	6.45%	6.29%	2.93%	5.31%	5.24%
I/B/E/S Growth Rate	8.50%	10.00%	5.00%	11.50%	8.75%
Difference	2.05%	3.71%	2.07%	6.19%	3.51%

QUESTAR CORPORATION TWO-STAGE CONSTANT GROWTH DCF								
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]

Notes

- [1] Source: Yahoo! Finance
- [2] Source: Yahoo! Finance.
- [3] Equals Col. [1]/Col. [2]
- [4] Equals Col. [3] x (1+(.5 x Col. [7]))
- [5] Source: Thomson Research
- [6] Average of EIA AEO, and Blue Chip Forecast
- [7] Equals Col [5] x (2/3)+ Col [6] x (1/3)
- [8] Equals Col. [4] + Col. [7]

EQUITABLE TWO-STAGE CONSTANT GROWTH DCF								
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
				Expected	I/B/E/S		Weighted	
	Annualized	Average	Dividend	Dividend	Consensus		Average	
	Dividend	Stock Price	Yield	Yield	Growth	GDP Growth	Growth	DCF
Company								
Equitable	\$0.88	\$47.14	1.87%	1.96%	10.00%	5.36%	8.45%	10.41%
	EQT							

Notes

- [1] Source: Yahoo! Finance
- [2] Source: Yahoo! Finance.
- [3] Equals Col. [1]/Col. [2]
- [4] Equals Col. [3] x (1+.5 x Col. [7])
- [5] Source: Thomson Research
- [6] Average of EIA AEO, and Blue Chip Forecast
- [7] Equals Col [5] x (2/3)+ Col [6] x (1/3)
- [8] Equals Col. [4] + Col. [7]

NATIONAL FUEL GAS TWO-STAGE CONSTANT GROWTH DCF								
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	I/B/E/S Consensus Growth	GDP Growth	Weighted Average Growth Rate	DCF
National Fuel Gas	\$1.24	\$43.39	2.86%	2.93%	5.00%	5.36%	5.12%	8.05%
	NFG							

Notes

- [1] Source: Yahoo! Finance
- [2] Source: Yahoo! Finance.
- [3] Equals Col. [1]/Col. [2]
- [4] Equals Col. [3] x (1+.5 x Col. [7])
- [5] Source: Thomson Research
- [6] Average of EIA AEO, and Blue Chip Forecast
- [7] Equals Col [5] x (2/3)+ Col [6] x (1/3)
- [8] Equals Col. [4] + Col. [7]

ANALYSIS OF TAXABLE INCOME UNDER CORPORATE SCENARIO AND MLP SCENARIO

ASSUMPTIONS

Purchase at end of Y0 of 1 unit/share	\$ 100.00
Sale in Y4 of 1 unit/share for \$200	\$ 200.00
Growth	0%
Distributions	\$ 20.00
Net Income	\$ 5.00
Payout Ratio	100%

CORPORATION SCENARIO						Taxable Total		
	Y0	Y1	Y2	Y3	Y4			
Basis in Share of Stock	\$ 100.00	\$ 100.00	\$ 100.00	\$ 100.00	\$ 100.00		Unit Selling Price	\$ 200.00
Dividend		\$ 5.00	\$ 5.00	\$ 5.00	\$ 5.00	\$ 20.00	Dividends Received	\$ 20.00
Capital Gain					\$ 100.00	\$ 100.00	Less: Basis	\$ (100.00)
Taxable to S/H, corporation	\$ -	\$ 5.00	\$ 5.00	\$ 5.00	\$ 105.00	\$ 120.00	Taxable Amount	\$ 120.00

MLP SCENARIO						Taxable Total		
	Y0	Y1	Y2	Y3	Y4			
Basis in Partnership Unit	\$ 100.00	\$ 85.00	\$ 70.00	\$ 55.00	\$ 40.00		Unit Selling Price	\$ 200.00
Distribution		\$ 20.00	\$ 20.00	\$ 20.00	\$ 20.00		Distributions Received	\$ 80.00
Partnership Income	\$ -	\$ 5.00	\$ 5.00	\$ 5.00	\$ 5.00	\$ 20.00	Less: Basis	\$ (100.00)
Capital Gain					\$ 160.00	\$ 160.00		
Taxable to MLP Unit Holder		\$ 5.00	\$ 5.00	\$ 5.00	\$ 165.00	\$ 180.00	Taxable Amount	\$ 180.00

PROXY GROUP GROWTH RATES AND YIELDS							
MLP Growth Rates and Yields							
	Ticker	Valueline		I/B/E/S	Yahoo		Mean
		EPS			First Call	Growth Rate	
Boardwalk Pipeline Partners LP	BWP	-		7.0%	7.1%	7.1%	4.86%
Enbridge Energy Partners LP	EEP	-		5.0%	4.7%	4.9%	6.74%
Enterprise Products Partners LP	EPD	11.0%		8.0%	8.50%	9.2%	6.13%
Kinder Morgan Energy Partners, L.P.	KMP	6.0%		7.0%	6.50%	6.5%	6.30%
MarkWest Energy Partners, L.P.	MWE	-		6.2%	6.20%	6.2%	6.07%
OneOK Partners, L.P.	OKS	-		5.5%	6.0%	5.8%	5.91%
Mean		8.5%		6.5%	6.5%	6.6%	6.0%
Median		8.5%		6.6%	6.4%	6.4%	6.1%

Corporate Growth Rates and Yields							
Company	Ticker	Valueline		I/B/E/S	Yahoo		Mean
		EPS			First Call	Growth Rate	
Williams Companies	WMB	18.5%		11.5%	13.33%	14.4%	1.40%

Monthly High and Low Stock Prices⁽¹⁾
For Proxy Companies

Dates	Boardwalk Pipeline Partners LP			Enbridge Energy Partners LP			El Paso Corp			Enterprise Products Partners LP			Equitable Resources, Inc.			Kinder Morgan Energy Partners, LP			MidWest Energy Partners, LP		
	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg
1-Jun-07	\$ 35.50	\$ 33.98	\$ 34.74	\$ 56.01	\$ 53.32	\$ 54.67	\$ 17.23	\$ 16.50	\$ 16.87	\$ 31.94	\$ 30.36	\$ 31.15	\$ 53.51	\$ 48.84	\$ 51.18	\$ 55.63	\$ 52.76	\$ 54.20	\$ 35.49	\$ 33.95	\$ 34.72
1-May-07	\$ 36.27	\$ 33.38	\$ 34.83	\$ 60.39	\$ 54.66	\$ 57.53	\$ 17.04	\$ 14.95	\$ 16.00	\$ 32.88	\$ 30.50	\$ 31.69	\$ 52.36	\$ 50.29	\$ 51.33	\$ 56.65	\$ 54.08	\$ 55.37	\$ 36.58	\$ 33.80	\$ 35.19
1-Apr-07	\$ 36.96	\$ 36.59	\$ 36.78	\$ 61.82	\$ 56.29	\$ 59.06	\$ 15.52	\$ 14.66	\$ 15.09	\$ 33.15	\$ 31.75	\$ 32.45	\$ 52.82	\$ 48.46	\$ 50.64	\$ 56.96	\$ 52.79	\$ 54.88	\$ 37.50	\$ 34.00	\$ 35.75
1-Mar-07	\$ 38.50	\$ 35.97	\$ 37.24	\$ 66.05	\$ 52.51	\$ 54.28	\$ 14.76	\$ 13.76	\$ 14.26	\$ 32.60	\$ 30.19	\$ 31.40	\$ 48.52	\$ 41.19	\$ 44.91	\$ 53.36	\$ 50.35	\$ 51.86	\$ 35.75	\$ 32.98	\$ 34.37
1-Feb-07	\$ 36.74	\$ 34.90	\$ 35.82	\$ 53.33	\$ 52.41	\$ 52.87	\$ 15.60	\$ 14.35	\$ 14.98	\$ 30.59	\$ 29.58	\$ 30.09	\$ 44.26	\$ 42.35	\$ 43.31	\$ 51.65	\$ 50.24	\$ 50.95	\$ 32.47	\$ 30.56	\$ 31.52
1-Jan-07	\$ 35.36	\$ 30.55	\$ 32.96	\$ 52.91	\$ 48.68	\$ 50.80	\$ 15.56	\$ 14.42	\$ 14.99	\$ 29.80	\$ 28.46	\$ 29.13	\$ 43.36	\$ 39.67	\$ 41.52	\$ 50.72	\$ 47.46	\$ 49.09	\$ 31.38	\$ 28.78	\$ 30.08
Average Price ⁽²⁾	\$	\$	\$ 35.39	\$	\$	\$ 54.87	\$	\$	\$ 15.36	\$	\$	\$ 30.98	\$	\$	\$ 47.14	\$	\$	\$ 52.72	\$	\$	\$ 33.60

Dates	National Fuel Gas Company			OneOK, Inc			Williams Companies			10-Year Treasury			10-Yr TIPS			Spread		
	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg
1-Jun-07	\$ 46.51	\$ 42.91	\$ 44.71	\$ 70.70	\$ 67.42	\$ 69.06	\$ 32.43	\$ 29.71	\$ 31.07	\$ 5.25	\$ 4.93	\$ 5.09	\$ 2.83	\$ 2.55	\$ 2.69	\$ 2.42	\$ 2.38	\$ 2.40
1-May-07	\$ 47.49	\$ 45.21	\$ 46.35	\$ 72.42	\$ 66.82	\$ 69.62	\$ 32.19	\$ 28.25	\$ 30.22	\$ 4.89	\$ 4.63	\$ 4.76	\$ 2.54	\$ 2.19	\$ 2.37	\$ 2.48	\$ 2.33	\$ 2.41
1-Apr-07	\$ 47.76	\$ 44.14	\$ 45.95	\$ 71.11	\$ 67.60	\$ 69.36	\$ 30.21	\$ 28.20	\$ 29.21	\$ 4.76	\$ 4.62	\$ 4.69	\$ 2.51	\$ 2.21	\$ 2.26	\$ 2.52	\$ 2.36	\$ 2.44
1-Mar-07	\$ 43.54	\$ 40.90	\$ 42.22	\$ 67.60	\$ 64.00	\$ 65.80	\$ 28.94	\$ 25.88	\$ 27.46	\$ 4.66	\$ 4.49	\$ 4.58	\$ 2.25	\$ 2.14	\$ 2.20	\$ 2.49	\$ 2.27	\$ 2.38
1-Feb-07	\$ 43.21	\$ 40.89	\$ 39.08	\$ 66.00	\$ 63.75	\$ 64.88	\$ 28.33	\$ 26.94	\$ 27.64	\$ 4.81	\$ 4.51	\$ 4.66	\$ 2.46	\$ 2.14	\$ 2.30	\$ 2.41	\$ 2.16	\$ 2.29
1-Jan-07	\$ 40.89	\$ 37.26	\$ 39.08	\$ 64.15	\$ 62.62	\$ 63.39	\$ 27.15	\$ 25.32	\$ 26.24	\$ 4.89	\$ 4.66	\$ 4.78	\$ 2.50	\$ 2.38	\$ 2.44	\$ 2.44	\$ 2.26	\$ 2.35
Average Price	\$	\$	\$ 43.39	\$	\$	\$ 67.03	\$	\$	\$ 28.64	\$	\$	\$ 4.76	\$	\$	\$ 2.38	\$	\$	\$ 2.38

Notes

- [1] Stock prices through 6/30/2007
[2] FERC averaging convention

[illegible]

Notes

[1] Source: Yahoo! Finance
 [2] Source: Yahoo! Finance.
 [3] Equals Col. [1]/Col. [2]
 [4] Equals Col. [1] x (1+.5 x Col. [7])]/Col. [2]
 [5] Source: Thomson Research
 [6] Average of EIA AEO, and Blue Chip Forecast
 [7] Equals Col. [9] x (2/3)+ Col. [10] x (1/3)
 [8] Equals Col. [4] + Col. [11]

180 DAY PROXY GROUP TWO-STAGE CONSTANT GROWTH DCF

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Consensus Growth (Thomson)	GDP Growth	Weighted Average Growth Rate *	DCF
PROXY GROUP NATURAL GAS TRANSPORTATION COMPANIES								
Boardwalk Pipeline Partners LP	\$1.72	\$34.34	5.01%	5.18%	7.00%	5.36%	6.45%	11.64%
Enbridge Energy Partners LP	\$3.70	\$53.91	6.86%	7.03%	5.00%	5.36%	5.12%	12.16%
Enterprise Products Partners LP	\$1.90	\$30.57	6.22%	6.46%	8.00%	5.36%	7.12%	13.59%
Kinder Morgan Energy Partners, L.P.	\$3.32	\$51.83	6.41%	6.63%	7.00%	5.36%	6.45%	13.08%
MarkWest Energy Partners, L.P.	\$2.04	\$32.47	6.28%	6.48%	6.20%	5.36%	5.92%	12.40%
OneOK Partners, L.P.	\$3.96	\$66.21	5.98%	6.15%	5.50%	5.36%	5.45%	11.60%
Williams Companies	\$0.40	\$28.51	1.40%	1.48%	11.50%	5.36%	9.45%	10.94%
		MEAN OF MIDPOINTS		5.63%	7.17%		6.57%	12.20%
		MEDIAN OF MIDPOINTS		6.46%	7.00%		6.45%	12.16%

Notes

- [1] Source: Yahoo! Finance
[2] Source: Yahoo! Finance.
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [1] x (1+ (.5 x Col. [7]))/Col. [2]
[5] Source: Thomson Research
[6] Average of EIA AEO, and Blue Chip Forecast
[7] Equals Col [9] x (2/3)+ Col [10] x (1/3)
[8] Equals Col. [4] + Col. [11]

ZONE OF REASONABLENESS HIGH
ZONE OF REASONABLENESS LOW
ZONE OF REASONABLENESS MIDPOINT

RISK PREMIUM ANALYSIS (10 YR TREASURY VERSUS FERC AUTHORIZED ROES IN CONTESTED CASES)

	10 Year Treasury ^TNX	FERC Authorized ROEs ROES	Risk Premium vs Treasurys	Calculated Risk Premium Vs Treasurys using regression equation [0.11 + (Tyield x - 0.68105)]
Nov-73	6.69%	12.00%	5.31%	5.95%
Oct-76	7.42%	13.00%	5.58%	5.45%
Feb-77	7.45%	15.95%	8.50%	5.43%
Jul-77	7.42%	12.80%	5.38%	5.45%
Jan-78	7.94%	12.50%	4.56%	5.10%
May-79	9.06%	11.50%	2.44%	4.33%
Jan-80	11.13%	12.50%	1.37%	2.92%
Feb-80	12.72%	15.30%	2.58%	1.84%
Apr-80	10.76%	11.00%	0.24%	3.18%
Aug-80	11.55%	15.00%	3.45%	2.64%
Aug-81	15.41%	16.50%	1.09%	0.01%
Jan-82	14.14%	15.30%	1.16%	0.87%
Jun-82	14.44%	14.70%	0.26%	0.67%
Jan-83	10.80%	14.00%	3.20%	3.15%
Mar-83	10.62%	14.64%	4.02%	3.27%
Jan-85	11.17%	14.25%	3.08%	2.90%
Nov-90	8.26%	12.60%	4.34%	4.88%
Sep-92	6.37%	14.45%	8.08%	6.17%
Nov-93	5.80%	13.46%	7.66%	6.55%
Sep-95	6.16%	12.49%	6.33%	6.31%
Jan-96	5.58%	12.36%	6.78%	6.70%
Feb-96	6.11%	12.22%	6.11%	6.34%
Aug-96	6.94%	12.25%	5.31%	5.78%
Jan-97	6.50%	12.38%	5.88%	6.08%
May-97	6.66%	12.40%	5.74%	5.97%
Jun-97	6.50%	13.67%	7.17%	6.08%
Jan-00	6.67%	12.48%	5.81%	5.96%
Mar-00	6.02%	11.83%	5.81%	6.40%
Jul-03	4.47%	11.22%	6.75%	7.46%
Oct-06	4.61%	11.20%	6.59%	7.36%

Mar-07 10 Yr Treasury			5.20%
Treasurys			
<u>Upper and Lower Bound based on 1 x Standard Error of Each Variable</u>			
upper	7.98%	13.18%	
Model calc	6.96%	12.16%	
lower	5.95%	11.15%	

<u>Upper and Lower Bound of Equation based on 1 x Standard Error</u>			
upper	8.11%	13.31%	
Model calc	6.96%	12.16%	
lower	5.81%	11.01%	

<u>Upper and Lower Bound of Equation based on 2 x Standard Error</u>			
upper	9.27%	14.47%	
Model calc	6.96%	12.16%	
lower	4.66%	9.86%	

<u>Overall Maximum and Minimum Risk Premium of All Observations</u>			
minimum	5.31%	10.51%	
maximum	5.31%	10.51%	

Regression Statistics	
Multiple R	0.878547478
R Square	0.771845671
Adjusted R S	0.76339551
Standard Err	0.011514166
Observations	29

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.012109619	0.012109619	91.34094965	3.71735E-10
Residual	27	0.003579552	0.000132576		
Total	28	0.015689172			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.105046107	0.006473948	16.22597238	1.89343E-15	0.091762663	0.118329552	0.091762663	0.11833
0.0669	-0.681050794	0.071260152	-9.557245924	3.71735E-10	-0.827264546	-0.534837042	-0.827264546	-0.534837

RESIDUAL OUTPUT

Observation	Predicted 0.0531	Residuals
1	0.054512138	0.001287862
2	0.054307823	0.030692177
3	0.054512138	-0.000712138
4	0.050970674	-0.005370674
5	0.043342905	-0.018942905
6	0.029245154	-0.015545154
7	0.018416446	0.007383554
8	0.031765042	-0.029365042
9	0.026384741	0.008115259
10	9.618E-05	0.01080382
11	0.008745525	0.002854475
12	0.006702373	-0.004102373
13	0.031492622	0.000507378
14	0.032718513	0.007481487
15	0.028972734	0.001827266
16	0.048791312	-0.005391312
17	0.061663172	0.019136828
18	0.065545161	0.011054839
19	0.063093378	0.000206622
20	0.067043473	0.000756527
21	0.063433904	-0.002333904
22	0.057781182	-0.004681182
23	0.060777806	-0.001977806
24	0.059688125	-0.002288125
25	0.060777806	0.010922194
26	0.059620019	-0.001520019
27	0.06404685	-0.00594685
28	0.074803137	-0.007103137
29	0.073649666	-0.007749666