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Gas Transmission

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December 12, 2003

Ms. Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Algonquin Gas Transmission Company, Docket No. RP04-24-___
Submittal of Statement P Testimony

Dear Ms. Salas:

In compliance with the November 7 Order[1] and the November 21 extension notice issued in the captioned docket, Algonquin Gas Transmission Company ("Algonquin") hereby submits Statement P, Testimony, to be included with and become a part of its November 26 filing in this proceeding.

On November 26, 2003, Algonquin submitted tariff sheets and supporting statements and schedules in compliance with an order issued by the Commission on November 7, 2003 in the captioned docket. Pursuant to a Commission notice issued on November 21, 2003, which extended the date by which Algonquin must file Statement P until December 12, 2003, the November 26 filing did not include Statement P. The Statement P submitted in this filing consists of the testimony and corresponding affidavits of the following witnesses:

(1) **Richard J. Kruse** – Overview of pipeline system, services at issue, and summary of proposed tariff revisions;

(2) **Gregg E. McBride** – Cost of service allocation, rate design and billing determinants;

(3) **Sabra L. Harrington** – Books and records; and

(4) **J. Peter Williamson** – Capital structure, cost of debt, and rate of return on equity.

In accordance with Section 154.208 of the Commission's regulations, copies of this filing are being mailed or, if requested, transmitted by email to all affected customers of Algonquin and interested state commissions, and to all parties on the Commission's official service list in this proceeding.

[1] *Algonquin Gas Transmission Co.*, 105 FERC ¶ 61,180 (2003) ("November 7 Order").

Please do not hesitate to contact the undersigned at (713) 627-5215 with any questions regarding this filing.

Respectfully submitted,

/s/ Steven E. Hellman

Steven E. Hellman
Assistant General Counsel

Enclosures

cc: Robert R. Sheldon (FERC)
Jason M. Stanek (FERC)

EXHIBIT NO. ___(RJK-1)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Algonquin Gas Transmission Company	§ § §	Docket No. RP04-24

PREPARED DIRECT TESTIMONY OF
RICHARD J. KRUSE

Q. Please state your full name, title and place of employment.

A. My name is Richard J. Kruse. I am Senior Vice President of Industry Initiatives, Pricing and Regulatory Affairs for Algonquin Gas Transmission Company ("Algonquin"). Algonquin's offices are located at 5400 Westheimer Court, Houston, Texas 77056.

Q. What is your educational background?

A. I received a Bachelor of Science in Economics from Texas Tech University in 1974 and graduated with a law degree from the University of Houston in 1977.

Q. Please describe your course of employment with Algonquin and the scope of your current duties and responsibilities for the company.

A. I started my employment in 1977 with Texas Eastern Transmission Corporation, now Texas Eastern Transmission, LP (both are referred to herein as "Texas Eastern"), in the rate department, which also was responsible for developing and implementing rates and pipeline tariffs. I subsequently transferred to the legal department, working principally with the rates and regulatory affairs groups at the company. In 1988, I was appointed Assistant General Counsel for Texas Eastern, and in 1990 I became Deputy General Counsel of Regulatory/Operations for Texas Eastern and Algonquin. In 1992, I was named Vice President and General Counsel for Texas Eastern and, in

1995, I was named Associate General Counsel of PanEnergy Corp., responsible for PanEnergy's interstate pipelines. In 1997, after the merger of PanEnergy Corp. and Duke Power Company, I was named Vice President and General Counsel of Gas Operations for the new Duke Energy Corporation, and in 1998, Vice President and General Solicitor. In 1999, I took a business position as Senior Vice President for Industry Initiatives, Pricing and Regulatory Affairs. In March 2000, I assumed responsibilities for rates and regulatory affairs. In my current position, I have responsibility for all of Algonquin's proceedings before the Federal Energy Regulatory Commission ("FERC"), which includes rates, certificate matters, and tariff matters generally. I have similar responsibilities for the other Duke Energy Gas Transmission pipelines and storage facilities, including Texas Eastern, East Tennessee Natural Gas Company, and Egan Hub Partners, L.P. and the pipelines that the Duke Energy Gas Transmission affiliates manage, such as Gulfstream Natural Gas System, L.L.C. and Maritimes & Northeast Pipeline, L.L.C. Finally, I am on the Board of Directors for the North American Energy Standards Board, an association of numerous energy section companies that addresses electronic communication and common business practice standards.

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

A. I am presenting testimony to provide (i) an overview of this filing and the testimony included as part of this Statement P, (ii) an understanding of the nature of the instant proceeding and the services at issue, (iii) an overview of the Algonquin pipeline system, and its tariff to provide context for the testimony, (iv) a summary of conclusions to be drawn from the testimony as a whole, (v) an overview of risks, including market and regulatory risk, associated with these services, and (vi) a summary of Algonquin's tariff revisions.

Q. Would you please outline the testimony that is being filed in this proceeding, besides your own.

A. Yes. The following testimony will be provided:

- Cost of service allocation, rate design and billing determinants – Gregg E. McBride, Exhibit No. __ (GEM-1).
- Capital structure, cost of debt, and rate of return on equity – Professor J. Peter Williamson, Exhibit No. __(JPW-1) and Exhibit Nos. __(JPW-2), (JPW-3), (JPW-4), (JPW-5).
- Books and records – Sabra L. Harrington, Exhibit No. __(SLH-1)

The testimony submitted in this Statement P is to be included with, and made a part of, the November 26, 2003 compliance filing in support of the one-part volumetric rates.

Q. Why did Algonquin initiate the proceeding in Docket No. RP04-24?

A. Algonquin initiated this proceeding in October 2003 to establish rates to be applicable on a prospective basis to any shippers using certain pipeline facilities, the Manchester Street and Brayton Point facilities, which had been built to provide firm transportation service to a specific customer and which were incrementally priced. As a result of the rejection of pre-existing contracts by USGen New England, Inc. ("USGen") in its bankruptcy proceeding, Algonquin no longer had firm contracts to recover the costs of service for such facilities.

Q. Why did Algonquin submit the November 26, 2003 filing in this proceeding?

A. On October 9, 2003, Algonquin filed with the FERC, in FERC Docket No. RP04-24, a proposal to implement meter access charges that would be applicable to all customers receiving service on the Manchester Street and Brayton Point facilities ("October 9 Filing"). On November 7, 2003, the FERC issued an order accepting and suspending Algonquin's tariff sheets in the October 9 Filing, effective October 10, 2003, subject to refund and conditions. The November 7 Order required that Algonquin re-file the tariff sheets, effective October 10, 2003, and supplement its tariff filing, tailoring the revised rates and services to provide for a continuation of the recovery of Algonquin's costs of service for the Manchester Street and Brayton Point facilities from appropriate shippers via one-part volumetric rates. In that regard, the November 7 Order directed Algonquin to reflect updated test period costs in calculating these revised rates.

Q. To provide context for Algonquin's proposal in this proceeding, could you please describe the history of the Manchester Street and Brayton Point facilities.

A. Algonquin had constructed the Manchester Street and Brayton Point facilities in the early 1990s, specifically to deliver gas to the Manchester Street and Brayton Point electric power generation plants for the predecessor of USGen New England, Inc. ("USGen"), New England Power Company ("NEP"), at NEP's request, at a capital cost of approximately $69 million. The Manchester Street facilities consist of looping, lateral facilities, and additional compression and metering facilities. The Brayton Point facilities consist of a lateral line and metering facilities.

After NEP permanently assigned its rights to service on these facilities to USGen, Algonquin provided firm service to and recovered its annual cost of service associated with the facilities from USGen, the sole shipper, under Rate Schedule AFT-1(X-38) and Rate Schedule AFT-CL(X-37) for the Manchester Street and Brayton Point facilities, respectively.

Q. Is USGen still a shipper under the AFT-1(X-38) and AFT-CL(X-37) contracts?

A. No. As noted above, USGen has rejected in its bankruptcy proceeding both the AFT-1(X-38) and AFT-CL(X-37) firm transportation contracts, thereby necessitating this rate filing. In particular, on July 8, 2003, USGen filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Maryland (Greenbelt Division) ("Bankruptcy Court"). Subsequently, USGen filed on August 12, 2003 with the Bankruptcy Court a motion for an order authorizing the rejection of the gas transportation agreements pursuant to which USGen, as shipper, received firm service at its Manchester Street plant under Algonquin's Rate Schedule AFT-1(X-38) and at its Brayton Point plant under Rate Schedule AFT-CL(X-37). On October 8, 2003, the Bankruptcy Court approved a Stipulation and Consent Order between Algonquin and USGen authorizing the rejection of these contracts effective September 11, 2003.

Q. As of this filing date, are there currently existing contracts for firm service on these facilities?

A. No. Following the rejection of these firm contracts, Algonquin promptly posted on its Internet website a notice advising interested parties of the availability of this capacity for shippers interested in executing new firm contracts. Since USGen's rejection of its firm contracts, however, there have been no contracts for firm service on the Manchester Street or Brayton Point facilities under Rate Schedule AFT-1(X-

38) or AFT-CL(X-37). On December 10, 2003, Algonquin and USGen entered into two contracts under Rate Schedule AIT-2, one for interruptible service on the Manchester Street facilities and the other for interruptible service on the Brayton Point facilities.

Q. What rates is Algonquin implementing in this proceeding?

A. As described in Mr. McBride's testimony and as reflected in the rate sheets and supporting statements and schedules in the November 26, 2003 filing, Algonquin is implementing one-part volumetric rates for firm transportation service of $0.6138 for AFT-CL(X-38) service and $1.0105 for AFT-CL(X-37) service. In addition, Algonquin is including a billing provision by which a customer electing to take firm service under Rate Schedules AFT-1(X-38) and AFT-CL(X-37) must pay for at least 80 percent of its contractual maximum daily transportation quantity ("MDTQ") on an annual basis. As required in the Commission's November 7 Order, Algonquin is also implementing a new AIT-2 service for interruptible service on the Manchester Street and Brayton Point facilities.

Q. Why is Algonquin implementing one-part volumetric rates for AFT-1(X-38) and AFT-CL (X-37) service in this proceeding?

A. One-part volumetric rates for AFT-1(X-38) and AFT-CL(X-37) services are appropriate in these particular circumstances. The demand component of a two-part rate is typically based on firm contract quantities and, as I have stated, Algonquin has no firm contracts for these services. One-part volumetric rates, on the other hand, are appropriately designed using historical volumetric throughput data which is available for the Manchester Street and Brayton Point facilities. Algonquin therefore has designed one-part volumetric rates for AFT-1(X-38) and AFT-CL(X-37) services that reflect historical volumetric throughput on the Manchester Street and Brayton Point facilities.

Q. Please further describe the need for and the terms of the billing provision under the firm rate schedules.

A. As discussed in more detail below, the billing provision for the AFT-1(X-38) and AFT-CL(X-37) services is necessitated by the implementation of one-part volumetric incremental rates for these firm services. Under this billing provision, if a customer takes less than 80 percent of its MDTQ on an annual basis, that customer will be charged as though it had taken 80 percent of its MDTQ. The amount due under the billing provision will be determined and billed on an annual basis. The provision is thus intended to accommodate any variations in load that customers, including electric generation plants, may experience during the year, and thereby permit these shippers to coordinate the timing of their payment obligations with their use of the pipeline system.

The requirement to pay at least 80 percent of the contracted capacity ensures that the AFT-1(X38) and AFT-CL(X37) capacity is used for its intended purpose. In particular, this billing provision is designed to prevent gaming of the system that would harm Algonquin and other parties, and promote accurate contracting and scheduling of capacity on these facilities. Without a reservation charge typical of a two-part rate design, the one-part volumetric rate design does not sufficiently protect the pipeline from customers contracting for large quantities of capacity and then using the contracted quantity of that capacity only on a peak basis. Absent the billing provision, customers may game the system by effectively turning their contracted service into a swing service, thus holding the capacity under contract for use on a firm basis – without payment of a reservation charge – and taking the full contractual amount during peak periods.

In sum, consistent with Commission precedent, the usage parameter in the billing provision discourages the gaming of the system, the use of the AFT-1(X-38) and AFT-CL(X-37) services as swing services for which Algonquin would not be compensated, and the hoarding of this pipeline capacity to the detriment of Algonquin and other parties that otherwise might occur in connection with a one-part volumetric rate.

Q. Is Algonquin likely to recover its costs of service for the Manchester Street and Brayton Point facilities if these rates are approved?

A. No. Algonquin is still at significant risk for recovering the costs of service for these facilities. As I have noted, Algonquin currently has no firm contractual agreements in place for service on the Manchester Street or Brayton Point facilities. Under the selected rate design, Algonquin would recover its cost of service in the event that Algonquin experiences on an annual basis volumetric load factors of 45% for service on the Manchester Street facilities and 5% for service on the Brayton Point facilities. It is unlikely that Algonquin will experience such annual load factors on these facilities, however. The actual annual volumetric load factor for the 12-month period ending September 30, 2003 for the Manchester Street facilities was only 30.1%, and for the Brayton Point facilities was only 1.0%. These percentages are significantly lower than the five-year averages. Furthermore, it is unknown at this time, especially in light of USGen's bankruptcy status, whether the plants fed by these facilities will be operated in the future. Even if these plants are operated, USGen has suggested by its rejection of the firm contracts that it no longer needs service on the Manchester Street and Brayton Point facilities.

In view of the fact that more recent deliveries on the Manchester Street and Brayton Point facilities have been materially below the annual volumetric load factor levels that Algonquin is using in this filing, and that Algonquin now has no firm contracts on the facilities, it is a virtual certainty that the design determinants will not be achieved. Algonquin could have justified rates materially above those requested, but the realities of the market place make it very unlikely that such rates could actually be collected.

Q. What is the purpose of the other testimony submitted by Algonquin in support of this filing?

A. Consistent with the November 7 Order, Mr. McBride explains how Algonquin has calculated the one-part volumetric rates for the AFT-1(X-38) and AFT-CL(X-37) services to reflect updated costs and data as required by the Commission's regulations. Mr. McBride also discusses the rate design and each of the corroborating statements, schedules and workpapers. In that regard, Mr. McBride provides details of the rate calculations based on revised cost data and Algonquin's capital structure, a detailed description of the billing determinants, the load factor, and the development of the one-part volumetric rate design for the two firm services. In addition, Mr. McBride describes the manner in which the AIT-2 rates, applicable to interruptible service on the Manchester Street and Brayton Point facilities, are designed.

Professor Williamson verifies Algonquin's choice of capital structure, cost of long-term debt and cost of equity in designing the rates for these services. Algonquin is proposing to use its actual capital structure and a cost of long-term debt based on its actual cost of outstanding debt, both as of September 30, 2003. In addition, Professor Williamson discusses Algonquin's proposal to use a rate of return on common equity of 16% for the rate design in this proceeding. Based on his determination of the required return on common equity for a set of publicly traded proxy companies relying on the Discounted Cash Flow method and a review of the particular business and financial risks associated with these services, Professor Williamson concludes in his testimony that such a cost of common equity is reasonable.

Finally, Ms. Harrington testifies that the updated cost statements, supporting data and workpapers included in the statements and schedules in this filing set forth the results shown in Algonquin's books as of September 30, 2003.

Q. Please provide an overview of the unique business risks facing Algonquin in recovering the costs of service for these facilities.

A. Algonquin faces two particular categories of risks with respect to its recovery of costs of service associated with providing future service on the Manchester Street and Brayton Point facilities. One of these categories is specific to these particular facilities while the second concerns Algonquin's entire system. The first set of risks involves the particular circumstances of the Manchester Street and Brayton Point facilities, which place Algonquin at significantly increased risk with respect to its cost recovery. As discussed above, since USGen rejected its contracts, Algonquin has no firm contracts for service on these facilities. Further, there has been a marked downward trend in the utilization of these facilities over the last five years. In summary, Algonquin is attempting in this filing to recover the costs of service associated with providing future service on the subject facilities, but Algonquin is certainly not assured of recovering its costs of service on these facilities through the revised rates.

As a result of the evolution of policies in the gas pipeline industry, Algonquin as a system is also confronted with certain regulatory risks. The Commission's current policies place incremental rates for new projects above the generally applicable system rate, at the same time as other Commission policies increase the operational flexibility of existing capacity, creating market forces that change the willingness or ability of shippers to pay for capacity on an incremental basis. The policies encouraging increased operational flexibility rely on the fact that all shippers do not regularly utilize all firm rights at the same time. This has greatly increased the substitutability of different forms of capacity, which has had the effect of materially reducing the value of incremental service. Incremental rates continue to reflect the costs of constructing expansion capacity for the shippers for whom that capacity was constructed. The expansion shipper may no longer be placing the same value on this incremental capacity, however, because the shipper may perceive that it can obtain similar service – through flexible receipt and delivery points and segmentation – at the system rate.

While these regulatory tensions present general issues for the pipeline industry, of particular relevance in this proceeding are those provisions in Algonquin's tariff that permit shippers under the Part 284 open access rate schedules to use incremental facilities without payment of the associated incremental rates. The provisions in Algonquin's pre-October 10, 2003 tariff that establish the terms and conditions for service on a secondary basis, including the curtailment provisions, as well as capacity release rights, increase the likelihood that Algonquin will not be able to recoup the cost of service associated with the Manchester Street and Brayton Point facilities. Under Algonquin's pre-October 10, 2003 tariff, shippers under the Part 284 open access rate schedules were able to use incremental facilities without payment of the associated incremental rates. A Part 284 shipper could utilize its own contracts at the generally-applicable rates to make deliveries on a secondary point basis on the Manchester Street and Brayton Point facilities. Furthermore, in addition to secondary service, the facilities could be served through released capacity, at system rates or below. The fundamental premise underlying these pre-October 10, 2003 tariff provisions relating to secondary service and capacity release is that the costs of service for the facilities are recovered under a separate incremental contract, which is no longer the case here in light of USGen's rejection of the AFT-1(X-38) and AFT-CL(X-37) contracts.

A solution to these conflicting policies may be either to preclude system customers from using the flexibility associated with the incremental capacity, or to change the incremental policy. This situation is not unique to the Manchester Street and Brayton Point facilities. Rather, these policies create similar risks for the entire system. As discussed more fully below, Algonquin has attempted to address this issue for the Manchester Street and Brayton Point facilities by precluding general system customers for using those facilities unless they pay the incremental rates related to those facilities and by precluding utilization of contracts for the incremental services to reach general system delivery points outside the contract path associated with the Manchester Street and Brayton Point facilities.

Q. What effect do these risks have on Algonquin's revised rates?

A. The increased financial and business risks associated with the Manchester Street and Brayton Point facilities support an upward adjustment in the cost of equity of a typical pipeline in the industry.

Professor Williamson conducted a Discounted Cash Flow ("DCF") analysis of five proxy companies, yielding a midpoint cost of equity of 15.25% for the proxy companies at this time. Professor Williamson chose five pipeline companies as his proxy companies. An upward adjustment to the 15.25% average cost of equity to 16% is reasonable due to the additional financial and business risks associated with the AFT-1(X-38) and AFT-CL(X-37) services discussed above. Therefore, I endorse 16% as an appropriate measure of the cost of equity.

Q. Please describe the basic terms of the new Rate Schedule AIT-2 implemented by Algonquin in this proceeding.

A. For interruptible service on the Manchester Street and Brayton Point facilities, Algonquin is proposing a new AIT-2 service, and has included a rate sheet, rate schedule and form of service agreement for such service. Service under Rate Schedule AIT-2 is patterned after service under the Commission-approved currently effective Rate Schedule AIT-1, with the exception that the AIT-2 service is only for interruptible service on the Manchester Street and Brayton Point facilities and that AIT-2 revenues are not eligible for General Terms and Conditions ("GT&C") Section 41 revenue crediting. Conforming changes have been made throughout the GT&C of Algonquin's tariff to add references to the new Rate Schedule AIT-2 in lists of rate schedule designations where applicable. Algonquin is also including a transition provision, which indicates that customers will pay the AIT-2 rate for firm service on the Manchester Street and Brayton Point facilities during the transition period from October 10, 2003 through December 9, 2003.

Q. Will the AFT-1(X-38), AFT-CL(X-37) and AIT-2 services affect Algonquin's nomination, scheduling and curtailment processes?

A. Yes. For purposes of determining available operational capacity during the scheduling process, Algonquin will treat the capacity of the Manchester Street and Brayton Point facilities as separate from other system capacity. Capacity made available through the Manchester Street and Brayton Point facilities will be utilized only to satisfy nominations made under Rate Schedules AFT-1(X-38), AFT-CL(X-37) and AIT-2. Algonquin will allocate capacity among the shippers under these rate schedules in accordance with the priorities in its tariff.

Q. Please describe the receipt and delivery point flexibility available under these rate schedules.

A. Customers under Rate Schedules AFT-1(X-38), AFT-CL(X-37) and AIT-2 have secondary receipt and delivery points within their respective contract paths. The issue of access to secondary points outside the contract path for these customers is specifically addressed in the terms of Rate Schedules AFT-CL(X-37) and AIT-2; the issue of receipt and delivery point flexibility associated with service under Rate Schedule AFT-1(X-38) is currently pending on clarification, or alternatively on rehearing, before the Commission. Ultimately, however, customers under these three rate schedules should be restricted to the secondary points within their contract paths on the Manchester Street and Brayton Point facilities. In addition, in accordance with the November 7 Order, Algonquin has modified the rate schedules in its tariff to provide that system customers will not have access to the Manchester Street or Brayton Point facilities on a secondary basis unless those customers have executed new contracts for AFT-1(X-38) or AFT-CL(X-37) service on those facilities, as applicable.

Q. Will the revenues under Rate Schedule AIT-2 be credited pursuant to the interruptible transportation revenue crediting mechanism set forth in GT&C Section 41?

A. No. Revenues from service under Rate Schedule AIT-2 are not included as eligible revenues for crediting purposes, since the costs associated with Rate Schedule AIT-2 are not included in the underlying cost of service for the GT&C Section 41 crediting mechanism. Any revenues associated with service under Rate Schedule AIT-2 are instead applied to the underlying cost of service for the Manchester Street and Brayton Point facilities.

Q. Please describe Algonquin's crediting mechanism in GT&C Section 49.

A. Consistent with the November 7 Order, Algonquin is proposing a crediting mechanism in GT&C Section 49 to provide the procedure by which Algonquin will credit the appropriate damages recovered through the bankruptcy proceeding. This provision states that, within 90 days after receipt by Algonquin of the final distribution from USGen on Algonquin's contract rejection damages claim, Algonquin will file a plan with the Commission showing the distributions received and the portion that should be credited to customers, along with the method for such crediting. In this manner, the crediting of damages in the bankruptcy proceeding will appropriately reflect any adjustment in the damage claim by the Bankruptcy Court as a result of the recovery of costs associated with service on the Manchester Street and Brayton Point facilities through the revised rates. Further, this provision allows for Algonquin to account for any disbursements that may have been allowed by the Bankruptcy Court but which are not actually recovered.

Q. Does that conclude your direct testimony?

A. Yes.

FINAL Richard Kruse testimony for RP04-24.DOC

AFFIDAVIT

THE STATE OF TEXAS)
)
COUNTY OF HARRIS)

I, Richard J. Kruse, being first duly sworn, do hereby depose and say that the foregoing constitutes my prepared testimony in this proceeding, that the answers to the questions therein stated are my answers to such questions and are true and correct to the best of my knowledge, information and belief.

Richard J. Kruse

Richard J. Kruse
Sr. Vice President, Industry Initiatives,
Pricing and Regulatory Affairs
Algonquin Gas Transmission Company

Subscribed and sworn before me
This 11th day of December, 2003

Barbara A Hulsey

Notary Public

My Commission Expires: 10-2.04

BARBARA A. HULSEY
Notary Public, State of Texas
My Commission Expires
OCTOBER 2, 2004
NOTARY PUBLIC STATE OF TEXAS

EXHIBIT NO. ___(GEM-1)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Algonquin Gas Transmission Company	§ § §	Docket No. RP04-24

PREPARED DIRECT TESTIMONY OF
GREGG E. MCBRIDE

Q. Please state your full name, place of employment, and title.

A. My name is Gregg E. McBride, and I am Vice President of Rates and Economic Analysis for Algonquin Gas Transmission Company ("Algonquin"). Algonquin's offices are located at 5400 Westheimer Court, Houston, Texas 77056.

Q. What is your educational background?

A. I received a Bachelor of Science degree in Accounting from Eastern Illinois University in 1978.

Q. Please describe your course of employment with Algonquin and the scope of your current duties and responsibilities for Algonquin.

A. I have been employed with Duke Energy Corporation and its predecessor corporations, PanEnergy Corp. and Panhandle Eastern Corp., since January 1979. I have held positions in the Regulatory Affairs Department of those corporations' respective natural gas pipeline companies for over 16 years. I have presented testimony for the pipeline companies in numerous proceedings before the Federal Energy Regulatory Commission ("Commission"). In addition, I have held positions of responsibility in the Investor Relations, Marketing and Capacity Management departments for the corporations listed above. As part of my current responsibilities, I oversee the preparation of various rate and tariff filings that

Algonquin files with the Commission. My responsibilities also include the preparation of economic analyses for various projects on Algonquin's behalf.

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

A. In the November 7 Order, the Commission held that the charges proposed by Algonquin in its October 9, 2003 tariff filing in this proceeding were "based on the most recently approved costs of the AFT-1(X-38) and AFT-CL(X-37) services" and therefore could be used to replace the existing two part rates, provided that they were re-filed to reflect updated test period costs. November 7 Order, at P 19. The November 7 Order noted that "[i]t is appropriate, in proposing new incremental rates, to reflect the most recent cost of service and billing determinants as required by the Commission's test period regulations." November 7 Order, at P 10. In accordance with the directives of this order, I am sponsoring the updated cost of service and rate design for the one-part volumetric rates applicable to service on the Manchester Street and Brayton Point facilities.

Q. What statements, schedules, or exhibits are you sponsoring in conjunction with your direct testimony?

A. I am sponsoring the following statements and schedules: Statements A, B, C, D, E, F-1, F-2, F-3, H-1, H-2, H-3, H-4, H-4(1), and J, and supporting Schedules B-1, C-1, E-2, and H-3(1). These statements and schedules were all included in Appendix C of the November 26 Filing and are hereby included in and become a part of my testimony.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes, all of these statements and schedules were prepared under my direction and supervision.

Q. Are there other statements and schedules contemplated by the Commission's regulations in Part 154 that are not included as part of the November 26 Filing?

A. Yes. Appendix C of the November 26 Filing included the statements and schedules necessary to reflect the most recent cost of service and to revise the billing determinants to reflect the 12 months ending September 30, 2003, thereby meeting the requirements of the November 7 Order. Certain statements and schedules were not included in this compliance filing because they were not necessary for the updating of costs and billing determinants for these two projects.

Q. Please explain generally how Algonquin updated the costs and data to reflect the most recent cost of service and billing determinants in this proceeding.

A. Algonquin updated its cost of service to reflect actual data for the 12 months ending September 30, 2003. Ms. Sabra Harrington, Vice President and Controller for Algonquin, provided me with the data reflected in the statements and schedules. As verified by Ms. Harrington, the data included in this filing reflects the results in Algonquin's books and records, except as noted in my testimony.

Q. How did Algonquin assign system-wide operation and maintenance ("O&M") expenses to the AFT-1(X-38) and AFT-CL(X-37) services?

A. Consistent with Commission policy, Algonquin has allocated certain costs on the basis of the ratio of (i) gas plant in service for the Manchester Street and Brayton Point facilities, which are recorded in separate plant sub-accounts, to (ii) the total Algonquin gas plant in service as of September 30, 2003, as reflected in

Algonquin's books. Algonquin has applied this plant ratio to its system-wide transmission O&M and administrative and general ("A&G") expenses (less gas costs, GRI and ACA). The resulting ratios were 6.25% for the Manchester Street facilities and 1.59% for the Brayton Point facilities. *See, e.g., Transcontinental Gas Pipe Line Corp.*, 101 FERC ¶ 63,022, at ¶ 289 (2002); *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 (1999), *order on reh'g*, 96 FERC ¶ 61,049, at p. 61,120 (2001).

Q. Were any other cost items assigned in this way?

A. Yes. Algonquin's system-wide working capital and payroll taxes were allocated to the AFT-1(X-38) and AFT-CL(X-37) services using the same gross plant factors.

Q. Has Algonquin used a 9-month test period to project cost of service underlying the AFT-1(X-38) and AFT-CL(X-37) rates?

A. No. Given the unique circumstances surrounding this filing, as discussed by Mr. Kruse, Algonquin's rate request was immediate in nature and Algonquin requested rates effective as of the day after the original filing. Instead of the traditional test period concept of Part 154, Algonquin therefore has relied on its most recent actual experience for the 12 months ended September 30, 2003 for its cost of service and rate calculations. As noted above, this approach is consistent with the Commission's requirement that Algonquin submit an updated cost of service to justify its rates.

Q. What adjustments, if any, were made to the actual data for 12 months ended September 30, 2003?

A. There were no adjustments made to actual data for changes that might occur after September 30, 2003. However, the following items were eliminated from Algonquin's transmission O&M and A&G expenses before these expenses were assigned to the two projects: (i) gas costs which are recovered separately under Algonquin's FRQ mechanism, and (ii) ACA and GRI amounts that are recorded as expenses on Algonquin's books but are recovered as separate surcharges under its FERC tariff.

Q. Please describe the statements that set out the calculations for the cost of service for the 12-month period described above.

A. Statement A summarizes the overall cost of service for the AFT-1(X-38) and AFT-CL(X-37) services for the 12-month period ending September 30, 2003. As shown on Line 7, the total cost of service for AFT-1(X-38) is $9,623,667 and for AFT-CL(X-37) is $2,212,895. The cost of service consists of O&M expense, depreciation expense, income taxes, other taxes, and return based on an overall rate of return of 11.21%, as developed in Statements H-1, H-2, H-3 and H-4, and B, respectively. Additional information regarding the rate of return is included in the testimony of Richard J. Kruse, Exhibit No. ___(RJK-1) and Professor J. Peter Williamson, Exhibit No. ___(JPW-1).

Q. Please explain Statement B.

A. Statement B summarizes the rate base and return as derived in Statements C, D, E, and Schedules B-1 and F-2. The rate base consists of the sum of net plant and working capital, reduced by accumulated deferred income taxes. The rate base for the Manchester Street and Brayton Point facilities is $33,509,165 and

$4,641,925, respectively. The overall rate of return of 11.21% yields an overall return on rate base of $3,756,377 and $520,360 for the AFT-1(X-38) and AFT-CL(X-37) services, respectively.

Q. Please describe Schedule B-1.

A. Schedule B-1 sets forth the accumulated deferred federal and state income taxes deducted from the rate base for the AFT-1(X-38) and AFT-CL(X-37) services as of September 30, 2003. The total deferred income taxes deducted from rate base for the Manchester Street and Brayton Point facilities are $9,027,381 and $1,384,323, respectively. These amounts were calculated based on the difference between the total book depreciation and tax depreciation from the in-service date of each project through September 30, 2003. Algonquin is omitting Schedule B-2 because there are no regulatory assets or liabilities associated with these facilities.

Q. Please describe the contents of Statement C and its supporting schedules.

A. Statement C provides a summary of the cost of plant for Accounts 101 through 107, 117.1 and 117.2. The total costs of plant for the Manchester Street and Brayton Point facilities are $54,747,973 and $13,927,659, respectively. Schedule C-1 shows the detail of the plant balances for Gas Plant in Service for the facilities as of September 30, 2003.

Q. What is contained in Statement D?

A. Statement D sets forth accumulated depreciation, depletion and amortization from Account 108, Account 111, and Account 115 as of September 30, 2003. These totals are incorporated in Statement B to determine total rate base for the Manchester Street and Brayton Point facilities.

Q. Please explain Statement E and Schedule E-2.

A. Statement E reflects the components of working capital shown in Statement B as part of the rate base. Schedule E-2 shows Algonquin's 13 monthly balances, from September 1, 2002 through September 30, 2003 for materials and supplies (Account 154) and pre-payments (Account 165), allocated to the Manchester Street and Brayton Point facilities. The average of these 13 monthly balances is $71,804 for the Manchester Street facilities and $18,267 for the Brayton Point facilities. The working capital does not include a separate allowance for cash working capital. Algonquin allocated the system-wide monthly balances to the AFT-1(X-38) and AFT-CL(X-37) services using the same plant ratios used to allocate O&M and A&G expenses as shown above.

Q. Please explain Statement F-1.

A. Statement F-1 explains that Algonquin is proposing a return on equity of 16% for the AFT-1(X38) and AFT-CL(X-37) services. This rate of return is endorsed by Mr. Richard J. Kruse, Exhibit No. ___(RJK-1), and Professor Williamson, Exhibit No. ___(JPW-1), in light of the risks associated with the recovery of costs of service for these facilities.

Q. Please explain Statement F-2.

A. Statement F-2 shows the detail of Algonquin's capital structure, the debt and equity costs and the resulting overall rate of return. Algonquin is using its actual capital structure, as of September 30, 2003, of 46.49% long-term debt and 53.51% equity, which was provided to me by Ms. Harrington. As shown on Statement

F-2, Algonquin is using a cost of debt of 5.71% which is Algonquin's actual cost of long-term debt capital as of September 30, 2003.

Q. Please explain Statement F-3.

A. Statement F-3 sets out Algonquin's cost of long-term debt capital. The sources of debt are shown, along with the calculation of the weighted average 5.71% debt cost.

Q. Please explain Statement H-1.

A. Statement H-1 shows by FERC account Algonquin's transmission O&M and A&G expenses assigned to the AFT-1(X-38) and AFT-CL(X-37) services. Algonquin has developed these transmission O&M and A&G expenses by first removing gas costs and ACA and GRI expenses from its per book numbers and then multiplying the netted twelve months of actual expenses ending September 30, 2003 by the same plant ratios used to allocate O&M and A&G expenses above. The resulting allocated transmission O&M and A&G expenses were $2,696,881 and $686,084 for the AFT-1(X-38) and AFT-CL(X-37) services, respectively.

Q. Has Algonquin made any changes in or adjustments to the book values in the accounts other than applying the percentage attributable to the Manchester Street and Brayton Point facilities?

A. As noted above, Algonquin has deducted from the total Algonquin transmission O&M and A&G expenses gas costs subject to recovery in its FRQ, as well as ACA and GRI amounts. Since ACA and GRI are surcharges added to customers' bills, reflecting these charges in the total transmission O&M and A&G expenses would lead to double recovery. Other than the removal of these items, no adjustments to the book transmission O&M and A&G expenses were made.

Q. Please explain why only transmission O&M and A&G expenses were reflected on Statement H-1.

A. O&M expenses other than transmission O&M and A&G were considered to be inapplicable to the Manchester Street and Brayton Point facilities. For instance, no storage-related line items are included in this statement because there are no storage facilities associated with the AFT-1(X-38) or AFT-CL(X-37) services on Algonquin's system. Thus, Statement H-1 includes only transmission O&M and A&G expenses.

Q. Please explain Statement H-2.

A. Statement H-2 shows the depreciation, depletion and amortization expense allocated to the AFT-1(X-38) and AFT-CL(X-37) services. The depreciation rate for AFT-1(X-38) service is the Commission-approved system rate of 1.81%. *Algonquin Gas Transmission Co.*, 95 FERC ¶ 61,077, at p. 61,229 (2001). The depreciation rate for the AFT-CL(X-37) service is the Commission-approved depreciation rate of 4.00%. These depreciation rates were applied to the September 30, 2003 depreciable gas plant in-service balances to derive the depreciation expense for the two projects. *Algonquin Gas Transmission Co.*, 87 FERC ¶ 61,008 (1999).

Q. What is reflected in Statement H-3?

A. Statement H-3 shows the computation of $256,740 and $1,554,783 in state and federal income taxes, respectively, for the Manchester Street facilities, and

$35,826 and $216,957 in state and federal income taxes, respectively, for the Brayton Point facilities, for the 12-month period ending September 30, 2003. Based on the composite state income tax rate developed on Statement H-3(1), Algonquin has calculated state income taxes on Line 10 by multiplying the applicable taxable income by the composite state income tax rate of 5.46374%. Algonquin has calculated the federal income taxes on Line 11 by multiplying the applicable taxable income by the federal income tax rate of 35%.

Q. What is reflected in Statement H-4?

A. Statement H-4 shows the property taxes by state assigned to the Manchester Street and Brayton Point facilities. These amounts were allocated using the actual tax payments for those states during the twelve month period ending September 30, 2003. Statement H-4(1) calculates the payroll taxes for the Manchester Street and Brayton Point facilities for the twelve month period ending September 30, 2003, using the allocation ratios of plant costs for the respective facilities to the total Algonquin plant. Applying the same plant allocation ratios of 6.25% for the Manchester Street facilities and 1.59% for the Brayton Point facilities to the total payroll taxes, Algonquin has allocated $51,580 and $13,122 of payroll taxes to the AFT-1(X-38) and AFT-CL(X-37) services, respectively.

Q. Please explain the rate design for firm services used by Algonquin in this proceeding.

A. Algonquin has developed one-part volumetric rates for the firm AFT-1(X-38) and AFT-CL(X-37) services in this proceeding. To determine these rates, Algonquin has divided the cost of service, as reflected on Statement A, by annual volume determinants projected using the average annual load factor over the past five years, as described below.

Statement J shows the computation of the proposed firm rate for AFT-1(X-38) service by dividing the AFT-1(X-38) cost of service by the annual volume determinants equal to a 45% average annual load factor. The proposed firm rate for AFT-CL(X-37) is calculated by dividing the AFT-CL(X-37) cost of service by the annual volume determinants equal to a 5% average annual load factor.

Q. Please explain how you established the level of annual volume determinants used to design the AFT-1(X-38) and AFT-CL(X-37) rates for firm services.

A. In establishing the level of determinants for firm services, Algonquin had to determine the appropriate balance between (i) a rate design that will recover its cost of service associated with the Manchester Street and Brayton Point facilities, and (ii) the realities of the marketplace. As a result, Algonquin is undertaking significant risk with respect to the selected annual volume determinants.

As more fully explained by Mr. Kruse, whether Algonquin recovers its costs of service pursuant to the rates proposed in this filing will depend on how the Manchester Street and Brayton Point facilities are used in the future. Algonquin currently has no firm contracts for service on those facilities and it is not evident what shippers will use these facilities. USGen has indicated in the bankruptcy proceeding that it no longer will require firm transportation contracts on Algonquin. Consequently, as Mr. Kruse indicates, the risk that Algonquin will not be able to sell this capacity on a firm basis is extremely significant, particularly with respect to the Brayton Plant facilities that extend only to the Brayton Point generating facility.

As a review of recent annual load factors at these facilities demonstrates, the quantities of natural gas transported on the Manchester Street and Brayton Point facilities have been declining. The actual load factor for the 12-month period ending September 30, 2003 for the Manchester Street facilities was only 30.1% as shown on page 2 of Statement J. Similarly, as shown on page 4 of Statement J, the actual load factor for the 12-month period ending September 30, 2003, for the Brayton Point facilities was only 1.0%.

While Algonquin has attempted to design a rate that will provide at least an opportunity to recover some of its costs of service on the incremental facilities from the appropriate shippers, it is unlikely that these rates will recover all of its costs of service. Algonquin has used the five-year average of actual annual load factors for the Manchester Street and Brayton Point facilities to design the AFT-1(X-38) and AFT-CL(X-37) rates. The five year average annual load factors for the Manchester Street and Brayton Point facilities are 46.2% and 4.0%, respectively, and Algonquin has utilized annual volume determinants of 45% and 5% in developing the AFT-1(X-38) and AFT-CL(X-37) rates, respectively. In view of the fact that more recent deliveries on the Manchester Street and Brayton Point facilities have been materially below these levels and that Algonquin now has no firm contracts on those facilities, it is a virtual certainty that these design determinants will not be achieved. Algonquin could have justified rates materially above those requested, but the realities of the marketplace make it very unlikely that such rates could actually be collected.

Q. How did you determine the interruptible rates for these facilities under Rate Schedule AIT-2?

A. As required by the Commission's November 7 Order, and consistent with Commission policy and precedent, Algonquin has designed interruptible rates for the AIT-2(X-38) and AIT-2(X-37) services equal to the 100 percent load factor rates of the firm AFT-1(X-38) and AFT-2(X-37) rates, respectively.

Q. What is the Commission's policy with respect to load factors and calculation of the interruptible rate?

A. Generally, the Commission provides that interruptible rates should be designed in such a manner that the total rate that an interruptible shipper would pay for service during a month should equal, on a per unit basis, the total amount paid by a firm shipper who contracted for that same quantity in a month, when that firm shipper takes 100% of its contractual quantities during the month. As a result of using a one-part volumetric rate for firm services with the firm customer paying on a per-unit basis, the necessary result is that the 100% load factor rate for interruptible service equals the same rate as the firm rate design produces. By way of example, the total amount paid by an interruptible shipper taking 100 units per month at a rate of $0.6138 per Dth would equal $61.38. Likewise, the total amount paid by a firm shipper taking 100 units per month under its firm contract at a volumetric rate of $0.6138 per Dth would equal $61.38. As reflected above, the total amount paid in both circumstances is the same.

Q. Does Algonquin's rate structure comply with this Commission principle with respect to interruptible rates?

A. Yes. As noted above, Algonquin's interruptible rates are equal to the 100% load factor rates of the corresponding firm rates for service on the Manchester Street and Brayton Point facilities. As shown on Statement J, the AIT-2(X-38) rate of $0.6138 is the 100% load factor rate of the firm AFT-1(X-38) rate. The AIT-2(X-37) rate of $1.0105 is the 100% load factor rate of the AFT-CL(X-37) rate.

Q. Does this conclude your prepared direct testimony?

A. Yes.

FINAL Gregg McBride Testimony for RP04-24.DOC

AFFIDAVIT

THE STATE OF TEXAS)
)
COUNTY OF HARRIS)

I, Gregg E. McBride, being first duly sworn, do hereby depose and say that the foregoing constitutes my prepared testimony in this proceeding, that the answers to the questions therein stated are my answers to such questions and are true and correct to the best of my knowledge, information and belief.

Gregg E. McBride

Gregg E. McBride

Vice President, Rates & Economic Analysis
Algonquin Gas Transmission Company

Subscribed and sworn before me
This 10th day of December, 2003

Barbara A. Hulsey

Notary Public

My Commission Expires: 10-2-04

NOTARY PUBLIC STATE OF TEXAS
BARBARA A. HULSEY
Notary Public, State of Texas
My Commission Expires
OCTOBER 2, 2004

EXHIBIT NO. ___(SLH-1)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	§	
Algonquin Gas Transmission Company	§	Docket No. RP04-24
	§	

PREPARED DIRECT TESTIMONY OF
SABRA L. HARRINGTON

Q. Please state your name and business address.

A. My name is Sabra L. Harrington. My business address is 5400 Westheimer Court, Houston, TX 77056-5310.

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

A. I am the Vice President and Controller for Algonquin Gas Transmission Company ("Algonquin"), which is a subsidiary of Duke Energy Gas Transmission Corporation ("DEGT"). In that capacity, I oversee the preparation and maintenance of the books and records of Algonquin.

Q. Please briefly summarize your education and professional background.

A. I graduated with honors from Stephen F. Austin State University, earning a bachelor of business administration degree in accounting and am a certified public accountant. After college, I worked for Arthur Andersen for 4 years as an auditor and then took a position at DEGT, where I am currently employed. In my 15 years with DEGT, I have held a number of accounting positions of increasing responsibility in the controller's department, gaining a vast amount of experience working with the company's pipeline systems and corporate reporting areas. These positions have included Manager of Public Reports (Corporate), Manager of Gas Accounting and Revenue Billing (MidWest Pipelines), and Director of

Accounting (Northeast Pipelines). I was the controller for DEGT's pipelines in the U.S. immediately prior to my current position as Vice President and Controller of DEGT.

Q. Were Algonquin's books and records for the base period in this proceeding prepared under your supervision and direction?

A. Yes.

Q. Can you please verify for the record that the cost statements, supporting data, and workpapers in the statements and schedules filed in this proceeding that purport to reflect the books of Algonquin do, in fact, set forth the results shown by such books?

A. The cost statements, supporting data, and workpapers set forth in the statements and schedules filed in this proceeding do in fact reflect and set forth the results shown by the books of Algonquin as of September 30, 2003, except as specifically noted in the testimony of Gregg McBride.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

FINAL Sabra L. Harrington Testimony (RP04-24)

AFFIDAVIT

THE STATE OF TEXAS)
)
COUNTY OF HARRIS)

I, Sabra L. Harrington, being first duly sworn, do hereby depose and say that the foregoing constitutes my prepared testimony in this proceeding, that the answers to the questions therein stated are my answers to such questions and are true and correct to the best of my knowledge, information and belief.

Sabra L. Harrington
Sabra L. Harrington

Vice President of Finance and Controller
Algonquin Gas Transmission Company

Subscribed and sworn before me
This 10th day of December, 2003

Barbara A. Hulsey
Notary Public

My Commission Expires: 10-2-04

NOTARY PUBLIC STATE OF TEXAS
BARBARA A. HULSEY
Notary Public, State of Texas
My Commission Expires
OCTOBER 2, 2004

EXHIBIT NO. ___(JPW-1)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	§	
Algonquin Gas Transmission Company	§	Docket No. RP04-24
	§	

PREPARED DIRECT TESTIMONY OF
J. PETER WILLIAMSON

Q. Please state your name and business address.

A. My name is J. Peter Williamson. My business address is 89 Main Street, West Lebanon, New Hampshire 03784, and P.O. Box 5160, Hanover, New Hampshire 03755.

Q. What is your occupation?

A. I am the Laurence F. Whittemore Professor of Finance Emeritus at the Amos Tuck School of Business Administration, Dartmouth College. I have retired from teaching and continue to act as a consultant to various organizations, both business and nonprofit institutions, on matters pertaining to corporate finance and investments. I have testified in numerous proceedings before the Federal Energy Regulatory Commission and other regulatory agencies regarding cost of equity, capital structure and other financial matters. My education and qualifications are set out in some detail in my Exhibit No. __(JPW-2).

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

A. This case concerns the appropriate charges for recovery of costs associated with certain pipeline facilities known as the Manchester Street and Brayton Point facilities. Algonquin Gas Transmission Company ("Algonquin") had constructed these facilities to provide firm transportation service to electric generation plants now owned by USGen New England, Inc. ("USGen"). Algonquin's filing initiating this proceeding was necessitated by the rejection of the pre-existing firm transportation contracts by USGen, which has declared bankruptcy. I have been asked to verify the capital structure, the cost of long-term debt, and the cost of common equity appropriate for use in determining the revised rates for the Manchester Street and Brayton Point facilities.

<u>Summary</u>

Q. Please summarize your verification of the capital structure that should be used for Algonquin.

A. For purposes of this proceeding, Algonquin is using its own capital structure, as of September 30, 2003, of 53.51% equity and 46.49% debt. Algonquin does its own debt financing, without guarantees from its parent. The 53.51% equity ratio is well within the range of equity percentages allowed by the Commission in prior cases, and therefore is consistent with the Commission's guidelines for capital structure set out in Opinion No. 414-A. *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084 (1998). As such, this capital structure is reasonable.

Q. Please summarize your verification of the cost of long-term debt for Algonquin.

A. Algonquin proposes to use the actual cost of its outstanding debt of 5.71% as its cost of debt in this proceeding.

Q. Please summarize your verification of the cost of equity for Algonquin.

A. Algonquin proposes to use 16% as its cost of equity in this proceeding. It is impossible to establish directly the cost of equity for Algonquin because Algonquin has no equity securities that are publicly traded. Algonquin is indirectly 100% owned by Duke Energy Corporation. My overall approach to verification of the proposed cost of equity was to determine the required return on common equity for a set of publicly traded proxy companies and to adjust this cost of equity to reflect the risk for Algonquin. In determining the cost of common equity for these proxy companies, I relied on the Discounted Cash Flow ("DCF") method.

Q. Please describe your use of the DCF method.

A. I applied the DCF method to five publicly traded proxy pipeline companies: Enterprise Products Partners L.P. ("Enterprise"), GulfTerra Energy Partners, L.P. (formerly El Paso Energy Partners, L.P.) ("GulfTerra"), Kinder Morgan Energy Partners, L.P. ("KMEP"), Kinder Morgan, Inc. ("KMI"), and Northern Border Partners, L.P. ("Northern Border"). I shall explain my choice of these five companies later in this testimony.

Q. Using your set of five proxy companies, how did you proceed?

A. I determined the dividend yields for the proxy companies, as the DCF model requires. Then I turned to forward-looking estimates of growth. I made use of analysts' earnings growth projections reported by I/B/E/S International, Inc. ("IBES"). I believe that the combination of dividend yields and IBES-reported earnings growth forecasts is the most reliable measure of the cost of common equity for use in the DCF model. However, the Commission has decided in recent years to make use of a combination of forecasts of earnings growth from IBES and forecasts of Gross Domestic Product ("GDP") growth from three (now two) different sources, in combination with dividend yields. The Commission's most recent statement of its policy is set out in Opinion No. 414-A, *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084 (1998). I therefore applied the Commission's methodology.

Q. What were your conclusions from application of the DCF method to the proxy companies?

A. Making use of the set of five proxy pipeline companies, the GDP growth forecasts of the Energy Information Administration ("EIA") and Global Insight, the IBES-reported earnings growth forecasts, and the Commission's DCF methodology, I found the mean and median to be 15.25%.

Q. In the past, the Commission has used El Paso Corp. ("El Paso") and The Williams Companies, Inc. ("Williams") as proxy companies in gas pipeline rate proceedings. Why did you not include those two companies?

A. I believe the inclusion of El Paso and Williams to be inappropriate at the present time. Briefly, both companies have encountered serious difficulties with their energy trading operations, and have drastically reduced their dividends. As a result, I do not believe that the two companies continue to be suitable for inclusion in a DCF analysis, which is designed for companies with significant dividends. Further, since their stock prices and dividend distributions have plunged for reasons that I understand have little to do with pipeline operations, neither company at present is a useful representative of the gas pipeline industry.

Q. What is your final conclusion with respect to the cost of equity for gas pipelines and for Algonquin?

A. I believe that, on the basis of the analysis of five proxy pipeline companies, the cost of equity for gas pipelines is about 15.25%. The cost of equity for the Manchester Street and Brayton Point facilities is determined by an upward adjustment to the required return on equity for the set of proxy companies to reflect additional risks associated with the recovery of the costs of the Manchester Street and Brayton Point facilities.

Algonquin's Capital Structure

Q. You have said that Algonquin's actual capital structure of 53.51% equity and 46.49% debt is a reasonable one. What is the basis for your conclusion?

A. The Commission has made clear in decisions beginning with Opinion No. 414-A that a test of reasonableness is a comparison of the company's equity ratio to equity ratios accepted by the Commission in past cases. For example, in *Williams Natural Gas Co.*, the Commission confirmed its acceptance of Williams' 64.29% equity ratio as "not anomalous when compared to other equity ratios approved by the Commission." 86 FERC ¶ 61,232, at p. 61,856 (1999) The language of the *Williams* decision was quoted in *Northwest Pipeline Corp.*, 92 FERC ¶ 61,287, at p. 62,005 (2000), as well as in *Transcontinental Gas Pipe Line*, 90 FERC ¶ 61,279, at p. 61,936 (2000). The importance of comparisons to capital structures approved by the Commission for gas pipeline companies was emphasized in Opinion No. 414-B, *Transcontinental Gas Pipe Line Corp.*, 85 FERC ¶ 61,323, at p. 62,265 (1998). I show in my Exhibit No. __(JPW-5) a table of equity ratios approved in nine recent FERC decisions, ranging from a low of 55% to a high of 68.9% equity.

Algonquin's Cost of Long-Term Debt

Q. On what is Algonquin's proposed cost of long-term debt of 5.71% based?

A. Algonquin's proposed cost of long-term debt is based on its actual cost of outstanding debt as of September 30, 2003, as noted in Statement F-1 of Algonquin's November 26 compliance filing in this proceeding.

<u>DCF Method for Cost of Equity</u>

Q. Please explain the DCF method for determining the cost of equity.

A. The origin of the DCF method can be found in the work of John Burr Williams, published in 1938 and entitled *The Theory of Investment Value*. Williams said the value of a share of stock is the discounted present worth of all the dividends to be received on that share. The equation he set out is:

$$\text{Share Value} = Div_1/(1+i) + Div_2/(1+i)_2 + Div_3/(1+i)_3 + \ldots$$

where Div_1 is the dividend to be received next year; Div_2 is the dividend to be received in the following year, and so on until the dividends cease. (*The Theory of Investment Value*, pp. 55- 56.) The denominator in each term in the right hand side of the equation is a discount factor and ***i*** is (in Williams' words) the "interest rate sought by the investor." He went on to point out that if dividends are expected to grow at a constant rate ***g***, then $Div_2 = Div_1(1+g)$ and so on, and $Div_1 = Div_0(1+g)$, where Div_0 is the dividend in the year just past. (*The Theory of Investment Value*, pp. 87-88.) Further, if we assume that the stream of dividends is infinite then the equation above becomes:

$$\text{Share Value} = Div_0(1+g)/(i-g)$$

Williams also considered cases in which dividends are not expected to grow at a uniform rate and produced somewhat more complicated equations incorporating changes in the rate of growth.

Q. Is it the Williams equation you used in your determination of the cost of common equity for Algonquin?

A. I used the equation in a different form. Williams was concerned with determining the value of a share of stock. His starting point was the investor's desired rate of return.

Professors M. J. Gordon and E. Shapiro turned the Williams equation around to the form generally recognized as the DCF equation for the cost of common equity. In an article published in 1956, Gordon and Shapiro pointed out that if we *start* with a figure for the value in the Williams equation we can *calculate* the investor's desired rate of return. ("Capital Equipment Analysis: The Required Rate of Profit," 3 *Management Science* 102, October 1956.) If the *market price* is used for value, then the equation will give us the rate of return required by the *market.*

The Gordon and Shapiro version of Williams' constant growth equation is:

Share Price $P_0 = Div_0/(k-g)$

so that $k = Div_0/P_0 + g$

where *k* is the rate of return required by the market (not necessarily by any particular investor), Div_0 is the dividend in the year just ended and P_0 is the price at the point in time when *k* is determined.

Q. Did you use the equation above in your determination of the cost of common equity for Algonquin?

A. Not quite. There is a small difference between the Gordon and Shapiro equation:

$$k = Div_0/P_0 + g$$

and the Williams equation, which can be rewritten as:

$$k = Div_1/P_0 + g$$

$$= Div_0(1+g)/P_0 + g$$

The difference is due to Williams' assumption that dividends are paid once a year at the year end, while Gordon and Shapiro assumed that they are paid continuously. Neither assumption is quite correct, and the Commission has expressed a preference for a third formulation:

$$k = (1+.5g)y + g$$

where k = market required rate of return;

$y = Div_0/P_0$ = current dividend yield (current annual dividend divided by current market price);

g = dividend growth rate;

and $(1 + .5g)$ = dividend adjustment factor for quarterly dividend payments.

I have used the FERC formula above, and applied it to the proxy companies.

Q. In *Enbridge Pipelines (KPC)*, the Commission appears to have stated that the adjustment factor (1+.5g) for quarterly dividend payments is not permissible. 100 FERC ¶ 61,260, at p. 61,967 (2002). Is your adjustment then incorrect?

A. I believe there is some confusion in the *Enbridge* decision. The Commission Staff dealt with the adjustment in a different way in that proceeding, a way which leads to exactly the same result as the adjustment I have described, and seems to have been acceptable to the Commission.

Q. Please describe the Staff method of adjusting the dividend yield.

A. In Opinion No. 414-A, the Commission relied on Staff testimony that averaged the "continuous" dividend yield with the "discrete" dividend yield. The continuous yield is the ratio Div_0/P_0, from the Gordon and Shapiro formula above. (See Exhibit No. S-20, p. __, in Docket Nos. RP95-197 and RP96-44.) The discrete yield is calculated as (Div_0/P_0) x (1+g), from the Williams equation above. Averaging the two leads to the same result as (Div_0/P_0) x (1+.5g).

In the *Enbridge* case, the Staff witness actually set out the formula using the adjustment factor (1+.5g) (see Exhibit No. S-20, p. 13), but used the continuous and discrete yields to determine his cost of equity for each proxy company (see Exhibit No. S-20, p. 2).

To make the calculation quite clear, I shall use both the adjustment I have described and Staff's adjustment in my exhibits, to show that they are equivalent.

<u>The Use of Proxy Companies</u>

Q. Please explain the use of proxy companies for the application of the DCF model.

A. The "market based" DCF model can only be applied to companies for which the common stock is publicly traded. Almost all of the natural gas pipeline companies that are regulated by the FERC are to my knowledge not themselves publicly traded. They are subsidiaries of diversified natural gas companies that are publicly traded. It has been the practice of the FERC to apply the DCF model not to regulated natural gas pipelines directly, but to a set of proxy companies that are publicly traded and are what the Value Line, Inc. ("Value Line") calls "diversified natural gas companies."

Q. How did you choose your particular set of proxy pipeline companies?

A. I first considered the publicly traded companies that I have used in recent testimony and that the Commission has used in decisions involving gas pipelines, including Opinion No. 414-A. The six proxy companies used in Opinion No. 414-A were Coastal Corporation ("Coastal"), El Paso Energy Corporation, now El Paso Corporation, Enron Corp. ("Enron"), Panhandle Energy

("Panhandle"), Sonat Inc. ("Sonat"), and Williams. Since that time Coastal, Panhandle and Sonat have ceased to be publicly-traded. Enron is bankrupt, and the only remaining companies are El Paso and Williams. Both of those companies have encountered serious problems (unrelated, I believe, to the operations of their pipelines) that make them inappropriate as proxy companies.

Q. Please explain more fully why El Paso and Williams are no longer appropriate choices as proxy companies.

A. The stock price of El Paso has dropped from a high of $47 per share in May 2002 to about $6 currently, I believe, largely because of problems with its trading activities and lack of liquidity. El Paso's annual dividend has been cut to $0.16 per share from $0.872 per share, making doubtful the suitability of a DCF analysis, which depends on dividends. In its March 2003 report, Value Line described the company as "a speculative long-term holding," and in its June 2003 report continued to use the term "speculative" in describing El Paso. As a result, a DCF analysis applied to El Paso is not a measure of the current cost of equity to a gas pipeline.

Similarly, the stock price of Williams dropped precipitously from about $24 per share to about $1 per share, and has recovered to only about $9, again in part because of trading activities and liquidity problems. In addition, Williams reduced its annual dividend from $0.80 per share to $0.04 per share. In effect, Williams came almost as close as possible to ceasing dividends without quite doing so. One cent per share per quarter is, I believe, close to the minimum dividend a company could pay and still claim not to have suspended its dividends altogether. This makes Williams almost a non-dividend-paying company, and the

DCF methodology was not intended for application to a company that does not pay dividends.

Neither company is representative of the gas pipeline industry at the present time and neither should be used in a DCF analysis to determine the cost of equity for gas pipelines.

Q. Please continue with your description of your proxy companies.

A. I have replaced the now unusable group with Enterprise, GulfTerra, KMEP, KMI, and Northern Border. Enterprise owns participating interests in several gas pipelines. GulfTerra is the former El Paso Energy Partners, L.P., a publicly traded partnership with its units listed on the New York Stock Exchange. It has both gas and oil operations, with the gas operations predominant. KMEP has been known as primarily an oil pipeline company for many years, but has diversified substantially into gas pipelines. KMI, which until October 1999 was known as KN Energy, Inc., is a major natural gas pipeline company. Northern Border is a publicly traded partnership with its units listed on the New York Stock Exchange. It is mainly engaged in the operation of several FERC-regulated gas pipeline systems, including interests in Northern Border Pipeline, Midwestern, and Viking.

Q. Have you prepared an exhibit showing the contributions of the various segments of each of your proxy companies to the company's income?

A. Yes. In Exhibit No. __(JPW-3), I show the contributions to a measure of the company income from the various segments of each proxy pipeline company. The income measure varies from company to company and is the one used by the company in its segment analysis.

Q. What conclusions do you draw from Exhibit No. __(JPW-3)?

A. It is clear from the exhibit that gas pipelines and storage are the major contributors to income for GulfTerra, KMI, and Northern Border.

Enterprise is heavily engaged in both gas and oil pipelines. It is difficult to determine the relative contributions of each from data in the company's annual reports. Enterprise owns 100% of Cypress and Acadian gas pipelines, 50% of Stingray, and smaller percentages of five other gas pipelines.

KMEP has for some years been used in rate cases as an oil pipeline proxy company, but the company has also been acquiring major gas pipelines, including Trailblazer. I conclude that KMEP is an appropriate proxy in both gas and oil pipeline rate cases.

Q. Is it true that four of your five proxy companies – Enterprise, GulfTerra, KMEP and Northern Border – are publicly traded master limited partnerships ("MLPs")?

A. Yes.

Q. Is there any reason for the Commission to reject the inclusion of MLPs in your set of proxy companies?

A. I believe not. While Algonquin is a corporation rather than a limited partnership, I believe it is significant that the Commission has relied in its most recent oil pipeline rate case decision exclusively on MLPs as proxy companies. *Mobil Oil Corp. v. SFPP, L.P.*, Opinion No. 435, 86 FERC ¶ 61,022 (1999). I do not believe that in any of its pipeline decisions the Commission has referred to differences between MLPs and corporations as a reason for disqualifying either of them for use as proxy companies. In Opinion No. 435, the Commission Staff recommended the use of both incorporated pipeline companies and MLPs as proxies in the same oil pipeline case, without drawing any distinction between the incorporated form and the limited partnership form. *Mobil Oil Corp. v. SFPP, L.P.*, Opinion No. 435, 86 FERC ¶ 61,022 (1999).

<u>Criteria to be Satisfied for the DCF Method</u>

Q. What criteria are to be used for the determination of the cost of common equity?

A. The Supreme Court has established the criteria in *Bluefield Water Works v. PSC*, 262 U.S. 679, 692-93 (1923), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944). The utility must be allowed a rate of return commensurate with returns on investments in other enterprises having corresponding risks, one that assures confidence in the utility's financial integrity and one that maintains its credit and enables it to attract capital.

Q. Do these criteria require a methodology that is based on measurement of actual investor expectations?

A. Yes. The regulated utility must be able to attract investment capital in a free and competitive capital market. It must offer investors the prospect of a competitive rate of return, and its allowed rate of return must therefore reflect investor expectations.

<u>Market Based DCF Model</u>

Q. The DCF model that you have set out in your testimony is:

$$k = (1+.5g)y + g$$

What is the basis for stating that the DCF model that you have described is "market based"?

A. The element *y* in the formula is the dividend yield actually available in the market place for a particular stock. It is, as I have stated above, the dividend per share, a known quantity for any particular stock, divided by the quoted market price of a share of stock, a known number and one established in a free market where shares are traded frequently. There is rarely any significant dispute over the value of *y* to be used in the DCF model in any particular case.

For the value of *g* to be market based, it must reflect the growth rate expected by the investment community for the particular company.

<u>Dividend Yield (*y*)</u>

Q. How did you determine the dividend yield for each of your proxy companies?

A. I averaged the high and low prices for each company over the most recent six months, and divided the average price into the annualized dividend to arrive at a yield for each company. The prices, dividends, and yields are shown in Exhibit No. __(JPW-4).

Q. Does the Commission generally favor the use of six-month averages to compute yields for use in the DCF model?

A. Yes. This was the conclusion in *Boston Edison Co.*, Opinion No. 299, 42 FERC ¶ 61,374 (1988) and *Blue Ridge Power Agency, et al.*, 55 FERC ¶ 61,509 (1991).

<u>Investor Expected Growth (*g*)</u>

Q. Is the determination of the value of *g* as straightforward as the determination of *y*?

A. No. There are practical difficulties in determining the market based growth rate *g*. First, not all investors may have the same growth expectation. Second, growth expectations may vary depending upon the length of the future period for which the growth rate is to apply, and there is no entirely objective way to determine the correct period for the market based growth rate to be used in the DCF method. In theory, the model I have described calls for a growth rate "to infinity." But as a practical matter, investors are not interested in expected growth to infinity. There is evidence that investors generally have little use for growth forecasts that purport to go beyond about five years, because such forecasts are believed unlikely to be reliable.

There are different sources of values for *g*. At one time witnesses in rate cases made extensive use of historical growth rates as predictors of future growth rates. Subsequently, published growth forecasts prepared by professional security analysts began to be available. These forecasts presumably incorporate all that can be learned from history plus the expertise of the analysts in judging the future for a particular company. Different analysts, of course, provide different forecasts, but there is generally a range of agreement.

Q. How, in your judgment, should the growth rate *g* be determined for use in the DCF equation?

A. First, it is important to note that the growth rate *g* is the growth rate expected by the market, that is, by investors as a whole. It is not necessarily a correct growth forecast; the market may be wrong. But the cost of common equity to a regulated enterprise depends upon what the market expects, not upon what is actually going to happen.

Since the DCF method requires the use of growth rates expected by investors, it is important to use the best evidence of the growth rates actually expected by the investment community. There is a body of empirical evidence showing that the most reliable measure of investor-expected growth rates for use in the DCF model is the set of growth forecasts published by professional security analysts.

IBES Growth Forecasts

Q. Please explain how you made use of IBES-reported growth forecasts.

A. IBES is a service sold by subscription. The FERC is one of the subscribers. IBES regularly collects five year earnings growth forecasts from about 2,400 security analysts for about 5,000 companies. The forecasts are tabulated and distributed monthly to subscribers. I made use of the earnings growth forecasts published on September 18, 2003, for my chosen proxy companies.

Q. Are the earnings growth forecasts reported by IBES strictly five-year forecasts?

A. IBES identifies them as "long-term growth" forecasts, although they are based on five year projections. So far as investors are concerned, I believe that a five-year forecast is regarded as "long-term."

Use of the Commission's Two-Stage Growth Model

Q. Please explain the Commission's two-stage growth DCF model.

A. The Commission appears to have been troubled in recent years by the question whether published growth forecasts satisfy the assumption of the DCF model that the value of *g* is the investor expectation for a long enough period to justify the model's use. As I have noted, in theory the model requires a growth expectation "to infinity." As a practical matter, there are no published forecasts of corporate earnings growth that purport to go beyond about five years.

The model the Commission has turned to is a two-stage growth model, making use of the IBES-reported earnings growth forecasts that I have discussed and also of the average of forecasts of long-term growth in GDP derived from three sources. Until 2001, the sources were the EIA, DRI/McGraw Hill, Inc. ("DRI"), and The WEFA Group ("WEFA"), the latter two of which are economic forecasting organizations. In 2001, DRI and WEFA combined to form Global Insight and now produce a single forecast. In Opinion No. 414-A, the Commission decided to give the short-term (IBES-reported) growth forecast a weight of two-thirds and the long-term (GDP) forecast a weight of one-third, because "long-term projections are inherently more difficult to make, and thus less reliable, than short-term projections." Opinion No. 414-A, 84 FERC at p. 61,423.

Q. In your judgment, does the Commission's two-stage model accurately reflect the process by which investors make the decision to buy or sell shares of stock?

A. I believe that the use of the two-stage growth forecast does not accurately reflect investor behavior, and that the Commission's method does not qualify as a true "market based" method.

Q. Did you nevertheless perform your analysis using the Commission's two-stage growth model?

A. Yes. The results are shown in Exhibit No. __(JPW-4).

Q. Please explain your exhibit.

A. To the dividend yields and the IBES-reported growth rates, I have added the GDP growth rate forecast as the Commission has prescribed. The mean of the two sources of long-term GDP growth forecasts is 5.87%. I have given a 2/3 weight to the IBES-reported earnings growth rate forecast and a 1/3 weight to the GDP growth rate forecast in arriving at weighted average growth rates.

The end result of the exhibit, for the set of proxy companies, is a mean and a median of 15.25%.

Q. What is your conclusion with respect to the cost of equity for gas pipelines at the present time?

A. I believe that on the basis of the analysis of five proxy companies, the cost of equity for gas pipelines is approximately 15.25%.

Cost of Equity for Manchester Street and Brayton Point Facilities

Q. You have said that Algonquin is proposing a cost of equity of 16% in this proceeding. Is 16% is a fair and reasonable cost?

A. I believe it is. In light of USGen's rejection of the pre-existing contracts that were to provide a means for payment, Algonquin's risk of recovering its costs for the Manchester Street and Brayton Point facilities is well above average. In his testimony, Mr. Richard J. Kruse discusses the special risks related to recovery of the costs of these facilities created by a conflict between the Commission's incremental rate policy and policies encouraging expanded rights and flexibility for customers receiving service under open access rate schedules. (See Exhibit No. __(RJK-1))

Q. Please explain briefly the nature of this risk.

A. Mr. Kruse describes these circumstances in detail in his testimony, and I am relying on his description as the factual basis for my conclusions. Mr. Kruse describes a policy environment that has evolved from one in which gas pipelines provided service that was strictly limited to terms set forth in contracts with customers to an environment in which certain contractual limitations have been largely eliminated. Under past Commission policy, certain customers, for example those served by incremental facilities, would enter into a contract that specified a route that could be used to serve specific receipt and delivery points. During the past decade, Commission policy has evolved so that these contractual rights and limitations are much less meaningful. Under current Commission policy, customers are given broad, flexible rights to access receipt and delivery points across the entire pipeline system. This access – at no extra cost to the customer – has tended to make contractual rights and limitations materially less meaningful. This change in Commission policy has created particular risks for companies with facilities that are incrementally priced. The ability of lower-cost system-wide services to be used to serve markets previously limited to service under incremental contracts creates both an opportunity and an incentive for customers to avoid the costs of the incremental facilities and to use the lower-cost service.

Under Algonquin's pre-October 10, 2003 tariff, shippers under the open access rate schedules had the ability to service markets previously limited to service under incremental contracts without payment of the associated rates. The tariff sheets effective October 10, 2003 restrict access to the Manchester Street and Brayton Point delivery points to those shippers paying the revised incremental AFT-1(X-38) or AFT-CL(X-37) rates. In addition, in light of USGen's rejection of its firm contracts, Algonquin has attempted to reflect a rate that will provide an opportunity to recover the cost of service on the incremental facilities. As Mr. Kruse indicates, however, it is unlikely that Algonquin will actually recover its costs. These circumstances have caused a significant increase in the risk associated with the recovery of the costs of the Manchester Street and Brayton Point facilities. Accordingly, the adjustment in the median 15.25% cost of equity resulting from the proxy group to the proposed 16% cost of equity is commensurate with this additional risk and the 16% cost of equity is reasonable.

Furthermore, the problems created by the policy conflict described by Mr. Kruse still exist with respect to other services on Algonquin.

Q. Does this conclude your testimony?

A. Yes. It does.

FINAL Professor Williamson testimony for RP04-24.DOC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the matter of)
Algonquin Gas Transmission Company) Docket No. RP04-24-000

Affidavit of J. Peter Williamson

J. Peter Williamson, being first duly sworn according to law, on oath deposes and says that he is the witness whose prepared direct testimony in the above entitled proceeding accompanies this affidavit; that if asked the questions which appear in the text of the aforesaid prepared testimony, affiant would give the answers that are therein set forth; and that affiant adopts the aforesaid testimony as his sworn, direct testimony in these proceedings.

J. Peter Williamson

Subscribed and sworn to before me this 28th day of November, 2003.

Notary Public

KATHERINE J. LUCIER, Notary Public
My Commission Expires September 15, 2004

EDUCATION, TEACHING, RESEARCH AND PROFESSIONAL EXPERIENCE OF J. PETER WILLIAMSON

Education

University of Toronto, B.A. in 1952, Mathematics, Physics & Chemistry; Harvard Business School, MBA in 1954, DBA in 1961; Harvard Law School LL.B. in 1957.

Teaching and Research

From 1957 to 1961, Assistant Professor of Business Administration at the Harvard Business School. In 1961 joined the faculty of the Amos Tuck School of Business Administration at Dartmouth College as Associate Professor. On the Amos Tuck School faculty since 1961 and Professor since 1966 (except for one year on the faculty of the University of Toronto Law School). Currently the Laurence F. Whittemore Professor of Finance, Emeritus, at the Amos Tuck School.

Teaching at the Amos Tuck School included courses in corporation finance, financial institutions, investments and federal taxation. Research in these fields has led to a dozen or so books and monographs and to articles in the *Journal of Finance*, the *Financial Analysts Journal*, the *Journal of the Eastern Financial Association*, the *Journal of Bank Research*, the *Journal of Portfolio Management* and other professional journals.

Consulting and Research

Consulting activity, in addition to work for regulated utilities, has included valuations of businesses, advice on investment portfolios and specifically on investment expectations; and several publications have been specifically concerned with investment strategies, risk and likely rates of return.

Author of four books that are largely concerned with this subject and a number of articles.

The book, *Performance Measurement and Investment Objectives for Educational Endowment Funds*, was published by the Common Fund in 1972. The book, *Funds for the Future*, published by the Twentieth Century Fund in 1975, consists chiefly of a discussion of investment of college and university endowment funds, including investment risk and expected rates of return. A revised and updated edition of this book, entitled *Funds for the Future: College Endowment Management for the 1990s*, was published by the Common Fund in 1993. The book, *Spending Policy for Educational Endowments*, co-authored with Richard Ennis of Ennis, Knupp & Gold, Inc., was published by the Common Fund in 1976. It deals with the relationship between spending plans and expectations of risk and return. Author of chapters in *The Handbook of Financial Markets and Institutions* (6th ed. 1986) and in *The Investment Manager's Handbook* (1980) entitled, respectively, "Performance Measurement" and "Educational Endowment Funds." Editor of, and author of two chapters in the *Investment Banking Handbook* published by John Wiley & Sons in 1988. Author of a chapter in the *Handbook of Modern Finance*, published by Warren Gorham Lamont in 1993.

Trustee of the Common Fund 1978-90, and Chairman of its Short-term Fund Committee. Participated as a trustee in the hiring, reviewing and replacement of over thirty investment managers who managed 5.5 billion dollars invested long-term. Worked more closely with three managers who managed another 4.5 billion dollars short-term funds of the Common Fund.

In 1966-67 and 1977-79, retained by the Canadian Government's Department of Consumer and Corporate Affairs to consider appropriate federal regulation of securities markets in Canada. One of four authors of *Proposals for a Securities Market Law for Canada* (1979) and the author of two working papers published as part of the *Proposals*: "Canadian Capital Markets" and "Canadian Financial Institutions."

Prepares summaries for publication of all the presentations made at the semi-annual seminars of the Institute for Quantitative Research in Finance and has done so for 27 years. The set of summaries for each seminar is published following the seminar, and in addition five volumes of summaries organized by topics have been published, covering 1976 through 2000.

Regulatory Proceedings

Has testified on behalf of a number of utilities and on behalf of several consumer representatives. Testified in 1980 on behalf of the Public Service Company of New Hampshire before the New Hampshire Board of Taxation in connection with the franchise tax paid by utilities in New Hampshire. Testified over the past 15 years in electric utility rate cases before the Vermont Public Service Board at the request of the Counsel for the Public, the Department of Public Service and the Public Service Board in connection with applications for rate increases filed by Green Mountain Power Corporation (Dockets 3642, 3758, 4418, 4503/4537, 4570, 4661, 4796, 4865, 5013 and 5125), Central Vermont Public Service Corporation (Dockets 3744, 3991, 4230, 4634 and 5030) and Vermont Electric Cooperative (Dockets 5009/5112 and 5630/5632), and on behalf of Green Mountain Power (Dockets 5282, 5370, 5428, 5780, 5983 and 6107).

Testified, at the request of the Vermont Public Service Board, on a proposed amendment by Central Vermont Public Service Corporation to its first mortgage bond indenture (Docket 4206), and on the proposals by Green Mountain Power and Central Vermont to purchase participations in the Seabrook nuclear plant in the summer of 1979. Also testified before the Board at the request of the Department of Public Service on a proposal by Central Vermont Public Service corporation to sell its participation in the Seabrook plant (Docket 5045). Testified at the request of Central Vermont Public Service Corporation on a proposal to classify its Board of Directors (Docket 5103), and at the request of the Vermont Electric Cooperative on a proposed restructuring of its debt (Docket 5630/5632).

Testified before the Rhode Island Public Utilities Commission at the request of the Rhode Island Division of Public Utilities and Carriers in connection with an application for rate relief made by Narragansett Electric Company (Docket 1288).

Testified before the New Hampshire Public Utilities Commission at the request of the New Hampshire Electric Cooperative in rate cases (Dockets DR 77-83, DR 78-24, DR 79-178, DR 80-189, DR 81-340 and DR 98-025) and in a financing case (Docket DF 83-360). Also testified before the New Hampshire PUC at the request of the Consumer Advocate on a petition for rate relief filed by Public Service Company of New Hampshire (Docket DR 79-187), at the request of Public Service Company of New Hampshire on its petitions for rate relief (Dockets DR 81-6, DR 81-87, DR 82-150, DR 82-333, DR 86-122 and DR 87-151), and at the request of EnergyNorth Natural Gas in its petition for rate relief (Docket DR91-212).

Testified before the California Public Utilities Commission at the request of SFPP, L.P., Complaint No. 97-04-025, January, 1998, and October, 2000.

Filed testimony with the Regulatory Commission of Alaska on behalf of TAPS Carriers, Case No. P-03-4, June 3, 2003.

Testified before the Federal Energy Regulatory Commission at the request of Public Service Company of New Hampshire in support of its rate increases (Docket Nos. ER81-659 and ER82-141). Also testified before the FERC at the request of Tennessee Gas Pipeline Co. (Docket Nos. RP80-97 and RP81-54), Midwestern Gas Transmission Co. (Docket Nos. RP81-17 and RP81-57), Tarpon Transmission Company (Docket No. RP84-82-000), Mountain Fuel Resources, Inc. (Docket No. RP86-7-000), Alabama-Tennessee Natural Gas Company (Docket No. RP87-41-000), Kern River Gas Transmission Company (Docket No. CP85-437-000), ANR Pipeline Company (Docket No. RP89-161), Tarpon Transmission Company (Docket No. RP84-82-004), Lakehead Pipeline Company L.P. (Docket No. IS92-27-000), Kern River Gas Transmission Company (Docket No. RP92-226-000), Wyoming Interstate Company, Ltd. (Docket No. RP85-39-

000), Ozark Gas Transmission System (Docket No. RP94-105-000), Williams Natural Gas Company (Docket No. RP93-109-000), Southern Natural Gas Company (Docket No. RP93-15-000), Transcontinental Gas Pipe Line Corp. (Docket No. RP95-197), ANR Pipeline Company (Docket No. RP94-43-000), SFPP, L.P. (Docket No. OR92-8-000), Ocean State Power (Docket Nos. ER97-1899 and -1890), Transcontinental Gas Pipe Line (Docket No. RP97-71), Stingray Pipeline Company (Docket No. RP99-166-000), Arco Products Co., et al. v. SFPP, L.P. (Docket No. OR96-2-000), Trailblazer Pipeline Company (RP03-162-000), and High Island Offshore System, L.L.C. (RP03-221-000).

Testified before the Public Service Commission of Utah in Mountain Fuel Supply and Questar Gas Company (Cases Nos. 89-057-15 and 02-057-02).

Filed testimony with the State of New York Public Service Commission in Empire State Pipeline, Case No. ____ (9/30/95).

Filed testimony with the Michigan Public Service Commission at the request of Dominion Midwest Energy, Inc., in Case No. U-12342, March 2000.

Prepared and filed testimony in rate cases before the FERC that have not involved hearings either because of settlements or because hearings have not yet been scheduled in: United Gas Pipe Line Company (Docket No. RP88-92), Questar Pipeline Company (Docket No. RP88-93), Natural Gas Pipeline Company of America (Docket No. RP88-209), Tennessee Gas Pipeline Company (Docket No. RP88-228), High Island Offshore System (Docket No. RP89-37), U-T Offshore System (Docket No. RP89-38), Southern Natural Gas Company (Docket Nos. RP89-224 and 90-139), South Georgia Natural Gas Company (Docket No. RP89-225), Alabama-Tennessee Natural Gas Company (Docket No. RP89-251), Transcontinental Gas Pipe Line (Docket No. RP90-8), Colorado Interstate Gas Company (Docket No. RP90-69), East Tennessee Natural Gas Company (Docket No. RP90-111), New England Hydro-Transmission Electric Company Inc., New England Hydro-Transmission Corporation (Docket No. ER90-450), New England Power Co. (Docket No. ER90-525), United Gas Pipe Line Company (Docket No.

RP91-126), Questar Pipeline Company (Docket No. RP91-140-000), Williams Natural Gas Company (Docket No. RP-91-152-000), Ocean State Power II (Docket No. ER89-563), New England Power Co. (Docket No. ER91-565-000), Midwestern Gas Transmission Company (Docket No. RP91-189-000), Tennessee Gas Pipeline Co. (Docket No. RP91-203-000), East Tennessee Natural Gas Company (Docket No. RP91-204-000), High Island Offshore System (Docket No. RP92-50-000), U-T Offshore System (Docket No. RP92-47-000), Viking Gas Transmission Company (Docket No. RP92-48-000), South Georgia Natural Gas Co. (Docket No. RP92-74-000), Southern Natural Gas (Docket No. RP92-134-000), New England Power Co. (Docket No. ER92-764-000), Tennesee Gas Pipeline Company (Docket No. RP91-203-000), United Gas Pipe Line Company (Docket No. RP92-235-000), Alabama-Tennessee Natural Gas Company (Docket No. RP92-237-000), Natural Gas Pipeline Company of America (Docket No. RP93-36-000), U-T Offshore System (Docket No. RP93-59-000), High Island Offshore System (Docket No. RP93-61-000), Trailblazer Pipeline Company (Docket No. RP93-55-000), Colorado Interstate Gas Company (Docket No. RP93-99-000), Texas Gas Transmission Company (Docket No. RP93-106-001), New England Power Company (Docket No. ER93-920-000), Lakehead Pipeline Company (Docket No. IS93-33), Massachusetts Electric Company (Docket No. ER94-129), U-T Offshore System (Docket No. RP93-61-000), High Island Offshore System (Docket No. RP93-59-000), Overthrust Pipeline Co. (Docket No. RP94-104-000), U-T Offshore System (Docket No. RP94-161-000), High Island Offshore System (Docket No. RP94-162), Wyoming Interstate Co., Ltd. (Docket No. RP94-267-000), Vermont Yankee Nuclear Power (Docket No. ER94-), New England Power Company (Docket No. ER95-267-000), Stingray Pipeline Company (Docket No. RP94-301-000), Texas Gas Transmission Corp.(Docket No. 94-423-000), Florida Gas Transmission Company (Docket No. 95-103-000), Tennessee Gas Pipeline Company (Docket No. RP95-112-000), Williams Natural Gas Company (Docket No. RP95-136-000), Northern Natural Gas (Docket No. RP95-185), Natural Gas Pipeline Company of America (Docket No. RP95-326-000), Questar Pipeline Company (Docket No. RP95-407-000), Ocean State Power (Docket Nos. ER95-533-001 and ER95-530-001), Colorado Interstate Gas Co., (Docket No. RP96-190-000), Ozark Gas Transmission System (Docket No. RP96-189-000), Mississippi River Transmission

Corp., (Docket No. RP96-199-000), Florida Gas Transmission Company (Docket No. RP96-366 -000), Transcontinental Gas Pipe Line Corp. (Docket No. RP97-71-000), Sea Robin Pipeline Company (Docket No. RP95-167-000), Texas Gas Transmission Corp (Docket No. RP97-344-000), Wyoming Interstate Co., Ltd. (Docket No. RP97- 375-000), Trailblazer Pipeline Company (Docket No. RP97-408-000), Northern Natural Gas Company (Docket No. RP98-203-000), Southern Natural Gas Company (Docket No. RP99-496-000), Texas Gas Transmission Corporation (Docket No. RP00-260-___), Mojave Pipeline Company (Docket No. RP01-172-.000), Transcontinental Gas Pipe Line Corp. (Docket No. RP01-245-000), Canyon Creek Compression Company (RP02-___-___), Cove Point LNG Limited Partnership (RP01-217-001, Pine Needle LNG Company LLC (RP02-407-000), and BP Transportation (Alaska) Inc. (IS01-504-000).

Testified three times before the Ontario Securities Commission, once in July 1982 in hearings on diversification in the Canadian securities industry, again in June 1983 in hearings on the entry of banks into the brokerage business, and again in December 1984 in hearings on ownership of securities firms.

Segment Analysis for AGT

Segment EBIT/Operating Income
Company Proxy Group

	Year	Total	Fraction-ation	Pipelines	Processing	Octane Enhancement	Other	Fraction-ation	Pipelines As %	Processing As %	Octane Enhancement As %	Other As %	Total Percent
1 Enterprise Products Operating Margin	2002	332627	129000	214932	-17633	8569	-2241	38.78%	64.62%	-5.30%	2.58%	-0.67%	100.00%
	2001	376783	118610	96569	154989	5671	944	31.48%	25.63%	41.13%	1.51%	0.25%	100.00%
	2000	320615	129376	56099	122240	10407	2493	40.35%	17.50%	38.13%	3.25%	0.78%	100.00%
		Total EBIT	Nat Gas Pipelines & Plants	Nat Gas Storage	Oil/Gas NGL	Platform Services	Other	Nat Gas Pipelines As % Of Total	Nat Gas Storage As % Of Total	Oil/Gas NGL As % Of Total	Platform Services As % Of Total	Other As % Of Total	
2 Gulfterra EBIT	2002	176046	121371	8126	34507	18863	-6821	68.94%	4.62%	19.60%	10.71%	-3.87%	100.00%
	2001	95594	27413	7604	38445	20122	2010	28.68%	7.95%	40.22%	21.05%	2.10%	100.00%
	2000	67264	36987	2193	21322	22491	-15729	54.99%	3.26%	31.70%	33.44%	-23.38%	100.00%
		Total	Nat Gas Pipelines	Product Pipelines	CO2 Pipelines	Terminals		Nat Gas Pipelines As %	Product Pipelines As %	CO2 Pipelines As %	Terminals As %		
3 KMEP Operating Income	2002	843155	253498	342372	66560	180725		30.07%	40.61%	7.89%	21.43%		100.00%
	2001	673121	171899	298991	59559	142672		25.54%	44.42%	8.85%	21.20%		100.00%
	2000	379988	97349	195057	48059	39523		25.62%	51.33%	12.65%	10.40%		100.00%
		Total	Nat'l Gas Pipeline of America	TransColorado Pipeline	Kinder Morgan Retail	Kinder Morgan Texas Pipeline	Power & Other	Nat'l Gas Pipeline of America As %	TransColorado Pipeline As %	Kinder Morgan Retail As %	Kinder Morgan Texas Pipeline As %	Power & Other As %	
4 Kinder Morgan Inc. Segment Earnings	2002	473288	359911	12648	64056		36,673	76.04%	2.67%	13.53%	0.00%	7.75%	100.00%
	2001	463980	346569	-5268	56696		65,983	74.69%	-1.14%	12.22%	0.00%	14.22%	100.00%
	2000	448314	344405	-10336	47705	29318	37,222	76.82%	-2.31%	10.64%	6.54%	8.30%	100.00%
		Total	Interstate Natural Gas Pipelines	Gas Gathering & Processing	Coal Slurry	Other		Interstate Natural Gas Pipelines As %	Gas Gathering & Processing As %	Coal Slurry As %	Other As %		Total Percent
5 Northern Border Operating Income	2002	224981	200584	24900	5054	-5557		89.16%	11.07%	2.25%	-2.47%		100.00%
	2001	220959	199822	18239	5953	-3055		90.43%	8.25%	2.69%	-1.38%		100.00%
	2000	188302	184167	2019	4355	-2239		97.80%	1.07%	2.31%	-1.19%		100.00%

Sources for Exhibit No. ____ (JPW-3)

Enterprise
Products
Partners L.P.

2002 ANNUAL REPORT

ORGANIC · STRATEGIC · GEOGRAPHIC ·

DISCIPLINED EXPANSION

The following table shows our measurement of total gross operating margin for the periods indicated (dollars in thousands):

	For Year Ended December 31, 2002	2001	2000
Revenues *(1)*	$ 3,584,783	$ 3,154,369	$ 3,049,020
Operating costs and expenses *(1)*	(3,382,561)	(2,861,743)	(2,801,060)
Equity in income of unconsolidated affiliates *(2)*	35,253	25,358	24,119
Subtotal	237,475	317,984	272,079
Add: Depreciation and amortization in operating costs and expenses *(3)*	86,029	48,775	35,621
Retained lease expense, net in operating costs and expenses *(4)*	9,124	10,414	10,645
(Gain) loss on sale of assets in operating costs and expenses *(3)*	(1)	(390)	2,270
Total segment gross operating margin	$ 332,627	$ 376,783	$ 320,615

(1) Amounts are comprised of both third party and related party totals from the Statements of Consolidated Operations and Comprehensive Income
(2) Amount taken from Statements of Consolidated Operations and Comprehensive Income
(3) Amount taken from Statements of Consolidated Cash Flows
(4) Amount represents leases paid by EPCO and the related contribution by the minority interest as reflected on the Statements of Consolidated Cash Flows

Our measurement of gross operating margin amounts by segment along with a reconciliation to consolidated operating income were as follows for the periods indicated (dollars in thousands):

	For Year Ended December 31, 2002	2001	2000
Gross operating margin by segment:			
Pipelines	$ 214,932	$ 96,569	$ 56,099
Fractionation	129,000	118,610	129,376
Processing	(17,633)	154,989	122,240
Octane enhancement	8,569	5,671	10,407
Other	(2,241)	944	2,493
Total segment gross operating margin	332,627	376,783	320,615
Depreciation and amortization	(86,029)	(48,775)	(35,621)
Retained lease expense, net	(9,124)	(10,414)	(10,645)
Gain (loss) on sale of assets	1	390	(2,270)
Selling, general and administrative expenses	(42,890)	(30,296)	(28,345)
Consolidated operating income	$ 194,585	$ 287,688	$ 243,734

GulfTerra Energy Partners, L.P.

Formerly known as El Paso Energy Partners, L.P.

2002 Annual Report

Reconciliation of EBITDA by Segment

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other[1]	Total
			(In thousands)			
The Year Ended December 31, 2002						
Net income						$ 97,688
Plus: Interest and debt expense[1]						83,494
Less: Income from discontinued operations						5,136
EBIT	$ 121,371	$ 34,507	$ 8,126	$ 18,863	$ (6,821)	176,046
Plus: Depreciation, depletion and amortization	44,479	6,481	8,503	4,205	8,458	72,126
Cash distributions from unconsolidated affiliates	2,000	15,804	—	—	—	17,804
Net cash payment received from El Paso Corporation	—	—	—	—	7,745	7,745
Discontinued operations of Prince facilities	—	—	—	6,156	1,045	7,201
Less: Earnings from unconsolidated affiliates	194	13,445	—	—	—	13,639
Noncash hedge gain	411	—	—	—	—	411
EBITDA[2]	$ 167,245	$ 43,347	$ 16,629	$ 29,224	$ 10,427	$ 266,872
Year Ended December 31, 2001						
Net income						$ 55,149
Plus: Interest and debt expense[1]						41,542
Less: Income from discontinued operations						1,097
EBIT	$ 27,413	$ 38,445	$ 7,604	$ 20,122	$ 2,010	95,594
Plus: Depreciation, depletion and amortization	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge	3,921	—	—	—	—	3,921
Cash distributions from unconsolidated affiliates	12,850	22,212	—	—	—	35,062
Net cash payment received from El Paso Corporation	—	—	—	—	7,426	7,426
Discontinued operations of Prince facilities	—	—	—	5,889	672	6,561
Loss on sale of Gulf of Mexico assets	7,793	—	—	4,058	—	11,851
Less: Earnings (loss) from unconsolidated affiliates	(9,761)	18,210	—	—	—	8,449
Non-cash earnings related to future payments from El Paso Corporation	21,964	—	—	3,440	—	25,404
EBITDA[2]	$ 52,152	$ 47,560	$ 13,209	$ 30,783	$ 17,636	$ 161,340

[1] We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

[2] EBITDA is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

Reconciliation of EBITDA by Segment

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other[1]	Total
			(In thousands)			
The Year Ended December 31, 2000						
Net income						$ 20,497
Plus: Interest and debt expense[1]						46,820
Less: Income from discontinued operations						(252)
Income tax benefit						305
EBIT	$ 36,987	$ 21,322	$ 2,193	$ 22,491	$ (15,729)	67,264
Plus: Depreciation, depletion and amortization	8,062	1,391	1,868	4,445	11,977	27,743
Cash distributions from unconsolidated affiliates	20,428	13,532	—	—	—	33,960
Insurance proceeds	—	5,000	—	—	—	5,000
Less: Earnings from unconsolidated affiliates	10,213	12,718	—	—	—	22,931
Litigation resolution	—	—	—	2,250	—	2,250
Hedging activities	—	—	—	—	1,619	1,619
Gain on sale of assets	158	—	—	—	—	158
EBITDA[2]	$ 55,106	$ 28,527	$ 4,061	$ 24,686	$ (5,371)	$ 107,009

[1] We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

[2] EBITDA is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

KINDER MORGAN
ENERGY PARTNERS, L.P.

2002 ANNUAL REPORT

KMEP

Financial information by segment follows (in thousands):

	2002	2001	2000
Revenues			
Products Pipelines	$ 576,542	$ 605,392	$420,272
Natural Gas Pipelines	3,086,187	1,869,315	174,187
CO^2 Pipelines	146,280	122,094	89,214
Terminals	428,048	349,875	132,769
Total consolidated revenues	$4,237,057	$2,946,676	$816,442
Operating income			
Products Pipelines	$ 342,372	$ 298,991	$195,057
Natural Gas Pipelines	253,498	171,899	97,349
CO^2 Pipelines	66,560	59,559	48,059
Terminals	180,725	142,672	39,523
Total segment operating income	843,155	673,121	379,988
Corporate administrative expenses	(118,857)	(109,293)	(64,427)
Total consolidated operating income	$ 724,298	$ 563,828	$315,561
Earnings from equity investments, net of amortization of excess costs			
Products Pipelines	$ 25,717	$ 22,686	$ 29,105
Natural Gas Pipelines	23,610	21,156	14,975
CO^2 Pipelines	34,311	31,981	19,328
Terminals	45	—	—
Consolidated equity earnings, net of amortization	$ 83,683	$ 75,823	$ 63,408
Interest revenue			
Products Pipelines	$ —	$ —	$ —
Natural Gas Pipelines	—	—	—
CO^2 Pipelines	—	—	—
Terminals	—	—	—
Total segment interest revenue	—	—	—
Unallocated interest revenue	1,819	4,473	3,818
Total consolidated interest revenue	$ 1,819	$ 4,473	$ 3,818
Interest (expense)			
Products Pipelines	$ —	$ —	$ —
Natural Gas Pipelines	—	—	—
CO^2 Pipelines	—	—	—
Terminals	—	—	—
Total segment interest (expense)	—	—	—
Unallocated interest (expense)	(178,279)	(175,930)	(97,102)
Total consolidated interest (expense)	$ (178,279)	$ (175,930)	$(97,102)
Other, net(a)			
Products Pipelines	$ (14,000)	$ 440	$ 10,492
Natural Gas Pipelines	36	749	744
CO^2 Pipelines	112	547	741
Terminals	15,550	226	2,607
Total consolidated Other, net	$ 1,698	$ 1,962	$ 14,584

(a) 2002 amounts include non-recurring environmental expense adjustments resulting in a $15.7 million loss to our Products Pipelines business segment and a $16.0 million gain to our Terminals business segment.

KINDER MORGAN INC.

2002 ANNUAL REPORT

Business Segment Information

	Year Ended December 31, 2002					December 31, 2002
	Segment Earnings	Revenues From External Customers	Intersegment Revenues	Depreciation And Amortization	Capital Expenditures	Segment Assets
	(In thousands)					
Natural Gas Pipeline Company of America	$ 359,911	$ 699,998	$ —	$ 87,305	$132,026	$ 5,629,355
TransColorado Pipeline(1)	12,648	7,725	93	1,062	325	258,627
Kinder Morgan Retail	64,056	259,748	—	15,044	25,395	406,797
Power and Other	36,673	47,784	—	3,085	17,207	389,596
Segment Totals	473,288	$1,015,255	$ 93	$106,496	$174,953	6,684,375
Earnings from Investment in Kinder Morgan Energy Partners	392,135					
General and Administrative Expenses	(73,496)					
Other Income and (Expenses)	(346,848)					
Income from Continuing Operations Before Income Taxes	$ 445,079					

	Segment Assets
Segment Totals	6,684,375
Investment In Kinder Morgan Energy Partners	2,034,160
Goodwill	990,878
Other(3)	393,337
Consolidated	$10,102,750

	Year Ended December 31, 2001					December 31, 2001
	Segment Earnings (Loss)	Revenues From External Customers	Intersegment Revenues	Depreciation And Amortization	Capital Expenditures	Segment Assets
	(In thousands)					
Natural Gas Pipeline Company of America	$ 346,569	$ 646,804	$ —	$ 85,843	$ 88,045	$ 5,598,239
TransColorado Pipeline(1)	(5,268)	—	—	—	—	134,256
Kinder Morgan Retail	56,696	290,300	44	12,590	35,629	380,339
Power and Other	65,983	117,803	2,029	7,247	497	327,821
Segment Totals	463,980	$1,054,907	$2,073	$105,680	$124,171	6,440,655
Earnings from Investment in Kinder Morgan Energy Partners	251,860					
General and Administrative Expenses	(73,319)					
Other Income and (Expenses)	(235,285)					
Income from Continuing Operations Before Income Taxes	$ 407,236					

	Segment Assets
Segment Totals	6,440,655
Investment In Kinder Morgan Energy Partners	1,772,027
Goodwill	1,055,767
Other(3)	244,672
Consolidated	$ 9,513,121

	Year Ended December 31, 2000					December 31, 2000
	Segment Earnings (Loss)	Revenues From External Customers	Intersegment Revenues	Depreciation And Amortization	Capital Expenditures	Segment Assets
	(In thousands)					
Natural Gas Pipeline Company of America	$ 344,405	$ 622,020	$(18)	$ 84,975	$49,771	$5,486,880
TransColorado Pipeline(1)	(10,336)	—	—	—	—	34,824
Kinder Morgan Retail	47,705	235,209	(1)	11,904	19,008	377,384
Kinder Morgan Texas Pipeline(2)	29,318	1,747,499	—	2,211	16,734	—
Power and Other	37,222	74,228	4	6,917	141	230,399
Discontinued Operations	—	—	—	—	3,185	—
Segment Totals	448,314	$2,678,956	$ (15)	$106,007	$88,839	6,129,487
Earnings from Investment in Kinder Morgan Energy Partners	113,320					
Investment In Kinder Morgan Energy Partners						661,644
Goodwill						1,180,097
Other(3)						425,450
General and Administrative Expenses	(59,799)					
Other Income and (Expenses)	(194,669)					
Consolidated						$8,396,678
Income from Continuing Operations Before Income Taxes	$ 307,166					

(1) We purchased the remaining 50% of this entity effective October 1, 2002. Prior to October 1, 2002 we accounted for our TransColorado investment under the equity method of accounting. Accordingly, the results presented represent a 50% equity interest prior to October 1, 2002 and a 100% consolidated interest thereafter

(2) Kinder Morgan Texas Pipeline was transferred to Kinder Morgan Energy Partners effective December 31, 2000.

(3) Includes, as applicable to each particular year, market value of derivative instruments (including interest rate swaps), income tax receivables and miscellaneous Corporate assets (such as information technology and telecommunications equipment) not allocated to individual segments.

Geographic Information

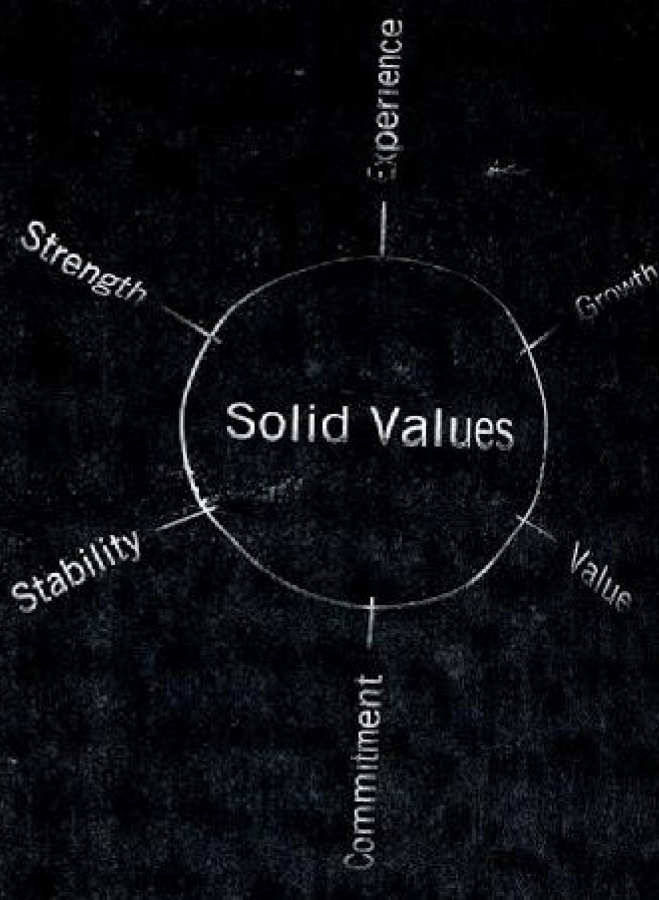
All but an insignificant amount of our assets and operations are located in the continental United States.

21. Recent Accounting Pronouncements

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* The provisions of this statement related to the rescission of FASB Statement No. 4 are effective for fiscal years beginning after May 15, 2002, the provisions related to FASB Statement No. 13 are effective for transactions occurring after May 15, 2002, and all other provisions of this statement are effective for financial statements issued on or after May 15, 2002. The principal effect of this statement on our reporting is that, beginning with reporting for 2003, previously recorded extraordinary losses on early retirement of debt, as well as any such future losses, will not be classified as extraordinary items but will, instead, be reported as part of income from continuing operations and separately described, if material.

Northern Border Partners, L.P.

2002 Annual Report



ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per unit, other financial data and operating data)

The following table sets forth, for the periods and at the dates indicated, selected historical financial data for us. The selected consolidated financial information should be read in conjunction with the Consolidated Financial Statements and the Notes and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," which are included elsewhere in this report.

	Year Ended December 31,				
	2002	2001[2]	2000[3]	1999	1998
Income Data:					
Operating revenues, net	$ 495,617	$ 461,469	$ 339,732	$ 318,963	$ 217,592
Product purchases	50,648	39,699	—		—
Operations and maintenance	111,668	96,449	62,097	53,451	44,770
Depreciation and amortization	75,874	76,310	60,699	54,842	43,885
Taxes other than income	32,446	28,052	28,634	30,952	22,012
Regulatory credit	—	—	—	—	(8,878)
Operating income	224,981	220,959	188,302	179,718	115,803
Interest expense, net	82,898	89,908	81,495	67,709	30,922
Other income	14,409	86	8,032	4,562	13,208
Minority interests in net income	42,816	42,138	38,119	35,568	30,069
Net income before extraordinary items	113,676	88,999	76,720	81,003	68,020
Extraordinary loss from debt restructuring	—	(1,213)	—	—	—
Net income to partners	$ 113,676	$ 87,786	$ 76,720	$ 81,003	$ 68,020
Net income per unit	$ 2.44	$ 2.12	$ 2.50	$ 2.70	$ 2.27
Number of units used in computation	42,709	38,538	29,665	29,347	29,345
Cash Flow Data:					
Net cash provided by operating activities	$ 243,142	$ 233,948	$ 169,615	$ 173,368	$ 103,849
Capital expenditures	49,874	126,414	19,721	102,270	652,194
Acquisition of businesses	1,561	345,074	229,505	31,895	—
Distribution per unit	3.20	2.99	2.65	2.44	2.30
Balance Sheet Data (at end of year):					
Property, plant and equipment, net	$ 2,015,280	$ 2,040,099	$ 1,732,076	$1,745,356	$ 1,730,476
Total assets	2,725,495	2,687,355	2,082,720	1,863,437	1,825,766
Long-term debt, including current maturities	1,403,743	1,423,227	1,171,962	1,031,986	976,832
Minority interests in partners' equity	242,931	250,078	248,098	250,450	253,031
Partners' equity	944,035	914,958	572,274	515,269	507,426
Other Financial Data:					
Ratio of earnings to fixed charges[1]	2.8	2.5	2.4	2.7	3.0
Operating Data:					
Interstate Natural Gas Pipeline Segment:					
Million cubic feet of gas delivered	935,654	891,935	852,674	834,833	608,187
Average daily throughput (mmcfd)	2,636	2,605	2,400	2,353	1,706
Natural Gas Gathering and Processing Segment:					
Gathering (mmcfd)	1,089	793	397	—	—
Processing (mmcfd)	127	118	—	—	—
Coal Slurry Pipeline Segment:					
Thousands of tons of coal shipped	4,639	4,932	4,711	4,494	4,489

(1) "Earnings" means the sum of pre-tax income from continuing operations (before adjustment for minority interests in consolidated subsidiaries or income from equity investees), fixed charges, amortization of capitalized interest and distributions from equity investees, less capitalized interest and the minority interests in pre-tax income of subsidiaries that have not incurred fixed charges. "Fixed charges" means the sum of (a) interest expensed and capitalized; (b) amortized premiums, discounts and capitalized expenses related to indebtedness; and (c) an estimate of interest within rental expenses.

(2) Includes results of operations for Bear Paw Energy (March 2001), Midwestern Gas Transmission (May 2001) and Border Midstream Services (April 2001) since dates of acquisition.

(3) Includes results of operations for Crestone Energy Ventures and Crestone Gathering Services, L.L.C. since date of acquisition in September 2000. The gathering activities of Crestone Gathering have been integrated with those of Bear Paw Energy.

AGT

Dividend Yields for Five Natural Gas Pipeline Companies

Monthly High and Low Stock Prices

Company	Tkr	April 2003 High	April 2003 Low	May 2003 High	May 2003 Low	June 2003 High	June 2003 Low	July 2003 High	July 2003 Low	August 2003 High	August 2003 Low	September 2003 High	September 2003 Low	Avg Price	Annual Divd	Yield
Enterprise Products Partners	EPD	23.10	20.62	24.65	21.40	23.32	22.01	24.10	20.31	22.44	20.76	22.86	21.89	22.29	1.49	6.69%
Gulfterra Energy	GTM	34.75	30.96	37.44	33.90	38.00	36.07	39.21	37.04	39.88	37.40	40.47	39.00	37.01	2.84	7.67%
Kinder Morgan Energy Partners	KMP	40.28	37.10	39.99	35.00	40.20	38.50	41.13	39.25	40.69	38.65	43.06	40.20	39.50	2.64	6.68%
Kinder Morgan Inc.	KMI	48.07	44.00	51.05	45.89	56.91	51.40	54.97	52.57	54.19	52.83	54.67	51.46	51.50	1.60	3.11%
Northern Border Partners LP	NBP	40.84	38.10	41.99	38.78	42.33	40.55	44.07	41.55	43.98	40.50	44.00	41.88	41.55	3.20	7.70%

Yield Plus Growth Using IBES Earnings Growth and GDP Gowth Forecasts

Alternative Calculation using Continuous and Discrete Yields

Company	Tkr	Dividend Yield	IBES Median	Second Stage Growth (GDP)	Weighted Average Growth	Adjusted Dividend Yield	Yield Plus Growth	Continuou Yield	Discrete Yield	Average Yield	Yield Plus Growth
Enterprise Products Partners	EPD	6.69%	10.00%	5.87%	8.62%	6.97%	15.60%	6.69%	7.26%	6.97%	15.60%
Gulfterra Energy	GTM	7.67%	8.00%	5.87%	7.29%	7.95%	15.24%	7.67%	8.23%	7.95%	15.24%
Kinder Morgan Energy Partners	KMP	6.68%	10.00%	5.87%	8.62%	6.97%	15.59%	6.68%	7.26%	6.97%	15.59%
Kinder Morgan Inc.	KMI	3.11%	15.00%	5.87%	11.96%	3.29%	15.25%	3.11%	3.48%	3.29%	15.25%
Northern Border Partners LP	NBP	7.70%	7.00%	5.87%	6.62%	7.96%	14.58%	7.70%	8.21%	7.96%	14.58%
Mean							15.25%				15.25%
Medians							**15.25%**				**15.25%**
High							15.60%				15.60%
Low							14.58%				14.58%

Source: IBES Report of 9/18/03

GDP Growth Forecast from EIA of 1/2003, and Global Insight (formerly DRI -WEFA) of 11/2002

Sources for Exhibit No. ____ (JPW-4)

Divd $ | Declared | Ex-Date | Stk. Record | CUSIP Payable

EMI GROUP PLC
◇ *SPONSORED ADR NEW np — 268694 205
Rate - None Pd'03-0.26864 '02-0.2644
c0.16922 — Sep 03 Sep 05 Oct 10
*Represents 2 Ord shs
cFree of British tax

EMPIRE DIST ELEC CO
■ COM p$1 — 291641 108
Rate - 0.32Q Pd'03-1.28 '02-1.28
0.32 Oct 23 Nov 26 Dec 01 Dec 15

EMPIRE LTD
PFD SER 2 VARIABLE RATE np TOR — 291843 704
Rate - Q-Amts Pd'03-0.87 '02-0.79
g0.22 Oct 01 Oct 10 Oct 15 Oct 31

ENBRIDGE ENERGY MGMT L L C
■ SHS UNITS REPSTG LTD LIABILITY np — 29250X 103
Rate - Q-Amts Pd'03- Stk '02-0.90
* Stk Oct 22 Oct 31 Nov 04 Nov 14
*Payable in additional shs. Cash equivalent $0.925.

ENBRIDGE ENERGY PARTNERS L P
■ COM np — 29250R 106
Rate - 0.925Q Pd'03-3.70 '02-3.60
*0.925 Oct 22 Oct 31 Nov 04 Nov 14
*Limited Partnership distribution.

ENBRIDGE INC
COM np TOR — 29250N 105
Rate - 0.415Q Pd'03-1.66 '02-1.52
g0.415 Oct 31 Nov 12 Nov 14 Dec 01
PREF SHS SER A 5.50% np TOR — 204
Rate - 0.34375Q Pd'03-1.375 '02-1.375
g0.34375 Oct 31 Nov 12 Nov 14 Dec 01
PFD SECS 7.60% np TOR — 303
Rate - 0.475Q Pd'03-1.425 '02-1.90
g0.475 Sep 02 Sep 10 Sep 15 Sep 30
PFD SECS 8% np TOR — 402
Rate - 0.50Q Pd'03-1.50 '02-2.00
g0.50 Sep 02 Sep 10 Sep 15 Sep 30
PFD SECS 7.80% np TOR — 501
Rate - 0.4875Q Pd'03-1.4625 '02-1.6976
g*0.4875 Sep 02 Sep 10 Sep 15 Sep 30
*Interest Payment

ENBRIDGE INCOME FD
ORDINARY TR UNIT p10 (Cdn) TOR — 29251D 106
Rate - 0.06875M Pd'03-0.275 '02- None
g0.06875 Oct 20 Oct 29 Oct 31 Nov 14

ENCANA CORP
COM np TOR — 292505 104
Rate - 0.10Q Pd'03-0.40 '02-0.40
g0.10 Oct 28 Dec 10 Dec 12 Dec 31

ENERGEN CORP
■ COM p$0.01 — 29265N 108
Rate - 0.185Q Pd'03-0.73 '02-0.71
0.185 Oct 29 Nov 12 Nov 14 Dec 01

ENERGY EAST CAP TR I
■ CAP SECS 8.25% 8.25% np — 29267G 200
Rate - 0.515625Q Pd'03-2.0625 '02-2.0625
†0.515625 Oct 07 Oct 28 Oct 30 Oct 31
†Interest Payment

ENERGY EAST CORP
■ COM p$6.66 2/3 ✥ — 29266M 109
Rate - 0.25Q Pd'03-1.00 '02-0.96
0.25 Oct 16 Oct 24 Oct 28 Nov 15

ENERGY SVGS INCOME FD
UNITS np TOR — 292717 105
Rate - M-Amts Pd'03-1.1618 '02- new-0.3831: old-1.16855 & Stk
g0.125 Oct 02 Oct 10 Oct 15 Oct 31

ENERPLUS RES FD
■ TR UNIT SER G NEW np — 29274D 604
Rate - M-Amts Pd'03-3.89 '02-3.25
g0.37 Sep 30 Oct 08 Oct 10 Oct 20
g0.35 Oct 30 Nov 06 Nov 10 Nov 20

ENERVEST DIVERSIFIED INCOME TR
TR UNIT np TOR — 292963 105
Rate - M-Amts Pd'03-0.77 '02-0.84
g0.07 Oct 21 Oct 29 Oct 31 Nov 14

ENGELHARD CORP
■ COM p$1 (I) — 292845 104
Rate - 0.11Q Pd'03-0.41 '02-0.40
0.11 Oct 02 Dec 11 Dec 15 Dec 31

ENNIS BUSINESS FORMS INC
■ COM p$2.50 — 293389 102
Rate - 0.155Q Pd'03-0.62 '02-0.62
0.155 Oct 07 Oct 10 Oct 15 Nov 03

ENRON CORP
◇ 2ND PFD CONV ADJ p$1 — 293561 601
Rate - Q-Amts '03- None '02- None
Arrears Oct 2 '03 - $23.891

ENRON CORP (cont.)
◇ aEXCHANGEABLE NT EXCHANGEABLE np — 293561 882
Rate - None '03- None '02- None
Arrears Oct 30 '03 - $3.115
aExchangeable into Com shs of Enron Oil & Gas

ENTERGY ARK INC
■ 1ST MTG BD 6% p$25 — 29364D 795
Rate - 0.375Q Pd'03-1.4542 '02- None
†0.375 Oct 07 Oct 29 Oct 31 Nov 03
†Interest Payment

ENTERGY CORP NEW
■ COM np (U) — 29364G 103
Rate - 0.45Q Pd'03-1.60 '02-1.34
0.45 Oct 31 Nov 07 Nov 12 Dec 01

ENTERGY GULF STS INC
■ PFD SER 1944 $4.40 p$100 — 29364L 201
Rate - 1.10Q Pd'03-4.40 '02-4.40
1.10 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $4.44 p$100 — 300
Rate - 1.11Q Pd'03-4.44 '02-4.44
1.11 Oct 06 Nov 12 Nov 14 Dec 15
■ PFD $4.52 p$100 — 409
Rate - 1.13Q Pd'03-4.52 '02-4.52
1.13 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $5 p$100 — 508
Rate - 1.25Q Pd'03-5.00 '02-5.00
1.25 Oct 06 Nov 12 Nov 14 Dec 15
■ PFD $5.08 p$100 — 607
Rate - 1.27Q Pd'03-5.08 '02-5.08
1.27 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $6.08 p$100 — 706
Rate - 1.52Q Pd'03-6.08 '02-6.08
1.52 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $4.50 np — 789
Rate - 1.125Q Pd'03-4.50 '02-4.50
1.125 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $4.40 np — 797
Rate - 1.10Q Pd'03-4.40 '02-4.40
1.10 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $4.20 p$100 — 805
Rate - 1.05Q Pd'03-4.20 '02-4.20
1.05 Oct 06 Nov 12 Nov 14 Dec 15
■ DEPOSITARY SH REPSTG 1/2 PFD B ADJ p$50 — 821
Rate - 0.875Q Pd'03-3.50 '02-3.50
0.875 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD SER A ADJUSTABLE RATE p$100 — 839
Rate - Q-Amts Pd'03-7.00 '02-7.00
1.75 Oct 06 Nov 12 Nov 14 Dec 15
◇ PFD $7.56 p$100 — 847
Rate - 1.89Q Pd'03-7.56 '02-7.56
1.89 Oct 06 Nov 12 Nov 14 Dec 15

ENTERGY MISS INC
■ 1ST MTG BDS 6% SER p$25 — 29364N 875
Rate - 0.375Q Pd'03-1.5375 '02- None
†0.375 Oct 07 Oct 29 Oct 31 Nov 03
†Interest Payment

ENTERPRISE PRODS PARTNERS L P
■ COM UNIT np — 293792 107
Rate - 0.3725Q Pd'03-1.4425 '02- new-0.68: old-1.295 & Stk
0.3725 Oct 09 Oct 29 Oct 31 Nov 12

EOTT ENERGY LLC (NOW LINK ENERGY LLC)
◇ COMMON UNITS np — 29412N 100
SEE LINK ENERGY LLC [CUSIP 535763]

EPHRATA NATL BK PA
◇ COM PAR $1 np — 294209 200
Rate - 0.25Q Pd'03-0.96 '02-0.87
0.25 Oct 29 Nov 12 Nov 14 Dec 15

EQUITABLE RES CAP TR I
■ CAP SECS 7.35% p$25 — 294550 207
Rate - None Pd'03-0.9895828 '02-1.8375
*0.0408328 — — — Apr 23
Called Apr 23 at $25 a sh at Deutsche Bk Tr Co, New York, NY & this divd
*Interest Payment

EQUITABLE RES INC
■ COM np ✥ — 294549 100
Rate - 0.30Q Pd'03-0.97 '02-0.67
0.30 Oct 17 Nov 12 Nov 14 Dec 01

EQUITY INV FD
▲ UNIT 1ST EXCHANGE SER-AT&T SHS np — 294700 703
Rate - M-Amts Pd'03-2.366 '02-2.469
*0.222 Oct 08 Oct 10 Oct 15 Nov 01
*Interest Payment

EQUITY OFFICE PPTYS TR
■ PFD CONV SER B 5.25% p$50 — 294741 509
Rate - 0.65625Q Pd'03-2.625 '02-2.625
0.65625 Oct 15 Oct 30 Nov 03 Nov 17

EQUITY SECS TR I
■ EQUITY TR SECS EXCH CABLEVISIO p$36.05 — 29477R 103
Rate - 0.5858Q Pd'03-2.3432 '02-2.4864
0.5858 Oct 07 Oct 29 Nov 01 Nov 17

EQUITY SECS TR II
■ EQUITY TR SECS EXCH INTO p$22.50 — 29477Q 204
Rate - 0.3516Q Pd'03-1.4064 '02-1.2775
0.3516 Oct 07 Oct 29 Nov 01 Nov 17

ERESEARCHTECHNOLOGY INC
✦ COM np — 29481V 108
Rate - None Pd'03- Stk '02- Stk
3-for-2 Split Oct 22 Nov 28 Nov 05 Nov 26
Due bills after Nov 05 redeemable Dec 02

ESKOM
◇ *GLOBAL DEP RCPT REP MAT OF STK 168 np — 296463 300
Rate - None Pd'03-146.57018 Apx '02-115.06934
†79.25072 Apx — Oct 29 Oct 31 Dec 03
*Represents 10,000 Ord shs
†Free of South African tax

EUROPE 2001 HOLDRS TR
▲ DEPOSITARY RCPT np — 29875G 105
Rate - None Pd'03-0.91320287 Apx '02- None
0.0216 — Aug 21 Aug 25 Sep 30
US fds. before 25% tax. Net after tax and 0.75% Dutch commission $0.016038
0.003 — Oct 07 Oct 09 Oct 14
Net amt
0.0137949 — Oct 09 Oct 14 Oct 24
Net amt
0.02066121 Apx — Nov 05 Nov 07 Dec 03
US fds. before 25% tax. Net after tax $0.01549591 apx.
0.01732 — Nov 12 Nov 14 Dec 10
US fds. before 10% tax. Net after tax $0.010588
0.0180108 — Oct 29 Oct 31 Jan 08 04
US fds. Net after $0.015 fee $0.0030108

EVEREST RE CAP TR
■ GTD TR PFD SECS 7.85% P$25 — 299807 206
Rate - 0.490625Q Pd'03-1.9679513 '02- None
*0.490625 Oct 07 Oct 29 Nov 02 Nov 17
*Interest Payment

EVERGREEN INCOME ADVANTAGE FD
■ COM SHS np — 30023Y 105
Rate - M-Amts Pd'03-1.10 '02- None
0.1375 Oct 22 Nov 13 Nov 17 Dec 01

EVERGREEN MANAGED INCOME FD
▲ COM SHS np — 30024Y 104
Rate - 0.13084M Pd'03-0.52336 '02-; old-
0.13084 Oct 22 Nov 13 Nov 17 Dec 01

EVERGREEN MARINE CORP TAIWAN
◇ aGLOBAL DEPOSITARY RCPT 144A np — 300246 105
Rate - None Pd'03-0.0585248 & Stk '02-0.0875523 & Stk
f2% Stk — Aug 04 Aug 06 Oct 15
aRepresents 10 Ord shs
fHldrs required to pay 20% withholding tax.
◇ aGLOBAL DEPOSITARY RCPT REG S np — 204
Rate - None Pd'03-0.0585248 & Stk '02-0.0875523 & Stk
f2% Stk — Aug 04 Aug 06 Oct 15
aRepresents 10 Ord shs
fHldrs required to pay 20% withholding tax.

EVERTRUST FINL GROUP
✦ COM np — 300412 103
Rate - Q-Amts Pd'03-0.555 '02-0.455
0.185 Oct 28 Nov 12 Nov 14 Nov 28

EXCHANGE NATL BANCSHARES INC
✦ COM np — 301309 100
Rate - 0.18Q Pd'03- new-0.27: old-0.67 & Stk '02-0.88
0.09 Spl Oct 15 Nov 12 Nov 14 Dec 01

EXELON CORP
■ COM np (U) — 30161N 101
Rate - 0.50Q Pd'03-1.82 '02-1.76
0.50 Oct 28 Nov 12 Nov 15 Dec 10

EXMAILIT COM
◇ COM np — 302082 102
Rate - None Pd'03- Stk '02- None
*16-for-1 Split — Oct 17 Oct 16 Oct 16
Due bills after Oct 16 redeemable Oct 21
*Also, name changed to Cirond Corp [CUSIP 17275N 101]

EXTENDED STAY AMER INC
■ COM np ✥ — 30224P 101
Rate - 0.04 Pd'03-0.04 '02- None
Prev divd 2-for-1 Split Jul 19 '96
0.04 Init Oct 28 Nov 06 Nov 10 Nov 25

EXTENDICARE INC CDA
PFD SER 2 np TOR — 30224T 400
Rate - Q-Amts Pd'03-0.832 '02-0.7549
g0.2080 Oct 15 Oct 29 Oct 31 Nov 17

Divd $ Declared Ex-Date Stk Record CUSIP Payable

GS FINL CORP 362274
✦ COM np 102
Rate - 0.10Q Pd'03-0.40 '02-0.36
0.10 Oct 09 Oct 20 Oct 22 Nov 05

GTECH HLDGS CORP 400518
■ COM np ❖ 106
Rate - 0.17Q Pd'03-0.34 '02- None
0.17 Oct 06 Oct 10 Oct 15 Oct 31

GUANGZHOU INVT LTD 40065R
◇ *SPONSORED ADR np 108
Rate - None Pd'03-0.0206 Apx '02- None
†0.0206 Apx — Oct 23 Oct 27 Nov 20
*Represent 20 Ord shs.
†Not subject to Hong Kong withholding tax. Net after $0.004 fee $0.0166 apx.

GUARANTY FINL CORP 40108Q
◇ COM np 109
Rate - None Pd'03-10.12 '02- None
0.12 Oct 15 Oct 29 Nov 01 Nov 06

GUARANTY FINL CORP VA 401086
✦ COM np 103
Rate - 0.075Q Pd'03-0.30 '02- None
0.075 Oct 20 Oct 29 Oct 31 Nov 10

GUCCI GROUP N V 401566
■ SHS-N Y REGISTRY np 104
Rate - None Pd'03-16.3425 '02-0.50
b0.5583 — Jul 18 Jul 22 Aug 06
c15.7842 — Sep 26 Sep 30 Oct 07
bBefore 25% Netherlands tax to US res. Net after tax $0.4187
cFree of Netherland tax.

GUIDANT CORP 401698
■ COM np (I) 105
Rate - 0.08Q Pd'03-0.24 '02- None
0.08 Oct 21 Nov 26 Dec 01 Dec 15

GUJARAT AMBUJA CEMENTS LTD 402042
◇ aGLOBAL DEPOSITARY RCPT 144A np 105
Rate - None Pd'03-0.1513 '02-0.1233
h0.0877 — Aug 15 Aug 19 Oct 16
aRepresents 1 Ord sh.
hFree of Indian tax. Net after $0.01 fee $0.0777

GUJARAT NARMADA VY FERTILIZERS 402044
◇ *GLOBAL DEPOSITARY RCPT 144A np 101
Rate - None '03- None '02- None
b — — Jul 30 —
*Represents 5 Ord shs.
bPlease disregard prev published $0.273 apx divd to hldrs of record Jul 30, as this divd has been cancelled.

GULF PWR CAP TR I 402473
■ QUARTERLY INCOME PFD SECS 7.625% p$25 201
Rate - None Pd'03-0.0794265 '02-1.90625
*0.0794265 Dec 20 — — Jan 15
Called Jan 15 '03 at $25 a sh at JPMorgan Cahse Bank, New York, NY & this divd.
*Interest Payment

GULF PWR CAP TR II 402476
■ QUARTERLY INCOME PFD SECS % 7% np 204
Rate - None Pd'03-1.3951387 '02-1.75
*0.0826387 — — — Oct 17
Called Oct 17 at $25 a sh at JP Morgan Chase Bank, New York, NY & this divd.
*Interest Payment

GULF PWR CO 402479
◇ PFD 4.64% p$100 208
Rate - 1.16Q Pd'03-4.64 '02-4.64
1.16 — Dec 11 Dec 15 Jan 01 04
◇ PFD 5.16% p$100 307
Rate - 1.29Q Pd'03-5.16 '02-5.16
1.29 — Dec 11 Dec 15 Jan 01 04
◇ PFD 5.44% p$100 406
Rate - 1.36Q Pd'03-5.44 '02-5.44
1.36 — Dec 11 Dec 15 Jan 01 04
■ SR NT p$25 786
Rate - 0.359375Q '03- None '02- None
*†0.3553819 Init Oct 17 Nov 25 Nov 30 Dec 15
*Covers period from Sep 16 thru Dec 15.
†Interest Payment

GULFTERRA ENERGY PARTNERS LP 40274U
■ COM np 108
Rate - 0.71Q Pd'03-2.76 '02-2.60
0.71 Oct 21 Oct 29 Oct 31 Nov 14

H QUOTIENT INC 40426E
◇ COM np 101
Rate - 0.01Q Pd'03-0.01 '02- None
0.01 Sep 30 Oct 29 Oct 31 Jan 02 04

H&R REAL ESTATE INVT TR 403925
UNIT np TOR 100
Rate - M-Amts Pd'03-1.02 '02-1.199
g0.102 Oct 09 Oct 20 Oct 22 Oct 31

HABERSHAM BANCORP INC 404459
✦ COM np 109
Rate - 0.06Q Pd'03-0.24 '02- None
1.00 Spl Oct 13 Nov 26 Dec 01 Dec 15

HAGGAR CORP 405173
✦ COM p$0.10 105
Rate - 0.05Q Pd'03-0.20 '02-0.20
0.05 Oct 28 Oct 30 Nov 03 Nov 17

HALLIBURTON CO 406216
■ COM p$2.50 (I) 101
Rate - 0.125Q Pd'03-0.50 '02-0.50
0.125 Oct 22 Nov 28 Dec 02 Dec 23

HAMILTON CAP TR I 407046
◇ CAP SECS SER A 9.75 % np 200
Rate - 0.24375Q '03- None '02- None
Arrears Oct 1 '03 - $2.4375

HANCOCK JOHN PATRIOT GLOBAL DIVID FD 41013G
■ COM np 103
Rate - M-Amts Pd'03-0.891 '02-0.972
0.081 Sep 30 Oct 08 Oct 10 Oct 31
0.081 Oct 28 Nov 05 Nov 07 Nov 28

HANCOCK JOHN PATRIOT PFD DIVID FD 41013J
■ COM np 107
Rate - M-Amts Pd'03-0.792 '02-0.864
0.072 Oct 29 Nov 06 Nov 10 Nov 28

HANCOCK JOHN PATRIOT PREM DIVID FD I 41013Q
■ COM np 101
Rate - M-Amts Pd'03-0.54 '02-0.648
0.054 Oct 07 Oct 15 Oct 17 Oct 31

HANCOCK JOHN PATRIOT PREM DIVID FD II 41013T
■ COM SH BEN INT np 105
Rate - M-Amts Pd'03-0.715 '02-1.02
0.065 Oct 10 Oct 20 Oct 22 Nov 17

HANCOCK JOHN PATRIOT SELECT DIVID TR 41013U
■ COM np 102
Rate - M-Amts Pd'03-0.99 '02-1.08
0.09 Oct 30 Nov 06 Nov 10 Nov 26

HANCOCK JOHN PFD INCOME FD 41013W
■ SH BEN INT np 108
Rate - M-Amts Pd'03-1.98 '02-0.36
0.18 Oct 09 Oct 16 Oct 20 Nov 03

HANCOCK JOHN PFD INCOME FD II 41013X
■ COM np 106
Rate - M-Amts Pd'03-1.80 '02- None
0.18 Oct 10 Oct 16 Oct 20 Nov 03

HANCOCK JOHN PFD INCOME FD III 41021P
■ COM np 103
Rate - M-Amts Pd'03-0.54 '02- None
0.18 Oct 01 Oct 09 Oct 14 Nov 03

HANOVER FOODS CORP 41078W
◇ CDT-CL A p$25.00 100
Rate - None Pd'03-0.275 '02- None
0.275 Oct 17 Nov 06 Nov 10 Dec 01
Prev divd $0.275 & $0.165 Spl Aug 15 '98

HANSON PLC 411352
■ *SPONSORED ADR NEW np 404
Rate - None Pd'03-1.3906519 '02-1.1696174
Converted into Hldg Co Hanson Plc (CUSIP 411349 100). Effective Oct 15.
*Represents 5 Ord shs.

HARBOR FLA BANCSHARES INC 411901
✦ COM np 101
Rate - 0.145Q Pd'03-0.55 '02-0.45
0.145 Oct 15 Oct 22 Oct 24 Nov 20

HARBOUR FRONT HLDGS INC 411622
◇ COM np 103
Rate - None '03- None '02- None
* Stk — Oct 20 — —
*1-for-200 Rev Split. Effective opening of business Oct 20. Also, name changed to American Eagle Manufacturing Co (CUSIP 025905 107).

HARLEYSVILLE SVGS FINL CORP 412865
✦ COM p$1 107
Rate - 0.20Q Pd'03-0.70 '02-0.57
0.20 Oct 15 Nov 03 Nov 05 Nov 19

HARMAN INTL INDS INC NEW 413086
■ COM p$0.01 109
Rate - 0.025Q Pd'03-0.10 '02-0.10
0.025 — Nov 07 Nov 12 Nov 26
*2-for-1 Split Oct 01 — † †
*Hldrs vote Nov 12
†To be announced.

HARRINGTON WEST FINL GROUP INC 41383L
✦ COM np 104
Rate - 0.10Q Pd'03-0.26 '02- None
0.10 Oct 16 Oct 22 Oct 24 Nov 07

HARRIS CORP DEL 413875
■ COM p$1 ❖ 105
Rate - 0.10Q Pd'03-0.36 '02-0.28
0.10 Oct 24 Nov 19 Nov 21 Dec 05

HARTFORD FINL SVCS GROUP INC 416515
■ COM np (F) 104
Rate - 0.28Q Pd'03-1.08 '02-1.04
0.28 Oct 16 Nov 26 Dec 01 Jan 02 04
■ EQUITY UNIT 6.00% 6% p$50 203
Rate - 0.75Q Pd'03-3.00 '02-0.525
0.75 Oct 08 Oct 30 Nov 03 Nov 17
■ NORMAL UNIT p$50 500
Rate - 0.80694444Q Pd'03-1.6138888 '02- None
0.80694444 Oct 08 Oct 29 Nov 01 Nov 17

HARTFORD INCOME SHS FD INC 416537
■ COM (WAS FORTIS SEC INC) p$0.01 108
Rate - M-Amts Pd'03-0.53 '02-0.63
0.046 Oct 16 Oct 23 Oct 27 Nov 17

HARVEST ENERGY TR 41752X
TR UNIT p$0 (Cdn) TOR 101
Rate - M-Amts Pd'03-2.20 '02- None
g0.20 Oct 20 Oct 29 Oct 31 Nov 14

HATTERAS INCOME SECS INC 419025
■ COM p$1 101
Rate - M-Amts Pd'03-0.65 '02-0.855
0.065 Oct 03 Oct 08 Oct 13 Oct 31

HAVERTY FURNITURE COS INC 419596
■ COM p$1 101
Rate - 0.0625Q Pd'03-0.235 '02-0.22
0.0625 Oct 30 Nov 07 Nov 12 Dec 26
■ CL A p$1 200
Rate - 0.0575Q Pd'03-0.215 '02-0.205
0.0575 Oct 30 Nov 07 Nov 12 Nov 26

HAWAIIAN ELEC INC 419866
◇ PFD SER C 4.25% p$20 207
Rate - 0.2125Q Pd'03-0.85 '02-0.85
0.2125 — Oct 01 Oct 06 Oct 15
◇ PFD SER D 5% p$100 306
Rate - 0.25Q Pd'03-1.00 '02-1.00
0.25 — Oct 01 Oct 05 Oct 15
◇ PFD SER E 5% p$20 405
Rate - 0.25Q Pd'03-1.00 '02-1.00
0.25 — Oct 01 Oct 08 Oct 15
◇ PFD SER I 5% p$20 504
Rate - 0.25Q Pd'03-1.00 '02-1.00
0.25 — Oct 01 Oct 05 Oct 15
◇ CDT-PFD SER H 5.250% np 843
Rate - 0.2625Q Pd'03-1.05 '02-1.05
0.2625 — Oct 01 Oct 05 Oct 15
◇ CMT-PFD SER J 4.75% np 850
Rate - 0.2375Q Pd'03-0.95 '02-0.95
0.2375 — Oct 01 Oct 05 Oct 15
◇ CMT-PFD SER K 4.65% np 868
Rate - 0.2325Q Pd'03-0.93 '02-0.93
0.2325 — Oct 01 Oct 05 Oct 15

HAWAIIAN ELEC INDS INC 419870
■ COM p$3.33 ❖ 100
Rate - 0.62Q Pd'03-2.48 '02-2.48
0.62 Oct 28 Nov 06 Nov 10 Dec 10

HAWTHORNE FINL CORP 420542
✦ COM p$1 102
Rate - None Pd'03- Stk '02- None
*3-for-2 Split Sep 25 Oct 28 Oct 06 Oct 27
Due bills after Oct 06 redeemable Oct 30.
Prev divd $0.25 Feb 1 '93
*Fractions in cash

HBOS PLC 42205M
◇ *SPONSORED ADR np 106
Rate - None Pd'03-1.4748 '02-1.41781
d0.51531 — Aug 13 Aug 15 Oct 24
*Represents 3 Ord shs.
dFree of British tax.

HEALTH CARE PPTY INVS INC 421915
■ COM p$1 109
Rate - 0.83Q Pd'03-3.32 '02-3.28
0.83 Oct 23 Oct 31 Nov 04 Nov 20
■ DEPOSITARY SH REPSTG 1/100TH PFD SER C 8.60% np 604
Rate - None Pd'03-0.7286104 '02-2.15
0.1811104 — — — May 02
Called May 2 at $25 a sh at Wells Fargo Bk Minnesota N A & this divd.
◇ PFD SER E np 802
Rate - None Pd'03-0.53368 '02- None
0.53368 Init Oct 23 Dec 11 Dec 15 Dec 31

HEALTH CARE REIT INC 42217K
■ COM p$1 106
Rate - 0.585Q Pd'03-2.34 '02-2.34
0.585 Oct 22 Oct 30 Nov 03 Nov 20

Divd $ | Declared | Ex-Date | Stk Record | CUSIP Payable

JBI CAP TR I 46610Q
◇ GTD PFD SECS 9.25% p$25 206
Rate - None Pd'03-0.7836802 '02-1.734375
*0.2055552 — — Feb 03
Called Feb 3 & this divd.
*Interest Payment

JD WEATHERSPOON PLC 472146
◇ *SPONSORED ADR np 109
Rate - None Pd'03-0.2919 Apx '02-0.2711
d0.1932 Apx — Oct 29 Oct 31 Dec 08
*Represents 5 Ord shs
dFree of British tax. Net after $0.02 fee $0.1732 apx.

JEAN COUTU GROUP PJC INC 47215Q
CL A SUB VTG np TOR 104
Rate - 0.03Q Pd'03-0.12 '02- new-0.03; old-0.16 & Stk
g0.03 Oct 15 Nov 10 Nov 13 Nov 27

JEFFERIES GROUP INC NEW 472319
■ COM np 102
Rate - 0.08Q Pd'03- new-0.16; old-0.10 & Stk '02-0.20
0.08 Oct 14 Nov 13 Nov 17 Dec 15

JERSEY CENT PWR & LT CO 476556
■ PFD 4% np 204
Rate - 1.00Q Pd'03-4.00 '02-4.00
1.00 Oct 02 Oct 10 Oct 15 Nov 01

JETBLUE AWYS CORP 477143
✦ COM p$0.01 ❖ 101
Rate - None Pd'03- Stk '02- Stk
3-for-2 Split Oct 07 Nov 21 Nov 10 Nov 20
Due bills after Nov 10 redeemable Nov 25

JG SUMMIT HLDGS INC 466152
◇ *SPONSORED GLOBAL DEP RCPT 144A np 105
Rate - None Pd'03-0.054064 '02-0.0574712
b0.054054 — Sep 04 Sep 08 Oct 09
*Represents 100 Ord shs
bBefore 25% Philippine tax to US res. Net after tax & $0.005 fee $0.0355405

JIANGLING MTRS LTD 477372
◇ SPONSORED ADR REPSTG CL B SHS np 106
Rate - None Pd'03-1.2184223 '02- None
*1.2184223 — Sep 25 Sep 29 Oct 16
*Not subject to Chinese withholding tax. Net after $0.02 fee $1.1984223

JO-ANN STORES INC 47758P
■ CL A np 109
Rate - None '03- None '02- None
Reclassified into Com [CUSIP 47758P 307]. Effective Nov 4. Prev divd in CL B shs (as Fabri Ctrs Amer Inc) Aug 16 '95
Reclassified into com [CUSIP47758P 307]. Effective Nov 5.

JOHNSON & JOHNSON 478160
■ COM p$1 (I) 104
Rate - 0.24Q Pd'03-0.925 '02-0.795
0.24 Oct 16 Nov 14 Nov 18 Dec 09

JONES APPAREL GROUP INC 480074
■ COM p$0.01 (I) 103
Rate - 0.08Q Pd'03-0.16 '02- None
0.08 Oct 28 Nov 12 Nov 14 Nov 28

JUNIATA VALLEY NATL BK 482016
◇ COM np 102
Rate - 0.53S Pd'03-1.00 '02-0.88
0.53 Oct 21 Oct 29 Nov 01 Dec 01

JURAK CORP WORLD WIDE INC 482074
◇ COM np 101
Rate - None Pd'03- Stk '02- None
2-for-1 Split — Oct 23 Oct 14 Oct 22
Due bills after Oct 14 redeemable Oct 27

K WAH INTL HLDGS LTD 482774
◇ *SPONSORED ADR np 106
Rate - None Pd'03-0.0256 '02-0.0384
d0.0129 Apx — Oct 09 Oct 14 —
*Represents 10 Ord shs
dNot subject to Hong Kong withholding tax. Net after $0.002 fee $0.0109 apx.

KAISER ALUM & CHEM CORP 483008
◇ PREF CONV 4.125% p$100 306
Rate - None '03- None '02- None
Arrears Sep 1 '03 - $7.21875
◇ PREF CONV 4.75% SER 57 p$100 405
Rate - None '03- None '02- None
Arrears Sep 1 '03 - $8.3125
◇ PREF SER 59 CONV 4.75% p$100 504
Rate - None '03- None '02- None
Arrears Sep 1 '03 - $8.3125
◇ PREF SER 66 CONV 4.75% p$100 603
Rate - None '03- None '02- None
Arrears Sep 1 '03 - $8.3125

KANEB PIPE LINE PARTNERS L P 484169
■ SR PREF UNIT np 107
Rate - 0.84Q Pd'03-3.25 '02-3.12
*0.84 Oct 23 Oct 30 Nov 03 Nov 14
*Limited Partnership distribution

KANEB SVCS LLC 484173
■ COM np 109
Rate - 0.475Q Pd'03-1.7625 '02-1.60
0.475 Oct 23 Oct 30 Nov 03 Nov 14

KANKAKEE BANCORP INC (NOW CENTRUE FINL CORP) 484243
▲ COM p$0.01 100
SEE CENTRUE FINL CORP [CUSIP 15641R]

KANSAS CITY LIFE INS CO 484836
✦ COM p$2.50 101
Rate - 0.27Q Pd'03-1.08 '02-1.08
0.27 Oct 27 Nov 06 Nov 10 Nov 24

KAO CORP 485537
◇ *ADR np 203
Rate - None '03- None '02- None
†1.37445 Apx — Sep 25 Sep 29 Dec 16
*Represents 1 Com shs
†Before 10% Japanese tax to US res. Net after tax & $0.02 fee $1.217 apx.

KB HOME 48666K
■ COM p$1 (I) 109
Rate - 0.075Q Pd'03-0.30 '02-0.30
0.075 Oct 02 Nov 07 Nov 12 Nov 26

KBF POLLUTION MGMT INC 482396
◇ COM np 108
Rate - None '03- None '02- None
*1-for-20 Rev Split — Oct 21 — —
*Effective opening of business Oct 21. Also, name changed to Veridium Corp [CUSIP 92342S 102].

KBSH LEADERS TR 482421
UNIT np TOR 104
Rate - M-Amts Pd'03-1.67818 '02-1.5823
g0.14083 Oct 01 Oct 10 Oct 15 Oct 31

KCP INCOME FD 48667F
UNIT DIVIDED INT np TOR 109
Rate - M-Amts Pd'03-1.00826 '02-0.29682
g0.09166 Oct 20 Oct 29 Oct 31 Nov 26

KEG ROYALTIES INCOME FD 487522
UNIT np TOR 104
Rate - M-Amts Pd'03-0.90 '02-0.54
g0.09 Oct 13 Oct 17 Oct 21 Oct 31

KELLOGG CO 487836
■ COM p$0.25 (I) 108
Rate - 0.2525Q Pd'03-1.01 '02-1.01
0.2525 Oct 31 Nov 25 Nov 28 Dec 15

KENNAMETAL INC 489170
■ COM p$1.25 ❖ 100
Rate - 0.17Q Pd'03-0.68 '02-0.68
0.17 Oct 29 Nov 06 Nov 10 Nov 25

KENTUCKY FIRST BANCORP INC 491290
▲ COM np 102
Rate - 0.16Q Pd'03-0.64 '02-0.64
0.16 Oct 02 Oct 15 Oct 17 Oct 31

KENTUCKY PWR CO 491386
■ JR SUB DEB DEFERABLE SER A 8.72% np 108
Rate - None Pd'03-0.908 '02-2.18
*0.363 — — — May 30
Called May 30 at $25 a sh at Bank One Tr Co, N.A. New York, NY & this divd.
*Interest Payment

KENTUCKY UTILS CO 491674
PFD 4.75% np PHL 206
Rate - 1.1875Q Pd'03-4.75 '02-4.75
1.1875 Oct 16 Nov 12 Nov 14 Dec 01
◇ PFD 6.53% np 602
Rate - 1.6325Q Pd'03-6.53 '02-6.53
1.6325 Oct 16 Nov 12 Nov 14 Dec 01

KENTUCKY-AMERICAN WTR CO 49119A
◇ CDT-PFD SER B 5.75% np 201
Rate - 1.4375Q Pd'03-5.75 '02-5.75
1.4375 Oct 24 Dec 10 Dec 12 Jan 01 04
◇ CDT-PFD SER D 5% np 300
Rate - 1.25Q Pd'03-5.00 '02-5.00
1.25 Oct 24 Dec 10 Dec 12 Jan 01 04
◇ CMT-PFD SER C 5.50% np 409
Rate - 1.375Q Pd'03-5.50 '02-5.50
1.375 Oct 24 Dec 10 Dec 12 Jan 01 04

KERR GROUP INC 492376
■ PFD CL B SER D CONV $1.70 p$0.50 207
Rate - None '03- None '02- None
Arrears Sep 30 '03 - $12.75

KEYSPAN CORP 49337W
■ CORP MEDS 8.75% p$50 407
Rate - 1.0938Q Pd'03-4.3752 '02-2.3038
†1.0938 Oct 23 Nov 12 Nov 14 Nov 17
†Interest Payment

KEYSPAN FACS INCOME FD 49337Y
TR UNIT $10 (Cdn) TOR 106
Rate - M-Amts Pd'03-0.454 '02- None
g0.0908 Oct 22 Oct 29 Oct 31 Nov 17

KEYSTONE PPTY TR CORP 493596
■ COM p$0.001 100
Rate - 0.33Q Pd'03-1.31 '02-1.29
0.33 Oct 03 Oct 15 Oct 17 Oct 31
■ PFD SER D % np 308
Rate - 0.5703125Q Pd'03-1.596875 '02- None
0.5703125 Oct 03 Oct 15 Oct 17 Oct 31

KIDDE PLC 493793
◇ *SPONSORED ADR np 103
Rate - None Pd'03-0.4282 '02-0.4058
d0.1507 — Oct 01 Oct 03 Nov 03
*Represents 10 Ord shs
dFree of British tax. Net after $0.018 fee $0.1327

KIMBERLY CLARK DE MEXICO S A 494386
◇ *SPONSORED ADR REPSTG ORD PARTN np 204
Rate - None Pd'03-0.8258 Apx '02-0.87165
†0.21446 — Jun 27 Jul 01 Jul 10
†0.20071 — Sep 29 Oct 01 Oct 09
†0.20071 Apx — Dec 01 Dec 03 Dec 11
*Represents 5 Ord shs.
†Free of Mexican tax.

KIMCO RLTY CORP 49446R
■ COM np 109
Rate - 0.57Q Pd'03-2.16 '02-2.08
0.57 Oct 30 Dec 30 Jan 02 Jan 15 04
■ DEPOSITARY SH REPSTG 1/10 PFD SER A 7.75% p$1 307
Rate - None Pd'03-1.0979156 '02-1.9375
0.1291656 — — — Jun 09
Called Jun 9 at $25 a sh at Bank of New York, NY & this divd
■ DEPOSITARY SH REPSTG 1/10 PFD B 8.50% p$1.00 505
Rate - None Pd'03-1.3399269 '02-2.125
0.2774269 — — — Jun 02
Called Jun 2 at $25 a sh & this divd.
■ DEPOSITARY SH REPSTG 1/10 PFD C 8.375% np 604
Rate - None Pd'03-1.3909694 '02-2.0938
0.3140694 — — — Jun 09
Called Jun 9 at $25 a sh at Bank of New York, NY & this divd

KINAM GOLD INC 494482
◇ PFD CONV SER B $3.75 p$1 201
Rate - None '03- None '02- None
Arrears Aug 28 '03 - $12.1875

KINDER MORGAN ENERGY PARTNERS 494550
■ UNIT LTD PARTNERSHIP INT np 106
Rate - 0.66Q Pd'03-2.575 '02-2.36
*0.66 Oct 15 Oct 29 Oct 31 Nov 14
*Limited Partnership distribution

KINDER MORGAN INC KANS 49455P
■ COM p$5 (U) 101
Rate - 0.40Q Pd'03-1.10 '02-0.30
0.40 Oct 15 Oct 29 Oct 31 Nov 14

KINDER MORGAN MGMT LLC 49455U
■ SHS 0.01 100
Rate - None Pd'03- Stk '02- Stk
f Stk Oct 17 Oct 29 Oct 31 Nov 14
fPayable in Stk. Cash equivalent $0.66

KLABIN S A 49834M
◇ *SPONSORED ADR REPSTG PREF SHS np 100
Rate - None Pd'03-0.2606 '02-0.1385
a0.2605 — Sep 25 Sep 29 Oct 20
*Represents 10 Ord shs
aBefore 0.38% Brazilian tax to US res. Net after tax & $0.02 fee $0.2356

KNAPE & VOGT MFG CO 498782
✦ COM p$2 101
Rate - 0.165Q Pd'03-0.66 '02-0.66
0.165 Oct 21 Nov 19 Nov 21 Dec 05
◇ CL B p$2 200
Rate - 0.15Q Pd'03-0.60 '02-0.60
0.15 Oct 21 Nov 19 Nov 21 Dec 05

KNIGHT RIDDER INC 499040
■ COM np (I) 103
Rate - 0.32Q Pd'03-1.18 '02-1.02
0.32 Oct 21 Nov 03 Nov 05 Nov 17

KOSS CORP 500692
✦ COM $0.01 108
Rate - 0.13Q Pd'03-0.52 '02-0.49
0.13 Sep 30 Oct 01 Sep 30 Oct 15

Divd $ | Declared | Ex-Date | Stk Record | CUSIP Payable

NIKKO CORDIAL CORP 654107
■ COM pY50 TOK 101
Rate - None Pd'03-4.00 '02-5.00
a¥3.00 — Sep 25 Sep 30 Nov 26
aBefore 10% Japanese tax to US res.
✧ *ADR np 208
Rate - None Pd'03-0.35801 Apx '02-0.41348
c0.2747 Apx — Sep 25 Sep 29 Dec 15
*Represents 10 Com shs
cBefore 10% Japanese tax to US res. Net after tax 7 $0.01 fee $0.23723 apx.

NL INDS INC 629156
■ COM NEW p$0.125 407
Rate - 0.20Q Pd'03-0.80 '02-3.30
0.20 Oct 21 Dec 10 Dec 12 Dec 29

NOBLE ENERGY INC 655044
■ COM p$3.33 1/3 ✧ 105
Rate - 0.05Q Pd'03-0.17 '02-0.16
0.05 Oct 28 Nov 06 Nov 10 Nov 24

NOLAND CO 655286
✦ COM p$10 102
Rate - 0.08Q Pd'03-0.32 '02-0.32
0.08 Oct 01 Oct 10 Oct 15 Oct 30

NORANDA INC 655422
■ COM np 103
Rate - 0.12Q Pd'03-0.64 '02-0.80
g0.12 Oct 23 Nov 25 Nov 28 Dec 15
PFD SER F CONV np TOR 806
Rate - M-Amts Pd'03-1.07543 '02-1.02088
g0.09375 Jul 25 Oct 29 Oct 31 Nov 12
g Amt later Oct 23 Nov 26 Nov 28 Dec 12
g Amt later Oct 23 Dec 29 Dec 31 Jan 12 04
PFD SER H np TOR 871
Rate - Q-Amts Pd'03-1.24583 '02- None
g0.40625 Oct 23 Nov 12 Nov 15 Dec 31
PFD SER G 6.5% np TOR 889
Rate - Q-Amts Pd'03-1.525 '02-1.525
g0.38125 Oct 28 Jan 13 Jan 15 Feb 01 04

NORANDA INCOME FD 655432
PRIORITY UNIT CL A np TOR 102
Rate - M-Amts Pd'03-0.93166 '02-0.57793
g0.085 Oct 21 Oct 29 Oct 31 Nov 25

NORCAL CMNTY BANCORP 655464
✧ COM np 103
Rate - None Pd'03- Stk '02- None
3-for-2 Split Oct 24 Dec 02 Nov 05 Dec 01
Due bills after Nov 05 redeemable Dec 04

NORFOLK SOUTHN CORP 655844
■ COM p$0.33 1/3 (T) 108
Rate - 0.08Q Pd'03-0.30 '02-0.26
0.08 Oct 21 Nov 05 Nov 07 Dec 10

NORFOLK SOUTHN RY CO VA 655855
■ PFD SER A $2.60 np 203
Rate - 0.65Q Pd'03-2.60 '02-2.60
0.65 Oct 09 Nov 05 Nov 07 Dec 15

NORTEL NETWORKS LTD 656569
PFD CL A SER 5 VAR RATE np TOR 308
Rate - M-Amts Pd'03-1.07776 '02-0.88942
g0.09375 Sep 25 Oct 29 Oct 31 Nov 12
g Amt later Oct 23 Nov 25 Nov 28 Dec 12
PFD CL A SER 7 VAR RATE np TOR 407
Rate - 0.09375Q Pd'03-1.02089 '02-1.225
g0.09375 Sep 25 Oct 29 Oct 31 Nov 12
g Amt later Oct 23 Nov 25 Nov 28 Dec 12

NORTH BANCSHARES INC 657467
✦ COM p$0.01 106
Rate - 0.08Q Pd'03-0.36 '02-0.44
0.08 — Oct 29 Oct 31 Nov 14

NORTH COAST ENERGY INC 658649
✧ PFD CONV SER B p$0.01 405
Rate - None '03- None '02-0.25
Arrears Sep 30 '03 - $1.75

NORTH COAST LIFE INS CO 658654
✧ PFD CONV SER A 10% p$2 207
Rate - None '03- None '02-1.00
Arrears Oct 30 '03 $2.00

NORTH EUROPEAN OIL RTY TR 659310
■ CTF BEN INT np 106
Rate - Q-Amts Pd'03-1.95 '02-1.89
*†0.45 Oct 30 Nov 12 Nov 14 Nov 26
*Withholding of US income tax from nonresident aliens is not required.
†Distribution to hldrs from royalties rec'd from gas & oil sales.

NORTH PITTSBURGH SYS INC 661562
✦ COM p$0.3125 108
Rate - 0.17Q Pd'03-0.68 '02-0.68
0.17 Sep 26 Sep 30 Oct 01 Oct 15
0.17 Oct 28 Dec 30 Jan 02 Jan 15 04

NORTHEAST BANCORP 663904
▲ COM p$1.00 100
Rate - 0.09Q Pd'03-0.33 '02-0.285
0.09 Oct 23 Oct 29 Oct 31 Nov 22

NORTHEAST IND BANCORP INC 664196
✦ COM p$0.01 102
Rate - 0.14Q Pd'03-0.53 '02-0.49
0.14 Oct 29 Nov 13 Nov 17 Nov 28

NORTHEAST UTILS 664397
■ COM p$5 ✧ 106
Rate - 0.15Q Pd'03-0.575 '02-0.525
0.15 Oct 16 Nov 26 Dec 01 Dec 31

NORTHERN BORDER PARTNERS L P 664785
■ UNIT LTD PARTNERSHIP INT np 102
Rate - 0.80Q Pd'03-3.20 '02-3.20
*0.80 Oct 21 Oct 29 Oct 31 Nov 14
*Limited Partnership distribution

NORTHERN EMPIRE BANCSHARES 665112
✧ COM np 108
Rate - None Pd'03- Stk '02- Stk
2-for-1 Split Oct 22 Dec 16 Dec 01 Dec 15
Due bills after Dec 01 redeemable Dec 18

NORTHERN PPTY REAL ESTATE INVT 665624
TR UNIT np TOR 102
Rate - M-Amts Pd'03-1.0538 '02-0.5811
g0.0858 Oct 15 Oct 29 Oct 31 Nov 15
g0.0987 Oct 30 Dec 29 Dec 31 Jan 15 04

NORTHERN STS FINL CORP 665751
✦ COM p$2 103
Rate - 0.54S Pd'03-1.08 '02-1.06
0.54 Oct 22 Nov 12 Nov 14 Dec 01

NORTHFIELD PRECISION INSTR 666280
✧ COM p$0.10 102
Rate - S-Amts Pd'03-0.50 '02-0.50
0.25 Oct 21 Nov 14 Nov 18 Dec 16

NORTHLAND PWR INCOME FD 666910
TR UNIT np TOR 104
Rate - M-Amts Pd'03-0.90 '02-1.015
g0.08 Oct 22 Oct 29 Oct 31 Nov 14

NORTHRIM BANCORP INC 666762
✦ COM p$1 109
Rate - 0.095Q Pd'03-0.335 '02-0.28
0.095 Oct 03 Oct 15 Oct 17 Oct 31

NORTHROP GRUMMAN CORP 666807
■ EQUITY SECS UNITS p$100 409
Rate - 1.8125Q Pd'03-7.25 '02-7.1493
†1.8125 Oct 23 Nov 12 Nov 14 Nov 17
†Interest Payment

NORTHUMBERLAND BANCORP 667056
✧ COM np 105
Rate - 0.20Q Pd'03-0.56 & Stk '02-0.66
2-for-1 Split Oct 02 Oct 17 Oct 09 Oct 16
Due bills after Oct 09 redeemable Oct 21

NORTHWAY FINL INC 667270
✦ COM np 102
Rate - 0.17Q Pd'03-0.68 '02-0.68
0.17 Oct 28 Nov 05 Nov 07 Nov 12

NORTHWEST AIRLS INC 667281
■ SR QUARTERLY INT BD 9.50% p$25 208
Rate - 0.59375Q Pd'03-2.375 '02-2.375
†0.59375 Oct 08 Oct 29 Oct 31 Nov 17
†Interest Payment

NORTHWEST BANCORP INC PA 667328
✦ COM p$0.10 108
Rate - 0.10Q Pd'03-0.38 '02-0.28
0.10 Oct 21 Oct 29 Oct 31 Nov 14

NORTHWEST NAT GAS CO 667655
■ COM np 104
Rate - 0.325Q Pd'03-1.27 '02-1.26
0.325 Oct 02 Oct 29 Oct 31 Nov 14

NOVA SCOTIA PWR INC 669816
PFD SER C np TOR 605
Rate - 0.30625Q Pd'03-1.225 '02-1.225
g0.30625 Oct 03 Dec 16 Dec 18 Jan 01 04
1ST PFD SER D % np TOR 803
Rate - 0.36875Q Pd'03-1.475 '02-1.475
g0.36875 Oct 03 Dec 29 Jan 01 Jan 15 04

NOVAR PLC 66987Q
✧ ‡ADR np 100
Rate - None Pd'03-0.17 '02-0.1561
d0.049 — Sep 10 Sep 12 Nov 03
‡Represents 1 Ord sh
dFree of British tax. Net $0.005 fee $0.044

NOVASTAR FINL INC 669947
■ COM np 400
Rate - Q-Amts Pd'03-9.18 & Stk '02-3.17
2.50 Oct 29 Nov 03 Nov 05 Nov 19
2-for-1 Split Oct 29 Dec 02 Nov 17 Dec 01
Due bills after Nov 17 redeemable Dec 04

NOVICOURT INC 669908
COM np TOR 102
Rate - 0.10S Pd'03-0.20 '02-0.20
g0.10 Oct 30 Nov 12 Nov 15 Nov 29

NOVITRON INTL INC (NOW CLINICAL DATA INC NEW) 670088
✦ COM NEW np 202
SEE CLINICAL DATA INC NEW [CUSIP 18725U]

NPB CAP TR 629359
✦ TR PFD SECS 9% np 209
Rate - None '03- None '02-1.6875
*0.1875 — — — Oct 31 02
Called Oct 31 & this divd.
*Interest Payment

NSD BANCORP INC 62938D
✦ COM p$1 109
Rate - 0.22Q Pd'03-0.88 & Stk '02-0.81 & Stk
0.22 Oct 30 Dec 03 Dec 05 Dec 19

NUVEEN ARIZ DIVID ADVANTAGE 67069L
▲ COM SH BEN INT P$0.01 100
Rate - M-Amts Pd'03-0.75 '02-0.8896
0.0735 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN ARIZ DIVID ADVANTAGE 67071P
▲ COM np 107
Rate - M-Amts Pd'03-0.72 '02-0.5882
0.072 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN ARIZ DIVID ADVANTAGE 67072E
▲ COM np 101
Rate - M-Amts Pd'03-0.67 '02-0.134
0.067 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN ARIZ PREM INCOME MUN FD 67061W
■ COM p$0.01 104
Rate - M-Amts Pd'03-0.765 '02-0.904
0.0765 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF DIVID ADVANTAGE 3 67070Y
▲ COM FD 3 np 109
Rate - M-Amts Pd'03-0.72 '02-0.864
0.072 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF DIVID ADVANTAGE MUN FD 67066Y
■ COM np 105
Rate - M-Amts Pd'03-0.796 '02-0.8825
0.081 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF DIVID ADVANTAGE 67069X
▲ COM np 104
Rate - M-Amts Pd'03-0.747 '02-0.9071
0.076 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF INVT QUALITY MUN FD 67062A
■ COM FD p$0.01 101
Rate - M-Amts Pd'03-0.789 '02-0.9366
0.0795 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF MUN MKT OPPTY FD 67062U
■ COM p$0.01 107
Rate - M-Amts Pd'03-0.763 '02-0.9109
0.078 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF MUN VALUE FD INC 67062C
■ COM p$0.01 107
Rate - M-Amts Pd'03-0.415 '02-0.5282
0.04 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF PERFORMANCE PLUS MUN FD 67062Q
■ COM p$0.01 106
Rate - M-Amts Pd'03-0.769 '02-0.9021
0.0775 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF PREM INCOME MUN 6706L0
▲ COM p$0.01 102
Rate - M-Amts Pd'03-0.727 '02-0.846
0.073 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF QUALITY INCOME MUN FD 670985
■ COM P$0.01 100
Rate - M-Amts Pd'03-0.83 '02-1.0982
0.083 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF SELECT QUALITY 670975
■ COM p$0.01 101
Rate - M-Amts Pd'03-0.794 '02-0.9318
0.0805 Oct 01 Oct 10 Oct 15 Nov 03

NUVEEN CALIF SELECT TAX FREE INC 67063R
■ SH BEN INT np 103
Rate - M-Amts Pd'03-0.57 '02-0.6688
0.056 Oct 01 Oct 10 Oct 15 Nov 03

Entrp Prod Prtnr Common Stock (EPD)

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Monthly prices from 20 November 2002 to 20 November 2003

Currency: As reported Data: Unadjusted Exchange: New York Stock Exchange

Date	Close	Open	High	Low	Volume
30 November 2002	**17.76**	18.62	18.62	16.41	1,728,700
31 December 2002	**19.40**	17.85	19.77	17.05	2,561,500
31 January 2003	**19.00**	19.64	19.65	17.96	12,065,000
28 February 2003	**20.19**	19.05	20.19	18.61	4,650,500
31 March 2003	**20.85**	20.10	21.00	19.81	4,198,500
30 April 2003	**22.64**	20.75	23.10	20.62	3,625,100
31 May 2003	**22.35**	22.54	24.65	21.40	8,057,900
30 June 2003	**22.53**	22.37	23.32	22.01	6,919,500
31 July 2003	**21.90**	22.50	24.10	20.31	6,289,600
31 August 2003	**22.14**	21.80	22.44	20.76	3,573,900
30 September 2003	**22.60**	22.15	22.86	21.89	3,109,300
31 October 2003	**21.63**	22.50	22.69	21.00	4,152,100

Source: Reuters Investor

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Gulfterra Energy Common Stock (GTM)

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Monthly prices from 20 November 2002 to 20 November 2003

Currency: As reported Data: Unadjusted Exchange: New York Stock Exchange

Date	Close	Open	High	Low	Volume
30 November 2002	**29.80**	29.70	31.25	26.00	2,920,400
31 December 2002	**27.84**	30.05	30.05	27.20	2,240,400
31 January 2003	**30.99**	28.20	32.56	28.05	1,874,800
28 February 2003	**31.36**	31.20	32.36	27.85	2,809,600
31 March 2003	**31.03**	31.25	31.88	30.03	1,532,000
30 April 2003	**34.34**	31.00	34.75	30.96	4,748,200
31 May 2003	**36.62**	34.34	37.44	33.90	3,062,500
30 June 2003	**37.54**	36.60	38.00	36.07	3,717,400
31 July 2003	**38.52**	37.64	39.21	37.04	2,682,500
31 August 2003	**39.57**	38.51	39.88	37.40	1,930,400
30 September 2003	**40.10**	39.57	40.47	39.00	1,316,300
31 October 2003	**39.01**	40.00	42.12	38.40	5,088,900

Source: Reuters Investor

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Top of page

Kinder Morgan Common Stock (KMP)

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Monthly prices from 20 November 2002 to 20 November 2003

Currency: As reported Data: Unadjusted Exchange: New York Stock Exchange

Date	Close	Open	High	Low	Volume
30 November 2002	**35.12**	32.65	35.18	31.72	4,104,200
31 December 2002	**35.00**	35.50	35.65	33.75	5,191,000
31 January 2003	**35.95**	35.00	37.10	35.00	5,479,700
28 February 2003	**36.35**	36.10	36.60	33.51	3,994,200
31 March 2003	**37.00**	36.55	37.23	35.70	3,743,100
30 April 2003	**39.11**	37.25	40.28	37.10	3,861,300
31 May 2003	**39.33**	39.05	39.99	35.00	9,212,900
30 June 2003	**39.52**	39.48	40.20	38.50	5,958,000
31 July 2003	**39.83**	39.53	41.13	39.25	3,871,400
31 August 2003	**40.50**	40.03	40.69	38.65	3,029,700
30 September 2003	**42.80**	40.50	43.06	40.20	3,842,200
31 October 2003	**42.84**	43.00	44.63	42.69	3,334,600

Source: Reuters Investor

Kinder Morgan Common Stock (KMI)

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Monthly prices from 20 November 2002 to 20 November 2003

Currency: As reported Data: Unadjusted Exchange: New York Stock Exchange

Date	Close	Open	High	Low	Volume
30 November 2002	**41.05**	36.50	42.25	36.40	8,547,300
31 December 2002	**42.27**	41.30	42.98	40.36	7,975,300
31 January 2003	**45.11**	42.25	46.05	42.25	11,581,200
28 February 2003	**45.53**	45.10	46.85	44.54	9,478,000
31 March 2003	**45.00**	45.53	46.07	42.41	10,898,700
30 April 2003	**47.02**	45.00	48.07	44.00	10,650,100
31 May 2003	**51.05**	47.01	51.05	45.89	10,588,900
30 June 2003	**54.65**	51.60	56.91	51.40	12,249,300
31 July 2003	**53.50**	54.90	54.97	52.57	10,694,600
31 August 2003	**53.25**	53.60	54.19	52.83	7,265,600
30 September 2003	**54.01**	53.20	54.67	51.46	10,742,500
31 October 2003	**53.55**	54.35	58.50	52.65	16,652,500

Source: Reuters Investor

North Border Common Stock (NBP)

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Monthly prices from 20 November 2002 to 20 November 2003

Currency: As reported Data: Unadjusted Exchange: New York Stock Exchange

Date	Close	Open	High	Low	Volume
30 November 2002	**36.20**	35.30	36.69	33.50	1,145,500
31 December 2002	**37.87**	36.33	37.87	35.81	974,500
31 January 2003	**37.95**	37.75	39.00	37.10	1,444,500
28 February 2003	**37.90**	38.02	38.20	36.58	1,159,500
31 March 2003	**38.23**	37.90	38.50	36.63	1,069,800
30 April 2003	**39.98**	38.15	40.84	38.10	1,202,900
31 May 2003	**40.60**	39.98	41.99	38.78	2,356,800
30 June 2003	**41.75**	40.65	42.33	40.55	2,018,100
31 July 2003	**42.36**	41.90	44.07	41.55	1,786,700
31 August 2003	**43.84**	42.42	43.98	40.50	1,366,700
30 September 2003	**43.41**	43.85	44.00	41.88	1,050,300
31 October 2003	**39.85**	43.45	43.70	39.50	3,209,600

Source: Reuters Investor

SECTOR/INDUSTRY/COMPANY	PRICE	ACTUAL FISCAL YEAR	ACTUAL EPS	ESTIMATES-FISCAL YEAR ONE MEAN	FY1 PERCENT CHANGE ACTUAL	FY1 PERCENT CHANGE RELATIVE	FY1 6 MO.	FY1 REVISIONS %UP	FY1 REVISIONS %DOWN	FY1 COEFF. OF VAR.	ESTIMATES-FISCAL YEAR TWO MEAN	FY2 PERCENT CHANGE ACTUAL	FY2 PERCENT CHANGE RELATIVE	FY2 6 MO.	FY2 REVISIONS %UP	FY2 REVISIONS %DOWN	FY2 COEFF. OF VAR.	ESTIMATED 5 YR. GROWTH RATE MEDIAN	ESTIMATED 5 YR. GROWTH RATE S.D.
ENERGY			1.48	2.28	54.7	1.57	9.5	16	15	8.5	2.09	40.5	1.24	2.1	16	10	14.6	9	5
OIL			1.57	2.41	53.2	1.55	10.4	16	16	8.4	2.18	38.2	1.22	3.0	17	11	14.3	9	5
INTEGRATED INTL OILS			2.04	2.92	42.6	1.44	14.7	38	12	9.1	2.44	19.6	1.06	4.2	28	16	11.3	7	2
CHEVRON TEXACO	72-2	12/02	4.21D	6.33	50.3	1.52	17.2	46		8.5	4.87	15.8	1.02	2.2	36	5	13.2	7	3
EXXON MOBIL CORP	36-7	12/02	1.70D	2.37	39.6	1.41	13.8	40		9.4	2.06	21.0	1.07	5.1	30	4	10.5	8	2
QUICKSILVER RES	24-5	12/02	0.70D	0.92	31.1	1.33	-41.5	11	78	8.7	1.31	87.4	1.66	-44.4	8	58	33.5	15	3
INTREG DOMESTIC OILS			2.45	4.78	95.2	1.98	17.4	41	8	6.9	3.82	56.0	1.38	0.9	21	8	20.0	7	5
AMERADA HESS	48-2	12/02	6.18D	5.27	-14.7	0.86	1.7	35		7.7	4.05	-34.4	0.58	-8.7	24		35.0	6	2
CALLON PETE	7-0	12/02	-0.67D	-0.17	N+	NM	-VL	13	75	47.7	0.14	-+	NM	-71.1	14	57	387.0	33	11
CONOCOPHILLIPS	55-7	12/02	3.11D	6.05	94.4	1.97	20.9	59	5	6.7	4.75	52.8	1.35	1.0	25	10	18.3	8	6
GOODRICH PETE	4-7	12/02	-0.03D	0.19	-+	NM	58.3	67		19.0	0.21	-+	NM	N/A	67		33.0		
MARATHON OIL CP	28-1	12/02	1.81D	3.29	81.9	1.84	15.4	43		6.1	2.49	37.3	1.21	10.1	27	5	18.5	7	3
SUNOCO INC	39-2	12/02	-0.31D	4.01	-+	NM	10.9	33	6	6.6	4.16	-+	NM	-3.9	6	6	18.0	7	5
TESORO PETE	8-8	12/02	-1.93D	1.27	-+	NM	15.6	33		20.6	1.57	-+	NM	-7.5	9		28.8	11	6
OIL REFINERS			0.75	1.50	93.2	1.96	-11.6	6	2	8.0	1.72	122.6	1.97	-8.3		4	12.0	7	2
BUCKEYE PRTNR LP	40-0	12/02	2.65D	2.60	-1.9	0.99	-2.8			1.1	2.71	2.1	0.90	-0.7			2.3	5	1
ENTERPRISE PART	22-2	12/02	0.48D	0.85	76.3	1.79	-26.6			7.2	1.18	145.8	2.17	-9.1			10.2	10	1
HOLLY CP	25-0	12/02	N/AD	2.30	N/A		N/A				2.50	N/A		N/A					
PREMCOR INC	22-6	12/02	-0.22D	2.46	-+	NM	-7.2	20		16.4	2.52	-+	NM	-17.8		7	26.7	5	4
SUNOCO LOGIS	31-2	12/02	2.06D	2.50	21.4	1.23	2.2			8.7	2.64	28.0	1.13	1.4			11.4	4	1
TEPPCO PARTNERS	35-2	12/02	1.79D	1.59	-11.1	0.90	4.2		11	3.1	1.69	-5.3	0.84	4.3		11	3.7	8	1
WORLD FUEL SVCS	27-5	12/02	N/AD	1.93	N/A		4.3				2.20	N/A		4.8					
CRUDE OIL & GAS PRODTN			1.20	2.44	103.8	2.06	11.4	20	24	7.8	2.03	69.3	1.50	12.0	26	13	19.9	11	9
ANADARKO PETE CO	41-4	12/02	3.21D	5.00	55.7	1.58	7.5	39	21	5.5	4.09	27.5	1.13	5.4	29	14	17.9	15	11
BERRY PETROLEUM	18-5	12/02	1.37D	1.69	23.0	1.25	-6.6		50	30.6	1.17	-14.6	0.75	N/A		100			
BURLINGTON RES	45-1	12/02	2.03D	5.13	152.6	2.56	22.0	29	21	7.3	3.53	73.8	1.54	16.2	33	11	23.2	4	6
CABOT OIL & GAS	25-7	12/02	0.65D	2.43	273.3	3.78	14.6	33	22	4.4	2.22	241.9	3.02	71.2	50		8.3	4	2
CARRIZO OIL INC	6-7	12/02	0.26D	0.53	103.8	2.06	41.3			11.5	0.37	42.3	1.26	N/A			26.1	10	
CHESAPEAKE ENERG	10-1	12/02	0.55D	1.13	105.1	2.08	39.5	12	24	11.4	0.88	60.0	1.41	46.3	13	13	22.3	17	
CIMAREX ENERGY	20-5	12/02	1.31D	2.18	66.3	1.68	-1.0	17	33	5.1	1.63	24.3	1.10	-10.2		17	14.6	8	4
CLAYTON WILLIAMS	19-7	12/02	-0.58D	3.01	-+	NM	106.2				1.09	-+	NM	373.9					
DELTA PETROLEUM	5-0	6/02	-0.49D	0.12	-+	NM	9.1				0.24	-+	NM	41.2					
DENBURY RESOURCE	12-2	12/02	0.86D	1.17	35.8	1.37	-2.8	13	25	6.9	1.11	28.7	1.14	3.9	11	22	25.4	12	
DEVON ENERGY COR	47-8	12/02	3.41D	6.66	95.2	1.98	13.9	18	26	7.2	4.73	38.6	1.22	15.7	30	21	20.3	5	8
ENCORE ACQUISITI	19-7	12/02	1.26D	1.92	52.1	1.54	25.9	83		4.2	1.50	18.8	1.05	40.8	67		5.0	10	
ENSCO INTL	26-5	12/02	0.72D	0.75	4.8	1.06	-21.0	11	11	4.2	1.21	67.4	1.48	-17.0	19	7	12.2	15	7
EOG RESOURCES	40-7	12/02	0.79D	3.65	362.1	4.68	22.0	32	26	5.5	2.47	212.8	2.76	17.9	48	17	29.3	8	13
EQUITY OIL CO	3-5	12/02	0.08D	0.16	100.0	2.03	-38.5		50	35.4	0.13	56.3	1.38	N/A		50	84.9		
FOREST OIL CP	22-4	12/02	0.51D	2.28	347.2	4.53	16.3	12	35	9.7	1.76	245.3	3.05	38.0	25	13	31.5	9	7
FRONTIER OIL CO	15-0	12/02	0.69D	0.84	21.2	1.23	-55.1	13	63	58.8	1.89	174.3	2.42	-7.0		38	20.4		

SECTOR/INDUSTRY/COMPANY	PRICE	ACTUAL FISCAL YEAR	ACTUAL EPS	ESTIMATES-FISCAL YEAR 1 MEAN	PERCENT CHANGE ACTUAL	PERCENT CHANGE RELATIVE	6 MO.	REVISIONS %UP	%DOWN	COEFF. OF VAR.	ESTIMATES-FISCAL YEAR TWO MEAN	PERCENT CHANGE ACTUAL	PERCENT CHANGE RELATIVE	6 MO.	REVISIONS %UP	%DOWN	COEFF. OF VAR.	ESTIMATED L GROWTH RATE MEDIAN	S.D.
WILLBROS GROUP	10-0	12/02	1.59D	0.49	-69.3	0.31	-49.0			9.9	1.13	-28.8	0.63	-15.1			23.6	15	3
OFFSHORE DRILLERS			0.88	0.46	-48.2	0.52	-49.9	3	12	12.6	1.07	21.2	1.07	-29.0	3	12	24.9	18	9
ATWOOD OCEANICS	23-8	9/02	1.87D	-0.30	-VL	NM	-VL		14	6.9	-0.22	-VL	NM	-VL		43	247.1	48	
DIAMOND OFFSHORE	18-4	12/02	0.47D	-0.32	-VL	NM	-VL	10	14	21.0	0.45	-4.2	0.85	-42.5		14	35.4	16	9
NABORS INDS LTD	36-0	12/02	0.72D	1.25	74.1	1.76	6.1		4	2.9	2.13	196.5	2.62	-2.3		4	13.4	18	9
NEWPARK RES INC	4-4	12/02	0.01D	0.12	VL	12.32	-49.3			21.1	0.33	VL	28.73	-37.5			41.1	20	2
OCEANEERING INTL	23-1	12/02	1.69D	1.37	-19.0	0.82	-6.6		25	2.0	1.67	-1.4	0.87	-2.9		13	1.9	15	3
OFFSHORE LOGSTCS	19-4	3/03	1.77D	1.62	-8.5	0.93	-3.6			1.3	1.92	8.2	0.96	N/A	20		4.4	17	12
PETROLEUM HELICO	29-2	12/02	1.70D	1.60	-5.9	0.95	-49.2				3.00	76.5	1.56	-25.0					
PIONEER DRILLING	4-2	3/03	-0.31D	-0.05	N+	NM	-VL			141.4	0.33	-+	NM	N/A			51.4		
TIDEWATER INC	27-5	3/03	1.57D	1.40	-10.6	0.91	-38.5		14	11.2	1.97	25.3	1.11	-33.1		14	18.1	15	16
TRANSOCEAN INC	19-2	12/02	1.14D	0.24	-79.2	0.21	-74.6	7	19	25.1	0.86	-24.7	0.67	-41.5	7	14	40.5	15	7
ROYALTIES & LTD. PART.			2.65	4.22	59.2	1.61	9.9	12	8	5.3	3.89	38.4	1.22	10.2	14	5	12.0	6	3
APACHE CP	66-4	12/02	3.60D	7.16	98.9	2.01	12.3	22	14	5.9	5.60	55.6	1.38	13.3	26	6	15.4	6	4
CORNERSTONE PROP	0-0	6/01	-0.29D	-1.06	N-	NM	0.0												
FERRELLGAS PRTNR	22-5	7/02	1.34D	1.63	21.6	1.23	3.8			4.3	1.54	14.8	1.01	0.2			8.9	1	2
HERITAGE PROPANE	32-6	8/02	0.25D	1.72	588.6	6.97	27.3			5.1	1.66	564.6	5.87	16.2			7.3	5	1
HUGOTON RLTY	18-7	12/01	1.98D	0.87	-56.3	0.44	0.0			0.8	2.01	1.3	0.90	25.7			3.2	10	
KANEB PIPE LINE	45-2	12/01	3.32D	3.05	-8.0	0.93	-1.1			2.6	3.14	-5.5	0.84	-4.0		17	2.4	5	2
NORTHN BORDER PA	43-7	12/02	2.61D	2.54	-2.6	0.99	-2.7			2.1	2.67	2.4	0.91	-4.3			2.1	7	2
COAL			0.62	1.01	55.6	1.58	-9.1	4	11	9.4	1.69	169.5	2.38	-1.5	7	5	14.9	8	6
ALLIANCE RES PRT	28-2	12/02	2.24D	2.17	-3.0	0.98	-1.2	33		3.0	2.30	2.7	0.91	-8.0	33		7.5	3	4
ARCH COAL INC	22-2	12/02	-0.14D	-0.03	N+	NM	-VL			329.8	1.19	-+	NM	1.0			24.9	10	11
CONSOL ENERGY	18-4	12/02	0.15D	0.66	337.9	4.43	-32.2		23	12.2	1.55	934.9	9.15	-6.0		23	12.0	12	9
NATURAL RESOURCE	36-1	12/02	N/AD	1.73	N/A		25.9			2.9	1.77	N/A		25.5			7.5	5	
PEABODY ENERGY	31-0	12/02	1.41D	1.73	22.8	1.24	26.8	8		5.1	2.10	49.0	1.32	15.4	8		9.5	7	5
PENN VA CORP	43-4	12/02	1.34D	3.17	136.7	2.40	36.7		33	11.0	2.61	94.5	1.72	-39.4	33		42.3	17	6
PENN VIRG RES	29-1	12/02	1.57D	1.23	-21.7	0.79	-12.6		25	2.0	1.45	-8.0	0.81	-3.0			16.7	3	1
UNDESIGNATED ENERGY			-0.44	0.31	-+	NM	49.2	13	38	19.4	0.11	-+	NM	-+	17	33	110.2	10	
ENERGY PARTNERS	11-0	12/02	-0.44D	0.80	-+	NM	36.5	17	50	11.4	0.31	-+	NM	-+	20	40	88.1	10	
FUEL CELL TECH	0-3	12/01	N/AD	-0.08	N/A		N+			41.2	-0.05	N/A		N+					
GAS			-0.24	1.26	-+	NM	-6.0	17	10	10.7	1.58	-+	NM	-8.5	14	8	14.7	7	3
ATLAS PIPELINE	33-0	12/02	1.54D	2.26	46.8	1.49	N/A	100			2.48	61.0	1.42	N/A	100			9	
CROSSTEX ENERGY	37-7	12/02	N/AD	2.05	N/A		48.6	100		1.4	2.10	N/A		45.8	100		0.0	8	
DELTA NAT GAS	23-1	6/02	1.45D	1.44	-1.0	1.00	-1.0			1.5	1.23	-15.2	0.75	N/A			2.3	3	
DYNEGY INC	3-5	12/02	-0.85D	0.01	-+	NM	-+			644.4	0.14	-+	NM	-47.4	11		69.2	5	6
MARKWEST ENERGY	25-7	12/02	1.28D	1.60	25.3	1.27	7.8			2.9	1.92	50.2	1.33	49.0	25		12.3	12	6
MARKWEST HYDRO	7-0	12/02	-0.30D	-0.50	N-	NM	-VL				0.25	-+	NM	-60.7				15	
SEMCO ENERGY INC	4-4	12/02	0.48D	0.24	-50.7	0.50	-55.6			26.8	0.37	-22.9	0.68	-43.1			30.7	4	1
SYNTROLEUM CORP	3-6	12/02	-1.04D	-0.68	N+	NM	N-		100			0.0		N/A		100			

SECTOR/INDUSTRY/COMPANY	PRICE	ACTUAL FISCAL YEAR	ACTUAL EPS	ESTIMATES-FISCAL YEAR ONE MEAN	FY1 PERCENT CHANGE ACTUAL	FY1 PERCENT CHANGE RELATIVE	FY1 PERCENT CHANGE 6 MO.	FY1 REVISIONS %UP	FY1 REVISIONS %DOWN	FY1 COEFF. OF VAR.	ESTIMATES-FISCAL YEAR TWO MEAN	FY2 PERCENT CHANGE ACTUAL	FY2 PERCENT CHANGE RELATIVE	FY2 PERCENT CHANGE 6 MO.	FY2 REVISIONS %UP	FY2 REVISIONS %DOWN	FY2 COEFF. OF VAR.	ESTIMATED 5 YR. GROWTH RATE MEDIAN	ESTIMATED 5 YR. GROWTH RATE S.D.
TC PIPELINE, LP	32-3	12/02	2.61D	2.59	-0.8	1.00	-0.2	20		4.4	2.64	1.0	0.89	-0.6	20		4.0	4	1
UGI CP	29-6	9/02	1.80D	2.25	25.0	1.27	4.7			0.0	2.31	28.1	1.13	2.4			2.7	6	1
WGL HOLDING INC	27-4	9/02	1.14D	2.13	87.2	1.90	5.0	11		2.3	1.92	68.1	1.49	0.3			6.7	4	1
GAS PIPELINES			0.79	0.83	5.1	1.06	-24.2	3	6	9.8	1.08	37.3	1.21	-11.5	4	4	10.6	11	6
EL PASO CO	7-6	12/02	0.64D	0.28	-56.1	0.44	-70.4		7	37.5	0.53	-16.5	0.74	-44.4		8	30.2	10	6
ENBRIDGE	44-0	12/01	N/AD	1.76	N/A		-0.1			2.2	2.10	N/A		-12.2		33	1.5	8	2
ENBRIDGE ENERGY	48-4	12/02	1.76D	2.12	20.3	1.22	-8.7			9.0	2.41	36.6	1.21	-7.5			5.8	7	3
GULFTERRA ENERGY	40-0	12/02	0.92D	1.67	81.8	1.64	23.2	8		2.4	1.79	94.4	1.72	11.6	8		8.8	8	2
KINDER MORGAN EN	41-7	12/02	1.96D	2.01	2.7	1.04	-1.6	7	7	1.8	2.16	10.3	0.98	-3.2		7	2.8	10	3
KINDER MORGAN	52-4	12/02	2.85D	3.29	15.5	1.17	2.3			0.9	3.67	28.7	1.14	1.2			1.9	15	4
KINDER MORGAN	37-5	12/02	1.86D	2.01	8.1	1.10	3.8			2.6	2.16	16.3	1.03	3.4	25		3.4	10	0
MAGELLAN MIDSTRE	44-2	12/02	3.67D	3.52	-4.2	0.97	5.9		9	2.2	3.51	-4.4	0.84	5.2		9	3.3	10	4
PACIFIC ENERGY	25-1	12/02	1.44D	1.20	-16.4	0.85	1.4			2.0	1.45	0.9	0.89	15.1			13.4	5	5
VALERO LP	42-4	12/02	2.72D	2.99	9.8	1.11	7.9		14	0.7	3.18	16.9	1.03	9.7			2.4	9	3
WILLIAMS COS	8-8	12/02	-0.16D	0.15	-+	NM	-30.6	9	27	55.3	0.42	-+	NM	15.7	15		20.2	10	7
TELEPHONE UTILITIES			1.36	1.38	1.4	1.03	6.0	10	5	3.2	1.42	3.5	0.91	1.5	8	5	8.1	3	6
TELEPHONE UTILITIES			1.07	1.32	23.6	1.25	8.9	7	2	2.2	1.39	30.4	1.15	6.8	4	2	5.9	5	5
ALLTEL CP	47-4	12/02	3.24D	3.20	-1.3	1.00	1.4	9		0.6	3.32	2.3	0.90	1.2	5		2.7	5	3
CENTURYTEL INC	33-7	12/02	2.27D	2.33	2.7	1.04	9.1	6		1.0	2.47	9.0	0.96	5.5	6		3.3	5	4
CINCINNATI BELL	5-4	12/02	-0.46D	0.43	-+	NM	-+	9		8.9	0.46	-+	NM	-+			24.8	8	9
CITIZENS COMM CO	11-3	12/02	-0.42D	0.44	-+	NM	55.1	6		9.1	0.49	-+	NM	20.3	6		13.5	14	6
COMMONWEALTH TEL	41-2	12/02	2.27D	2.46	8.4	1.10	3.6			1.1	2.53	11.6	0.99	0.9		9	3.3	5	12
CT COMM	14-0	12/02	0.54D	0.53	-2.3	0.99	9.4		25	3.2	0.61	12.5	0.99	7.0			10.8	12	14
GEN COMMUNICATIO	8-7	12/02	0.12D	0.27	125.0	2.28	17.4			0.0	0.45	275.0	3.31	21.6			9.4	8	
HICKORY TECH CRP	11-5	12/02	0.58D	0.69	19.0	1.20	15.0			2.5	0.77	32.8	1.17	16.7			2.2	12	5
ITC DELTACOM INC	4-7	12/02	-1.60D	-0.35	N+	NM	N-				0.25	-+	NM	-+					
PRIMUS TELECOM	7-6	12/02	-0.86D	-0.02	N+	NM	N+			0.0	0.47	-+	NM	80.8			21.1		
SPRINT CORP	14-8	12/02	1.36D	1.36	0.3	1.02	-1.5	4		2.2	1.29	-5.1	0.84	-5.6	4		6.0	2	5
SUREWEST	37-2	12/02	0.39D	0.48	23.1	1.25	84.6	33		2.1	0.70	78.6	1.58	-5.4	33		22.5	25	7
TELE & DATA SYS	57-2	12/02	2.50D	1.36	-45.7	0.55	-45.2	22	11	7.7	2.25	-10.0	0.80	-24.6		10	10.6	10	7
US LEC CORP	5-2	12/02	-2.04D	-1.27	N+	NM	N+				-0.68	N+	NM	N+					
AT&T DIVESTITURES			2.37	2.10	-11.2	0.90	2.3	10	4	2.2	2.02	-14.8	0.75	-2.8	7	6	5.7	2	5
A T & T CP	22-3	12/02	1.26D	2.33	84.8	1.87	24.7	11	4	5.2	1.72	36.7	1.21	15.7	11		19.3	-16	14
BELLSOUTH CP	25-4	12/02	2.09D	2.02	-3.5	0.98	8.2	13		2.0	2.00	-4.5	0.84	4.8	11	3	4.5	3	6
METRO ONE TELCOM	4-5	12/02	1.04D	-0.77	-VL	NM	-VL			16.9	-0.36	-VL	NM	-VL			174.1	10	3
RMH TELESERVICES	3-7	9/02	0.23D	-0.32	-VL	NM	-VL				0.30	30.4	1.15	-68.3			51.9	19	16
SBC COMMUN INC	23-4	12/02	2.24D	1.61	-28.2	0.73	-2.8	9	3	3.0	1.57	-29.9	0.62	-9.2	3	13	5.8	2	5
VERIZON COMM	35-4	12/02	3.05D	2.73	-10.4	0.91	-0.3	8	11	1.0	2.69	-11.8	0.78	-3.9	5	10	3.6	3	4
CELLULAR COMMUNICATIONS			-0.26	0.15	-+	NM	249.7	14	8	31.3	0.38	-+	NM	50.5	13	6	33.7	14	16
AIRGATE PCS INC	2-8	9/02	-7.54D	-3.37	N+	NM	N+				-1.83	N+	NM	N+					
ALAMOSA HLDN	4-2	12/02	-1.20D	-1.51	N-	NM	N-		100		-0.32	N+	NM	N-	100				

	A	B	C	D	E	F	G	H	I	J
1	GDP Growth 1/23/03									
2	EIA Forecasts of GDP Growth, from *Annual Energy Outlook*									
3										
4		Period	Year-by Year			Inferred	Growth	Nominal		
5	Date of	Wanted	Forecasts				Rates	Growth		
6	forecast	to F'cast						Rate		
7	Published							Forecast		
8										
9										
10										
11										
12										
13	Jan-03	2008-2020	2007	2025						
14		Real GDP	11017	18917			3.05%	5.76%		
15		Deflator	1.242	1.981			2.63%			
16										

	K	L	M	N	O	P	Q	R	S	T	U	V	W	X
1											Exhibit No. ___		(JPW-GDP)	
2	DRI Forecasts						WEFA Forecasts							
3														
4	Date	Period	Year-by		Nominal		Date	Period			Nominal		Forecast	
5	of F'cast	Wanted	Year		Growth		of F'cast	Wanted			Growth		Average	Date
6		to F'cast	Forecasts		Rate			to F'cast			Rate		of 1, 2 or 3	forecast
7					Forecast						Forecast		sources	Usable
8														
9	Global Insight	12/2007-	12/2007	12/2027										
10	Nov. 2002	12/2027	13896	44378	5.98%									
11		GDP												
12														
13														
14					5.98%									
15													5.87%	Jan-03
16														

AGT

Equity Ratios Allowed by the FERC

		Equity Ratio Allowed
1	Pacific Gas Transmission Co., 62 FERC ¶61,109 (1993) (Cited in 4, 5 & 9)	68.86%
2	Panhandle Eastern Pipeline Co., 71 FERC ¶61,228 (1995) (Cited in 4, 5, 6 & 9)	61.79%
3	Panhandle Eastern Pipeline Company, 74 FERC ¶61,109 (1996) (Cited in 8)	59.97%
4	Williams Natural Gas, 84 FERC ¶61,080 (1998) (Citing 1 & 2 and Cited in 8)	64.29%
5	Opinion No. 414-A, Transcontinental Gas Pipeline Corporation, 84 FERC ¶61,084 (1998) (Citing 1 & 2 and Cited in 7), and	
6	Opinion No. 414-B, Transcontinental Gas Pipeline Corporation, 85 FERC ¶61, (Citing 2 and Cited in 9)	57.58%
7	Williams Natural Gas, 86 FERC ¶61,232 (1999) (Citing 5)	64.29%
8	Northwest Pipeline Corporation 92 FERC ¶61,287 (2000) (Citing 3 & 4)	55.00%
9	Transcontinental Gas Pipeline corporation, 90 FERC 61,279 (2000) (Citing 1, 2	60.20%