BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF DELTA NATURAL)
GAS COMPANY, INC. FOR AN) 2007-00089
ADJUSTMENT OF RATES)

FILING REQUIREMENTS
VOLUME 3 OF 3

FILED IN SUPPORT OF PROPOSED
CHANGES IN RATES

APRIL 20, 2007

RECEIVED
APR 20 2007
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

APPLICATION OF DELTA NATURAL GAS	)	
COMPANY, INC. FOR AN ADJUSTMENT	)	CASE NO. 2007-00089
OF RATES	)	

DIRECT TESTIMONY OF

GLENN R. JENNINGS

AFFIDAVIT

The affiant, Glenn R. Jennings, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089 in the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

Glenn R. Jennings
GLENN R. JENNINGS

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by Glenn R. Jennings, this the 12th day of April, 2007.

My Commission Expires: 6/20/08

Emily P. Bennett
Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. Glenn R. Jennings, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391.

Q. What is your present employment?

A. I am presently employed as Chairman of the Board, President and Chief Executive Officer of Delta Natural Gas Company, Inc.

Q. For what period of time have you been so employed?

A. I was employed by Delta as Treasurer in 1979. I was appointed Vice President - Finance and Treasurer in 1982; Executive Vice President, Treasurer and Chief Operating Officer in 1983; President, Treasurer and Chief Executive Officer in 1985; President and Chief Executive Officer in 1988 and Chairman of the Board, President and Chief Executive Officer in 2005.

Q. Would you briefly describe your education and professional experience?

A. I attended Berea College, Berea, Kentucky, from 1969 to 1972, receiving a B.S. in Business Administration. I have also attended two graduate schools working toward an M.B.A. I am a Certified Public Accountant in the states of Kentucky and Ohio. From 1972 to 1973, I was employed by Ford Motor Company in Cincinnati, Ohio as a production supervisor in a plant that manufactured automotive transmissions. I was employed by the accounting firm of Arthur Andersen & Co. in its Cincinnati, Ohio office from 1973 to 1977, specializing in the utility area. From July, 1977 to January, 1979, I was employed by Berea College as Internal Auditor and Assistant to the Vice President for Finance, during which time I prepared rate cases and testified before the Public Service Commission several times. Since January, 1979, I have been employed by Delta.

I have appeared before the Public Service Commission on numerous occasions on Delta's behalf.

I served 11 years on the Board of Directors of the Kentucky Gas Association (President in 1991-1992). I am a past Chairman (1997-1998) of the Board of Directors of the Southern Gas Association and serve on the Board of Directors of the American Gas Association (Vice-Chairman of Small Member Council and Chairman of the Audit Committee).

Q. Generally what are your duties with Delta?

A. As Chairman of the Board, President and Chief Executive Officer, I have responsibility for all areas of Delta. I supervise the officers of the Company who report to me and are responsible for each of their respective segments of the Company.

Q. Mr. Jennings, will you please summarize for the Commission the historical development of Delta's business?

A. Certainly. Delta is a Kentucky corporation with its principal office at 3617 Lexington Road in Winchester, Kentucky. In 1950, Delta completed its first distribution system, which served approximately 300 customers in Owingsville and Frenchburg. Delta expanded its business until 1977 when it was serving 11,000 customers in relatively small communities in central Kentucky. At that time Delta's only source of gas supply was the interstate system and the Company was not large enough to attract the capital sufficient to continue to provide a high degree of service to our customers. Therefore, the decision was made to expand our business by acquiring gas systems in the gas producing regions in southeastern Kentucky. In October, 1977, we acquired Gas Service Company, Inc., Cumberland Valley Pipe Line Co. and Laurel Valley Pipe Line Company. These companies operated the distribution systems in London, Pineville, Middlesboro, Williamsburg and part of Barbourville, the transmission lines linking the towns, except London, and related gathering lines and gas storage facilities. At that point we began serving an additional 8,500 customers and began utilizing locally produced natural gas and gas storage facilities. In January, 1981, we acquired the assets of Peoples Gas Company of Kentucky, a subsidiary of The Wiser Oil Company, which added approximately 8,700 customers in Corbin, Barbourville, Manchester, Oneida and Burning Springs. In January, 1982, we purchased approximately 57 miles of transmission lines from Wiser which run generally from Manchester to Corbin and London. In 1989, we leased the TranEx pipeline, a 43 mile 8 inch diameter pipeline which extends from Manchester to Richmond, and began operating it as a part of our transmission system. In 1995-1996, we developed and began operating an underground storage field in Bell County. We purchased the TranEx pipeline in 1997. Delta has continued to successfully expand its distribution systems by extending to new areas such as Beattyville in 1992. Delta expanded into Fayette County in 1997 and also acquired the North Middletown distribution system in Bourbon County as well as Annville Gas & Transmission in Jackson County. We also purchased the Mt. Olivet gas system, located in Robertson and Mason Counties, in 1999.

Delta has thus grown to a system of approximately 38,000 customers in primarily rural areas of Kentucky with 5 district offices, two warehouses and approximately 2,500 miles of transmission, distribution, service and gathering pipeline in 23 counties in central and southeastern Kentucky. This includes transmission lines that interconnect with

Richmond, Berea, Manchester, London, Corbin, Middlesboro, Barbourville, Pineville and Williamsburg. In addition, transmission lines interconnect the other communities we serve with each other and/or the sources of gas. The gathering systems are located in Bell, Knox, Whitley and Clay counties in the vicinity of production wells. Delta owns, operates and maintains service lines as well. Also, Delta has three wholly-owned subsidiaries. Two of those companies buy and sell natural gas and one owns production properties.

Delta is a relatively small, independent, investor-owned utility headquartered in Kentucky. Our system is mainly in smaller Kentucky communities or rural areas, and there are no large concentrations of customers. We serve an area in central and southeastern Kentucky that was not otherwise served and provide service to small, rural areas in eastern Kentucky. We continue to consider expansion into eastern Kentucky areas, including acquisition of smaller systems there. We are the only stand-alone, publicly owned, Kentucky-based utility among the larger utilities in the state. We must meet all requirements for a public company, including compliance with the Sarbanes-Oxley Act of 2002, despite our smaller size. Thus, we are faced with a significant challenge to control the upward pressure on rates while still providing our customers with a high degree of service as well as maintaining an adequate return to our shareholders so that we can continue to raise the capital needed. Our general overhead is thus only spread over our rural Kentucky-based operations. Reduced customers and customer conservation has a larger impact on us than on much larger utilities, especially considering the smaller customer density on our system.

Q. Mr. Jennings, are you sponsoring any of the Filing Requirements in this proceeding?

A. Yes, I am sponsoring the following Filing Requirements:

- Reason for a rate adjustment, Section 10(1) (a) 1 under Tab 1
- Articles of Incorporation, Section 10(1) (a) 3 under Tab 1
- Limited Partnership, Section 10(1) (a) 4 under Tab 1
- Certificate of Good Standing, Section 10(1) (a) 5 under Tab 1
- Certificate of Assumed Name, Section 10(1) (a) 6 under Tab 1

Q. Mr. Jennings, please tell the Commission the reason an adjustment in rates is required.

A. In this filing, our rate base, capital and operating costs reflect current and known levels. We based our proposed rates on data for the test year ended December 31, 2006, or as of the end of the test year, and included known facts which are reflected as adjustments consistent with our last rate case. We have proposed a rate design similar to that approved by the Commission in our last case with adjustments to reflect our updated cost of service study as well as current market conditions.

Our last rate filing in 2004 utilized a test year ending December 31, 2003. Thus, by the time rates are expected to be implemented from this case, almost four years will have passed since the test year end for the last case. The rates requested in this filing will update our current rates to reflect current levels of rate base, operating expenses, taxes, depreciation and interest as well as to recover a reasonable return on equity investments.

We are also proposing an adjustment mechanism that will permit this Commission to approve adjustments of our rates proposed in this case in the future to reflect conservation and efficiency gains by our customers. Comparing to the revenues allowed in our last rate case, Delta has experienced significant reductions in earnings as customers have continued to conserve as well as replace equipment with more fuel efficient equipment. This is a national trend as well, as demonstrated by a recent study completed in March, 2007 by Frederick Joutz and Robert P. Trost for the American Gas Association entitled An Economic Analysis of Customer Response to Natural Gas Prices. Delta's experience since our last rate case reflects this trend. Our margin on sales (revenues minus gas costs) and earned return on equity allowed in Case No. 2004-00067, which used a December 31, 2003 test year, compared with the three years after that case demonstrates this:

	Margin	Return
Allowed in Case No. 2004-00067	$21,389,000	10.5%
Actual December 31, 2004	$18,069,000	4.1%
Actual December 31, 2005	$19,916,000	5.6%
Actual December 31, 2006	$18,586,000	3.9%

Q. Mr. Jennings, can you comment upon Delta's competitive environment today and what impact this has upon rate design and other marketing considerations?

A. Yes, I can. We have competition in our service area from many alternate energy sources, including electricity, coal, oil, wood, propane and other natural gas suppliers. We compete directly with several electric utilities, including Kentucky Utilities, various RECCs and municipal systems.

Our larger volume customers with alternate fuels available in the case of interruption could switch to those alternate fuels such as oil or propane at any time. Such customer losses place a greater burden on Delta and all remaining customers. It is advantageous to Delta, and Delta's smaller volume customers, to retain the larger volume load customers. We also need to be competitive for new industrial prospects, since this too will benefit all our customers.

On and off-system transportation are a significant component of our total throughput. We have been physically bypassed in some instances and threatened in others. Thus competitive transportation rates are very important to us. Maintaining our present interruptible transportation rates as well as competitive off-system transportation rates should help to retain our larger volume customers as well as attract new ones.

Q. In developing the proposed rates in this case, how has Delta considered its cost of service study?

A. The cost of service study determined the cost of service and return on rate base for each customer class. In designing our rates we considered the cost of service study, as well as the principles of rate continuity, gradualism and customer acceptance. This should help to keep Delta's rates in its service areas attractive for economic development.

Q. Mr. Jennings, how do the transportation revenues reflected in this rate filing benefit Delta's sales customers?

A. Delta's sales customers benefit from transportation since the revenue provided by on-system and off-system transportation service reduces the revenue requirement otherwise required from Delta's other customers. Delta continues to try to maximize transportation deliveries for others. Our transportation business has increased dramatically in the past few years. As a result, transportation volumes in the test year are approximately 20% more than the levels in our last rate case. We are concerned about whether the test year level of transportation revenues will continue in the future, since continued deliveries are dependent upon many variables, including weather, producers' production capabilities, the level of end-user operations, supply needs, system capabilities, federal regulations and bypass.

Q. Has Delta been impacted in recent years by customer conservation and increased efficiency of equipment?

A. Yes, especially in the past few years as demonstrated on page 6 of my testimony.

Q. What has Delta proposed in this filing to help with that trend?

A. We proposed the Customer Conservation and Efficiency Program to be able to promote efficiency and conservation without being penalized financially. We also proposed the experimental Customer Rate Stabilization mechanism to adjust rates annually at a lesser costs to our customers and to help lessen the impact of efficiency gains and conservation while keeping rates current and stabilizing the annual impacts of any such adjustments to our customers. Both of these proposals are meant to help better align Delta's and our customers' interests.

Q **Do you agree with the return on common equity as recommended by Dr. Blake?**

A. Yes. Delta is small in comparison to major utilities, yet, as an independent, investor-owned company, it must compete in the same financial markets for its new capital. Delta must be able to raise common equity to enable it to continue to issue long-term debt securities. Also, common equity issuance is a necessity in order to be able to continue our required short-term lines of credit, which is now necessary to meet summer construction and storage injection needs.

We are in contact with brokers, analysts, investment bankers, investors, shareholders and market makers on a routine basis to discuss Delta and their concerns as they relate to Delta. Their primary concerns are the stability of dividends, future growth in dividends and stock value and maintenance of an adequate return on common equity to provide for these items. In order to be able to issue and sell debt and equity securities on fair terms, we must be able to maintain reasonable retained earnings over and above our dividend payments to shareholders.

As Dr. Blake states in his testimony, Delta's earnings since our last rate case have been inadequate. This trend continued during 2006 and Delta's December 31, 2006 net income provided an inadequate return on common equity, well below Delta's authorized return. Delta's requested return is fair and reasonable and will produce a reasonable yield to investors and allow us to continue our dividends. Such a return should thus strengthen the shareholders' confidence in investing in Delta's common stock. This will also provide Delta the opportunity to continue to fulfill its future capital needs in the common equity markets at a fair cost to both customers and stockholders.

We have asked for a slightly larger return than Atmos Energy and Columbia Gas of Kentucky are seeking in their recent filings with the Commission. We believe this is reasonable due to Delta's smaller size, rural eastern Kentucky service area and higher relative risk.

Q. Could you please review Delta's current financial condition and financing needs?

A. Yes. Our earnings for calendar 2006, the test year, are not adequate. Financial indicators such as return on common equity and payout ratio indicate that Delta's financial condition needs to improve. We must improve earnings to be able to continue our dividend and we must be able to continue our dividend in order to raise future equity capital effectively.

We utilize short-term debt, along with internally generated cash flow from operations, to meet our construction expenditure needs. We periodically repay these short-term borrowings as capital markets permit and as our needs dictate. In 2006, we refinanced some of our long-term debt and short-term debt with the issuance of long-term debt. Delta had borrowed approximately $17.1 million under its short-term line of credit as of the end of the test period, and our current credit line must be renewed in October, 2007. The continuing availability of this line of credit is closely tied to our ability to refinance those borrowings from time to time. Our continuing ability to raise debt and equity capital, and thus to be able to continue to finance our construction expenditures, is a direct result of our financial stability. An expedient approval of the rates as requested would be fair to both Delta's shareholders and customers and would help to keep our cost of capital as low as possible.

Q. Please describe Delta's response to industry changes that have taken place in the past few years.

A. Delta deals with industry change with the best interests of its customers in mind. Prior to deregulation of natural gas wellhead prices in the 1980s, Delta began transporting for larger volume customers, producers and off-system customers and those additional transportation revenues helped to keep our other rates lower. We have had a mix of supplies from producers, marketers, pipelines and our own supplies and this has helped to balance our supplies and prices and keep our gas costs as low as possible. In order to further respond to the changes, we acquired and developed the Canada Mountain underground natural gas storage field in Bell County, Kentucky. This storage field is a significant factor in meeting our seasonal supply needs. We have continued to seek ways to increase our transportation business to help keep our rates as low as possible to our customers.

We continue to strive to improve productivity and efficiency wherever we can. For example, in fiscal 1999 we had 183 employees who maintained our annual system throughput of approximately 9 bcf. By comparison, in 2006 we had 156 employees maintaining a system throughput exceeding 17 bcf. Thus we maintain a system throughput that has increased since that time by approximately 85%, and we are doing so with approximately 15% fewer employees. We have kept our base rates unchanged for the past 3 years, during a time when inflation has increased by over 9%.

We have a very high level of customer satisfaction. We strive for excellence in customer service, with 100% of our meters being read using automated meter reading devices to provide efficiency, speed, accuracy and actual reads each month for customer bills. Our customer calls are dispatched by Kentucky-based employees in our service area, with knowledge of our customers and service area. We have a well trained and experienced work force of Kentucky-based operations providing our excellent service. Customers make their payments personally to our district offices, or by mail or through direct bank withdrawals for their convenience. Our budget billing program allows customers to smooth out their bill payments. We own, maintain, operate and replace as needed all customer service lines, so our customers do not have that direct responsibility. We try our very best to provide same day service to our customers to meet their schedules and needs in an efficient and effective manner. We also assist in our service area with economic development efforts and work to ensure that our systems are extended to any areas possible to assist in further development that is pursued.

Q. Why is Delta seeking an experimental Customer Rate Stabilization mechanism?

A. Delta is permitted by law to earn a fair return on equity. Partly due to customer conservation and efficiency trends, we have not been able to do so since our last general rate case. This trend is expected to continue, and the current rate setting process does not contemplate this trend and does not allow utilities to adjust rates on a timely, cost effective basis. Thus, we need the proposed mechanism to be able to do this.

We proposed this innovative, experimental Customer Rate Stabilization mechanism to provide for more cost-effective annual reviews of Delta's cost of operations to ensure customers more stable and equitable rates. As a part of the CRS, the Commission will review Delta's financial performance for the past year and determine rates for the next year. A true-up is included to adjust each year for the previous year's experience. The proposed rates would be subject to review by the Commission. The Attorney General may participate in the review if he wishes. Final authority, as it now does, would reside with the Commission in accordance with the timetable set out in the CRS. The CRS mechanism is proposed for an experimental period of five years, with a review of the CRS to be filed by Delta with the fifth year filing.

The CRS mechanism would thus provide for annual consistent, financially transparent reviews of rates that would be conducted at a low cost and would provide more stable rates and customer rate protection. The mechanism would review the Company's financial performance for the past year and set the proper rates for the next year. If the next year varied from what was planned, a simple true-up at the end of the year would assure that customers' rates would be fair.

The CSR mechanism would provide transparency of Delta's annual financial performance and ensure that rates paid by our customers will provide only the revenue needed to achieve the rate of return authorized in Delta's most recent general rate case. The CRS would apply the principles and rules that are used to set rates in Kentucky on an annual basis to test the existing rates and adjust them as necessary. This would ensure that Delta's rates were always fair, just and reasonable as the rates adjusted in the annual evaluation would be set to earn the return allowed by the Commission.

Q. Mr. Jennings, what impact will Delta's proposed experimental Customer Rate Stabilization mechanism have on Delta's customers?

A. The proposed rate stabilization tariff will significantly reduce the costs now required to adjust rates because of the simplified annual filing procedure. It will stabilize rate adjustments by providing for annual adjustments in rates and by keeping rates current with smaller adjustments each year in keeping with the principle of gradualism. It will prevent continued potential over-earning situations since, if earnings were to exceed allowed amounts, then rates will be adjusted downward for the next year to rectify this. This will also provide for rates to be adjusted annually to reflect the impacts of conservation and efficiency gains by customers, thus better aligning Delta's and our customers' interests. There is no impact on Delta's required return on equity because the mechanism does not change the return on equity approved in the last general rate case. Delta, like all utilities in Kentucky, has the ability now to file general rate cases as frequently as annually to request adjustments in rates. If the proposed rate stabilization tariff is not approved, Delta will have to do so to address the erosion of earnings. This proposed tariff will reduce the cost to Delta's customers of such annual adjustments.

Atmos Energy and Delta have both now proposed such a mechanism in Kentucky. Other utilities in other jurisdictions have proposed or adopted various forms of rate stabilization. Delta's proposed mechanism is patterned after the one implemented by the legislature in South Carolina. It is also similar to the mechanism that has been utilized successfully for many years in Alabama. Other states where utilities and commissions have addressed or are addressing similar concerns, including demand side management, decoupling revenues from volumes and other means to address declining sales due to conservation and efficiency, include Indiana, North Carolina, Oregon, New Mexico, Utah, Louisiana, New Jersey, Missouri, California, Ohio, Maryland, Virginia, Minnesota and Idaho.

Q. Has Delta considered the costs that could be required by the Commission and Attorney General in reviewing filings under the proposed experimental Customer Rate Stabilization mechanism?

A. Yes. Although we cannot determine the extent of review and amount of such potential costs of their reviews, we have included a provision to provide for incremental cost reimbursement for them if they require that. If Delta is required to file annual general rate cases, we believe that cost on the Company, its customers, the Commission and the Attorney General will be substantially above the cost of annual reviews under the CRS mechanism. There should in fact be less staff and outside resources needed by the Commission and the Attorney General to review the annual CRS filings in comparison to the internal and external costs of fully litigated annual general rate cases. This will be savings for all participants in the rate setting process.

Q. The Commission's Order in Delta's last rate case, Case No.2004-00067, directed Delta to have a study of its directors' compensation completed. Has such a study been done?

A. Yes. Delta engaged Mercer Human Resource Consulting to complete a study of its directors' compensation and a copy of its study, dated November 3, 2006, is attached to this testimony as Exhibit GRJ-1. Delta made adjustments to its directors' compensation, and reduced its number of directors, in latter 2006.

Q. Does this conclude your testimony at this time?

A. Yes.

Exhibit GRJ-1

MERCER
Human Resource Consulting

November 3, 2006

Review of Outside Director Compensation
Delta Natural Gas Company, Inc.

Todd Krauser
Atlanta, GA

Background

INTRODUCTION

- Mercer has been asked to review the outside director compensation program for Delta Natural Gas Company, Inc. (Delta or the Company)
- Mercer has compared Delta's current program to a comparison group of industry peers
  - The peer group consists of eight organizations with median revenues of $177 million (individual company details in appendix)

EXECUTIVE SUMMARY

- The current level of compensation provided to Delta's outside directors is below the peer group 25th percentile
- Although Delta's program structure differs slightly from market practices (i.e., the majority of companies use "per meeting" fees as opposed to larger committee retainers), the only recommended structural change relates to the discontinuation of participation in cash performance bonuses in the future
- Given Delta's conservative compensation philosophy and reduced level of meeting activity versus peers, Mercer's recommendation to increase the cash retainer improves competitiveness and provides an appropriate level of compensation

General Industry Market Trends

General Industry Market Trends

- **Some of the key <u>general industry</u> trends we have observed in the marketplace include:**

	Market Trends
Program Structure	■ Simplified design – Meeting fees folded into annual retainer – Retainer levels increased to reflect greater time commitment – Committee chair retainer have increased, particularly premiums for audit and compensation committees
Long-Term Incentives	■ Options and other performance incentives that allow shorter-term gains are generally viewed as inconsistent with fiduciary responsibility ■ Stock grants viewed as more aligned with shareholder position
Mix of Cash and Equity	■ Closer balance between cash and equity
Stock Ownership Guidelines	■ Significant increase in prevalence

Competitive Practices

Methodology

- **Cash Compensation** is defined as the sum of annual retainers, meeting fees and annual service fees paid for board and committee service
- **Equity Compensation** is defined as the grant date value of equity awards
- **Total Direct Compensation** is defined as the sum of cash and equity compensation
- In order to facilitate meaningful and consistent comparison across companies, several assumptions were made in calculating total direct compensation levels:
  - Each director attends all board meetings, is a member of two committees, and attends ten committee meetings (5 of each committee)
  - Each Director is a chairman of one of these committees (not the Audit or Compensation Committee)
  - Option grants were valued as of the grant date using the Black-Scholes option pricing model
  - For the peer companies that provide an initial equity award upon election to the board, these "election" grant values were annualized over a six-year period

Delta's Current Program

- The estimation of Delta's current annual compensation package is shown below
- Since Delta does not provide equity grants, total cash and total direct compensation are the same
- Our estimate below represents the total pay for the chair of the compensation committee
  - Board members not serving as chair of a committee will earn less, while the Audit Chair will earn more

Pay Element	Monthly Value	Annualized Value
Cash Retainer	$900	$10,800
Chair Retainer (all committees) – premium in addition to regular retainer	$300	$3,600
Committee Service Retainer		
Audit	$400	$4,800
Compensation	$300	$3,600
Cash Performance Bonus (average)	-	$4,500
Estimated Total Cash & Total Direct Compensation	-	**$22,500**

Industry Practices

Program Structure

- **Cash Compensation:** All industry companies provide both an annual cash retainer for board service as well as a retainer for chairing a committee. However, while Delta provides an additional retainer for committee service, the more prevalent practice is to provide cash compensation via a "per meeting" fee arrangement
- **Equity Compensation:** Equity compensation is only provided by one-third of the industry peers (this is particularly noteworthy as this group differs considerably from general industry practices where equity compensation is an integral component of total pay)

Company	Annual Cash Retainer	Board Meeting Fees	Committee Meeting Fees	Committee Chair Retainer	Committee Member Retainer	Stock Options	Full Value Shares
Semco Energy Inc	✔			✔	✔		✔
Cascade Natural Gas Corp	✔	✔	✔	✔	✔	✔	
Chesapeake Utilities Corp	✔	✔	✔	✔			✔
Northwest Natural Gas Co	✔	✔	✔	✔			
Energysouth Inc	✔	✔	✔	✔			
Rgc Resources Inc	✔	✔	✔	✔			
Energy West Inc	✔	✔	✔	✔			
Corning Natural Gas Corp	✔	✔		✔	✔		
% of companies	**100%**	**88%**	**75%**	**100%**	**38%**	**13%**	**25%**

Delta Natural Gas Co Inc	✔			✔	✔		

Competitive Assessment

Delta Relative to Industry Peer Group

- Total cash compensation is slightly below the 25^{th} percentile of the peer group (i.e., 89% of this market data point)
- Since some companies provide equity compensation, positioning of total direct compensation is reduced, and falls further below the 25th percentile (i.e., competitiveness is reduced to 85%)

Pay Element	Delta	Peer Group 25th %ile	Peer Group 50th %ile	Peer Group 75th %ile	Market Index 25th %ile	Market Index 50th %ile	Market Index 75th %ile
Total Cash Comp	$22,500	$25,338	$30,628	$39,875	89%	73%	56%
Equity Comp	$0	$0	$0	$8,516	na	na	na
Total Direct Comp	**$22,500**	**$26,591**	**$33,250**	**$58,206**	**85%**	**68%**	**39%**

Market Index is a ratio of Delta's pay element versus the peer group percentile data point

A ratio of 100% indicates full competitiveness

- Given the relatively small sample size associated with Delta's peer group (8 companies) Mercer also reviewed data from a national compensation survey in order to validate the market information
  - Director pay data obtained from the *National Association of Corporate Directors 2006 Director Compensation Report* revealed pay levels in excess of the peer group for similarly-sized companies both in general industry as well as the utilities/energy industry
  - Therefore, Mercer is comfortable with the peer group data as a fair and reasonable data source

Cash Compensation

- In addition to "below 25th percentile" estimated total cash compensation, Delta's program structure differs from market norms in the following ways:
  - Prevalent practice is to provide meeting fees for board and committee service in addition to annual retainer
  - For the three companies that grant committee retainers, those organizations provide either (a) larger Board service retainers than Delta or (b) smaller Board service retainers plus board service meeting fees in order to maintain competitive cash compensation
  - No organizations compensate directors via cash incentives

Cash Compensation	Delta	Peer Group 25th %ile	Peer Group 50th %ile	Peer Group 75th %ile
Retainer	$10,800	$6,750	$12,000	$22,250
Board Meeting Fee	-	$650	$1,000	$1,250
Committee Meeting Fee	-	$563	$775	$950
Committee Meeting Retainer	$3,600	$1,500	$2,000	$4,000
Chair Retainers:				
Audit	$8,400	$2,750	$4,878	$8,125
Compensation	$7,200	$1,875	$3,878	$5,000
Governance	-	$1,500	$3,878	$4,939
Cash Performance Bonus	$4,500	na	na	na
Estimated Total Cash Comp	**$22,500**	**$25,338**	**$30,628**	**$39,875**

Activity Level

- The level of activity relating to the number of board and committee meetings impacts total compensation considerably
- The majority of industry peer companies provide “per meeting” fees in order to capture the time dedicated to serving the company
  - However, as noted previously, general industry trends indicate many companies are choosing to pay one large retainer in order to simplify the program and compensate directors for the expected time commitment
- Based on the most recent level of activity reported, Delta has fewer board and committee meetings than its peers
  - Thus we would expect Delta’s pay levels to be lower as a result

# of Meetings	Delta	Peer Group 25th %ile	Peer Group 50th %ile	Peer Group 75th %ile
Board	4	7	8	9
Audit Committee	4	5	7	9
Compensation Committee	3	2	4	6

Recommendations

Even with the recommended increase to $27,200, 5 of the 8 peers provide higher levels of director pay. However, given Delta's level of meeting activity, this remains appropriate

Cash Compensation:

- Mercer's recommendation accomplishes the following objectives:
  - Increases market competitiveness by targeting annual compensation between the peer group 25th and 50th percentiles (i.e., approximately $25,000 to $30,000)
  - Removes the annual cash performance bonus
- Increasing the annual retainer would be the simplest approach to accomplishing the desired objectives
- Alternatively, Delta could adopt a more traditional program of "per meeting fees" for committee and board service, however if the current program format accomplishes the needs of the organization, there is no need for change

Equity Compensation:

- Although equity compensation is generally an integral component of director pay, the lack of prevalence demonstrated by peers and Delta's preference for cash signal that cash compensation may be the best way to attract and retain director talent

Pay Element	Current Delta Program	Proposed	% Change
Annual Retainer	$10,800	$20,000	85%
Committee Chair Retainers			
Audit	$8,400	$8,400	0%
Compensation	$7,200	$7,200	0%
Committee Retainer			
Audit	$3,600	$3,600	0%
Compensation	$3,600	$3,600	0%
Cash Performance Bonus	$4,500	$0	-100%
Estimated Total Cash	**$22,500**	**$27,200**	**21%**
Estimated Total Equity	**$0**	**$0**	0%
Estimated Total Direct Comp	**$22,500**	**$27,200**	**21%**

Appendix

Appendix
Industry Peer Group

Company Name	Ticker	Industry	State	# Employees	Sales $mm	Sep 2006 Market Value $mm
SEMCO ENERGY INC	SEN	Natural Gas Distribution	MI	566	$615.1	$199.5
CASCADE NATURAL GAS CORP	CGC	Natural Gas Distribution	WA	375	$326.5	$300.2
CHESAPEAKE UTILITIES CORP	CPK	Natural Gas Transmis & Distr	DE	423	$229.6	$179.4
NORTHWEST NATURAL GAS CO	NWN	Natural Gas Distribution	OR	1,305	$910.5	$1,082.1
ENERGYSOUTH INC	ENSI	Petroleum,Ex Bulk Statn-Whsl	AL	261	$124.6	$267.9
RGC RESOURCES INC	RGCO	Natural Gas Distribution	VA	137	$121.6	$55.2
ENERGY WEST INC	EWST	Natural Gas Distribution	MT	100	$84.3	$32.4
CORNING NATURAL GAS CORP	3CNIG	Natural Gas Transmis & Distr	NY	60	$22.9	$8.1
count=8		***75th Percentile***		***459***	***$398.7***	***$276.0***
		Median		***318***	***$177.1***	***$189.5***
		25th Percentile		***128***	***$112.3***	***$49.5***
DELTA NATURAL GAS CO INC	**DGAS**	**Natural Gas Transmis & Distr**	**KY**	**156**	**$117.2**	**$81.6**

Appendix
Company Detail – Industry Peer Group

Company	Number of Directors	Retainer Fee	BOD Mtg Fee	# of BOD Mtgs	Cmte Member Retainer	Cmte Member Mtg Fee	Committee Chair Retainers				Total Cash Comp (TAC)[1]	Total Full Value Shares ($)	Total Stock Options ($)	Total Equity Value	Total Direct Comp (TDC)[2]
							Audit	Comp	N&G	Other					
Semco Energy Inc	9	$35,000		8	$2,000		$26,000	$16,000	$10,000	$10,000	$47,000	$42,000		$42,000	$89,000
Cascade Natural Gas Corp	9	$5,000	$500	9	$6,000	$500	$7,500	$5,000		$5,000	$21,250		$5,014	$5,014	$26,264
Chesapeake Utilities Corp	10	$12,000	$1,000	8		$1,000	$4,755	$4,755	$4,755		$32,255	$19,020		$19,020	$51,275
Northwest Natural Gas Co	11	$55,000	$1,500	6		$1,000	$10,000	$5,000	$5,000	$5,000	$79,000			$0	$79,000
Energysouth Inc	11	$18,000	$1,000	5		$500	$2,000	$2,000	$1,000	$1,000	$29,000			$0	$29,000
Rgc Resources Inc	9	$12,000	$800	9		$800	$3,000	$1,000	$1,000		$26,700			$0	$26,700
Energy West Inc	7	$6,000	$1,500	14		$750	$5,000	$3,000	$3,000		$37,500			$0	$37,500
Corning Natural Gas Corp	5	$7,000	$500	5	$1,000		$1,500	$1,500		$1,500	$12,000			$0	$12,000
75th Percentile	10	$22,250	$1,250	9	$4,000	$950	$8,125	$5,000	$4,939	$5,000	$39,875	$36,255	$5,014	$8,516	$58,206
Median	**9**	**$12,000**	**$1,000**	**8**	**$2,000**	**$775**	**$4,878**	**$3,878**	**$3,878**	**$5,000**	**$30,628**	**$30,510**	**$5,014**	**$0**	**$33,250**
25th Percentile	9	$6,750	$650	6	$1,500	$563	$2,750	$1,875	$1,500	$1,500	$25,338	$24,765	$5,014	$0	$26,591
Average	9	$18,750	$971	8	$3,000	$758	$7,469	$4,782	$4,126	$4,500	$35,588	$30,510	$5,014	$8,254	$43,842
Prevalence (#)	**8**	**8**	**7**	**8**	**3**	**6**	**8**	**8**	**6**	**5**	**8**	**2**	**1**	**3**	**8**
Prevalence (%)	**100%**	**100%**	**88%**	**100%**	**38%**	**75%**	**100%**	**100%**	**75%**	**63%**	**100%**	**25%**	**13%**	**38%**	**100%**
Delta Natural Gas Co Inc	**10**	**$10,800**	**-**	**4**	**$3,600**	**-**	**$8,400**	**$7,200**	**-**	**-**	**$22,500**	**-**	**-**	**$0**	**$22,500**
DGAS Percent Rank		**39%**	**-**		**100%**	**-**	**77%**	**89%**	**-**	**-**	**18%**	**-**	**-**	**-**	**11%**

[1] Total Annual Compensation (TAC) is defined as the sum of standard annual retainers paid in cash or shares, meeting fees and annual service fees paid for board and committee service. To facilitate meaningful comparison across companies, the following TAC assumptions were employed: each director attends all company board meetings; is a member of 2 committees; attends 10 committee meetings (5 of each committee); and is a Chairman of 1 Committee. Note that we assume that the typical director is not a member of the Audit or Compensation Committees.

[2] Total Direct Compensation (TDC) includes total annual compensation plus the annualized value of equity grants. (Election equity grants annualized over a 6 year assumed term.)

RECEIVED
APR 20 2007
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL	)	
GAS COMPANY, INC. FOR AN	)	**CASE NO. 2007-00089**
ADJUSTMENT OF RATES	)	

DIRECT TESTIMONY OF

JOHN B. BROWN

AFFIDAVIT

The affiant, John B. Brown, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, In the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

John B. Brown
JOHN B. BROWN

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by John B. Brown, this the 17th day of April, 2007.

My Commission Expires: 6/20/08

Emily P. Bennett
Notary Public, State at Large, Kentucky

Q. Please state your name and business address.

A. John B. Brown, Delta Natural Gas Company, Inc., 3617 Lexington Road, Winchester, Kentucky 40391.

Q. What is your present employment?

A. I am an accountant, presently employed by Delta as its Vice President – Controller and Acting Chief Financial Officer.

Q. For what period of time have you been so employed?

A. I was employed by Delta as Manager – Accounting & Finance in April of 1995. I was appointed Controller in March of 1999 and promoted to Vice President – Controller and Assistant Secretary in November, 2005. I was named Acting Chief Financial Officer in February, 2007.

Q. Would you briefly describe your education and professional experience?

A. I attended Asbury College, Wilmore, Kentucky, from 1985 to 1989, receiving B.A. degrees in accounting and business management with a minor in computer science. I received an MBA degree from the University of Kentucky in 2000. I am a Certified Public Accountant in the state of Kentucky. I was employed by the accounting firm of Arthur Andersen LLP in its Louisville, Kentucky office from 1989 to 1995, specializing in the utility area. Since April, 1995, I have been employed by Delta.

Q. Generally what are your duties with Delta?

A. I direct the operations of the Accounting and Information Technology departments. My duties include the maintenance of proper books and accounts, property records and the like; the preparation of periodic financial statements and reports; the proper and timely billing and maintenance of customer accounts; the timely filing of tax reports including sales, property and income and the overall supervision of the company's financial records. I coordinate the preparation and filing of reports to the Securities and Exchange Commission and stockholders. Delta retains Deloitte & Touche LLP, independent registered public accounting firm, with whom I work on a routine basis. I have served as a financial witness in Delta's three most recent rate cases.

Q. Are you generally familiar with the business affairs of Delta?

A. Yes, I am.

Q. Please briefly summarize the scope of your testimony.

A. In my testimony, I sponsor all of the rate application amounts from the books and records of the Company. In that regard I am sponsoring the following filing requirements:

• Most Recent Annual Reports	Section 10(1)(a)2	Tab 2
• Describe and Explain Adjustments	Section 10(6)(a)	Tab 20
• Revenue Requirements Determination	Section 10(6)(h)	Tab 27
• Reconcile Rate Base & Capitalization	Section 10(6)(i)	Tab 28
• Current Chart of Accounts	Section 10(6)(j)	Tab 29
• FERC Form 1 and Form 2	Section 10(6)(m)	Tab 32
• Computer Software, Hardware, etc.	Section 10(6)(o)	Tab 34
• Stock or Bond Prospectuses	Section10(6)(p)	Tab 35
• Annual Reports to Shareholders	Section 10(6)(q)	Tab 36
• Monthly Managerial Reports	Section 10(6)(r)	Tab 37
• SEC Reports (10Ks, 10Qs, and 8Ks)	Section 10(6)(s)	Tab 38
• Affiliate, et. al., Allocations/Charges	Section 10(6)(t)	Tab 39
• Financial Statements with Adjustments	Section 10(7)(a)	Tab 42

- Capital Construction Budget — Section 10(7)(b) — Tab 43
- Pro Forma Adjustment – Plant — Section 10(7)(c) — Tab 44
- Pro Forma Adjustments – Operating — Section 10(7)(d) — Tab 45

Q. Do you adopt the Filing Requirements you just identified, and do you make them part of your testimony?

A. Yes.

Q. Regarding Tab 2, are Delta's annual reports on file with the Kentucky Public Service Commission?

A. Yes, Delta's annual reports, including the annual report filed under the FERC Form 2 format for the calendar year 2006 are on file with the Kentucky Public Service Commission in accordance with KAR 5:006, Section 3(1).

Q. Have you provided a complete description and quantified explanation for all proposed adjustments, as instructed in Section 10(6)(a)?

A. Yes. In Tab 20, I have described each adjustment that is shown in Tab 42 for FR Section 10(7)(a). Further detail for certain of the adjustments are found in Tab 27 for FR 10(6)(h) as discussed below. The attached workpapers, together with the description of the adjustments, provide the description and explanation of proposed adjustments required.

Q. Please explain Tab 27, the determination of the revenue requirement.

A. Tab 27 contains the nine schedules of the revenue requirement study and supporting workpapers. Schedule 2 shows the calculation of revenue at present rates and contains the bill frequency analysis required. The supporting workpapers present the calculation of the proposed adjustments included in the revenue deficiency study.

Q. What is the amount of the revenue deficiency?

A. The amount of revenue deficiency to be recovered by proposed rates is $5,641,597 and is shown in Schedule 1. The deficiency of $5,641,597 is calculated by comparing the total cost of service to the revenues at present rates. This revenue deficiency requires a rate increase of approximately 9.25% of normalized revenues. Schedules 2 through 9 present the components of the cost of service.

Q. Briefly describe Schedules 2 through 9.

A. These Schedules present more detail related to the test year actual data and adjustments which were made to arrive at the revenue deficiency.

Q. Please explain Schedule 2.

A. Schedule 2 shows actual billing determinants for the twelve months ended December 31, 2006 and the proposed adjustments to the billing determinants. Schedule 2 also shows the calculation of gas cost using Delta's current GCR effective February 1, 2007. The amount of gas cost recovery included in present rates is applied to the adjusted volumes.

Q. Does Schedule 2 include a proposed increase due to miscellaneous revenue?

A. Yes. We are proposing a $79,309 increase in miscellaneous revenue. This projected increase is shown assuming the following changes in our miscellaneous fees in Mr. Seelye's Exhibit 4.

	Present	Proposed
Reconnect Charge	$48	$60
Bad Debt Charge	$10	$15
Collection Charge	$15	$20

The proposed increases in miscellaneous charges are reasonable based upon the estimated cost of performing each of these duties as reflected in the cost study set forth in Exhibit JB 1.

Q. Have you included an adjustment for year end customers in Schedule 2?

A. No. While Mr. Seelye prepared a calculation of Number of Customers at the End of the Test Year in Section V of his testimony, we believed that it was not appropriate to apply it to the test year, in light of our history of shrinking customer base over the last five years as reflected in Exhibit JB 2. Not only does the exhibit show that our number of retail customers has decreased, but it demonstrates that our annual usage and usage per customer have also declined.

Q. Your present retail and on-system transportation rates are stated in Mcf. Why are your proposed rates for these classes stated in Ccf?

A. Our meter reads are recorded in Ccfs and our billing system calculates bills and maintains history in Ccfs. Because our tariff rates are stated in Mcfs, we show usage on customer bills in tenths of Mcfs. Our employees thus communicate with customers in Mcfs while our meter reading and billing system utilize Ccfs. Changing the rates to Ccfs will provide for all aspects of metering, billing and rates to be on the same basis, that being Ccfs.

Q. Please explain Schedule 3.

A. Schedule 3 shows actual operation and maintenance expenses for the twelve months ended December 31, 2006 and the adjustments to reflect changes which were known and measurable with reasonable accuracy during the preparation of this filing. Therefore this filing includes only those operating expenses which the Company is actually incurring or will incur. The source for the actual test year costs is the Company's books and records.

Q. Please briefly describe these adjustments.

A. The payroll adjustment normalizes for wage increases given July 1, 2006. Accounts disallowed in Case No. 2004-00067 are removed. The estimated rate case expense is being amortized over three years, which is consistent with the treatment of this item in our last rate case.

Q. Do you believe that other than for these adjustments, the test year is representative with respect to operations and maintenance expenses?

A. While the results of a test year will never perfectly predict expenses in subsequent years, we believe that our 2006 test year, as adjusted and taken as a whole, is a conservative representation of our expenses in subsequent years.

Q. What basis do you have for stating that the Pro Forma expenses are conservatively stated?

A. I have identified four accounts that I believe will be significantly higher subsequent to the test year.

Q What are those accounts?

A. Our largest area of exposure relates to our 2006 Kentucky Property Tax Assessment. The State of Kentucky has set our 2006 assessment at a level that would increase our annualized tax expense to approximately $1,000,000 above the expenses recorded in our test year. We have appealed the assessment and intend to vigorously defend our position that the increase has no merit. Delta can clearly not absorb such an annual increase and will be forced to include recovery of this cost in rates if the assessment is not changed.. Hopefully, the protest will be resolved prior to the completion of this rate proceeding so that the Commission can reflect the actual 2006 property taxes as assessed by the Kentucky Revenue Cabinet in the final Rate Order.

Q. Are there other accounts that you believe may be understated in the test year?

A. Yes. One such account is medical coverage. Test year medical coverage expense, at $985,273, is at the lowest level in six years. In an environment of continuing increases in health care costs, it is unrealistic to believe that costs will continue at this low level. The comparable figure for calendar 2005 was $1,347,871. So, that is a $362,598 shortfall in the test year if expenses return to the 2005 level.

Another such item is uncollectible accounts at $484,710, the lowest level in three years. If this item returns to its 2005 level, the test year will prove to be $116,913 understated.

Legal expenses were also at a six year low at $28,405 for the test year. During calendar 2005, our legal expenses were $132,682.

Q. Knowing that these three accounts are low in the test year, why are you not proposing pro forma adjustments with respect to these items?

A. By keeping our pro forma adjustments to a minimum, we encourage the Commission to utilize the historical test year. While some accounts may trend down in subsequent years due to the normal course of business, others may be understated compared to future levels. In addition, while we believe that these expenses will increase, the amount of that increase is neither known or measurable. We encourage the Commission not to disallow prudent costs incurred during the historical test year when the level of any alleged future decrease is neither known or measurable.

Q. Please describe Schedule 4.

A. Schedule 4 shows depreciation and amortization expense. Actual expenses are adjusted to reflect the test year end level of plant investment. The rates used are those from the Depreciation Study presented by W. Steven Seelye in his testimony.

Q. What adjustments were made to taxes other than income taxes?

A. Schedule 5 shows taxes other than income taxes. Payroll taxes were adjusted to correspond to the adjusted wage levels.

Q. Please describe Schedule 6.

A. Schedule 6 shows rate base and required return. The total rate base is the investment attributable to Delta's system only, excluding Delta's subsidiary companies. Cash requirements are included at one-eighth of operation and maintenance expenses excluding purchased gas cost. Prepayments, materials and supplies and gas in storage were included using a 13 month average which is consistent with the treatment in our last rate case.

Q. Please explain Schedule 7.

A. Schedule 7 shows income taxes. The tax expense is calculated based on the required after tax equity return and a combined tax rate of 37.960 percent. The 37.960 percent tax rate is the result of combining the 34 percent federal rate with the state income tax rate of 6 percent as computed on Schedule 7.1. The reduction in the state income tax rate to 6 percent applies to Delta beginning July, 2007.

Q. Please describe Schedule 8.

A. Schedule 8 shows the calculation of Delta's overall cost rate for capital which is 8.867 percent.

Q. What cost rates are used for debt capital in the calculation of the overall cost of capital?

A. Delta's embedded cost of long-term debt as of the end of December, 2006, which is 6.814 percent, was used for long-term debt. The current rate of 6.487 percent as of April 1, 2007 was used for short-term debt.

Q. What is the requested cost of equity capital?

A. I used 12.1% on the adjusted capital structure as recommended by Dr. Blake in his testimony.

Q. Please explain Tab 28, the reconciliation of rate base and capital used to determine its revenue requirements required by Section 10(6)(i).

A. Tab 28 Section 10(6)(i) refers to the reconciliation in Tab 42 on Schedule 1 for Section 10(7)(a).

Q. Regarding Tab 39, did Delta have any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years?

A. No.

Q. Does this conclude your testimony at this time?

A. Yes.

DELTA NAT AL GAS CO., INC.
Special Charge Cost Study
Test Year Ended December 31, 2006

		RECONNECT-DISCONNECT		COLLECTION		BAD CHECK	
		HOURS	AMOUNT/ HR	HOURS	AMOUNT/ HR	HOURS	AMOUNT/ HR
I.	Field Expense						
	Labor (1) (2)	1.5	$ 37.71	0.5	$ 12.57	0	$ -
II.	Clerical & Office Expense (3)						
	Supplies/ postage		3.00		3.00		3.00
	Other charges - bank fees, etc.						10.00
	Labor (4)	1.5	$ 28.52	0.5	$ 9.51	0.25	$ 4.75
III.	Miscellaneous Expense (5)						
	Transportation (6)	1.5	$ 6.55	0.5	$ 2.18		$ -
	TOTAL EXPENSE		$ 75.78		$ 27.26		$ 17.75

DELTA NATURAL GAS CO., INC.
Customer Count and Usage
Five Years Ended December 2006

Exhibit JB 2

CUSTOMERS BILLED IN DECEMBER

	2006	2005	2004	2003	2002
Residential	32,511	33,323	33,691	34,100	34,479
Small Non-Residential	4,449	4,513	4,545	4,629	4,667
Large Non-Residential	868	858	843	872	872
Interruptible	8	8	9	9	9
Delta Natural Retail	37,836	38,702	39,088	39,610	40,027

USAGE BILLED CALENDAR YEAR

	2006	2005	2004	2003	2002
Residential	1,779,377	2,036,700	2,100,518	2,293,335	2,266,493
Small Non-Residential	544,497	604,106	630,092	697,273	667,590
Large Non-Residential	888,907	922,886	940,845	985,231	936,257
Interruptible	35,216	41,530	47,309	51,349	44,570
Delta Natural Retail	3,247,997	3,605,222	3,718,764	4,027,188	3,914,910

USAGE PER YEAREND CUSTOMERS

	2006	2005	2004	2003	2002
Residential	54.7	61.1	62.3	67.3	65.7
Small Non-Residential	122.4	133.9	138.6	150.6	143.0
Large Non-Residential	1,024.1	1,075.6	1,116.1	1,129.9	1,073.7
Interruptible	4,402.0	5,191.3	5,256.6	5,705.4	4,952.2
Delta Natural Retail	85.8	93.2	95.1	101.7	97.8

RECEIVED

APR 20 2007

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL	)	
GAS COMPANY, INC. FOR AN	)	**CASE NO. 2007-00089**
ADJUSTMENT OF RATES	)	

DIRECT TESTIMONY OF

MATTHEW D. WESOLOSKY

AFFIDAVIT

The affiant, Matthew D. Wesolosky, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, in the Matter of: Application of Delta Natural Gas Company, Inc. for an Adjustment of Rates, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

MATTHEW D. WESOLOSKY

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by Matthew Wesolosky, this the 17th day of April, 2007.

My Commission Expires: 6/20/08

Emily P. Bennett
Notary Public, State at Large, Kentucky

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Wesolosky. My business address is 3617 Lexington Road, Winchester, Kentucky, 40391.

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

A. I am employed by Delta Natural Gas Company, Inc. as its Manager – Internal Control.

Q. Please describe your professional and educational background.

A. I received a Bachelors of Science in Accounting from the University of Kentucky in 1999. I am a Certified Public Accountant in the State of Kentucky. From 1998 through 2001, I worked at Delta as the Accounting Systems Analyst/Coordinator. From 2001 through 2005 I worked in public accounting. From 2003 through 2005 I worked with PricewaterhouseCoopers specializing in the utilities industry. Beginning in 2005 through present I have been employed by Delta as the Manager – Internal Control.

Q. Generally, what are your duties with respect to Delta?

A. I am primarily responsible for the monitoring and evaluation of Delta's internal controls. I directly report to and act as an agent on behalf of Delta's Audit Committee to assist in the Committee's oversight of Delta's corporate governance. I assist in directing the Company's programs for compliance under Section 404 of the Sarbanes-Oxley Act of 2002 and assist in coordination of the audit performed by our external auditors, Deloitte. Additionally, I prepare Delta's federal and state income tax returns.

Q. Please describe your previous professional experience with Delta.

A. As the Accounting Systems Analyst/Coordinator, my primary responsibility was to assist in the integration of the accounting and information technology departments. The majority of my responsibilities were specific projects which included: streamline of the billing process, development of system for tracking meter history, creation of a gas accounting system for the non-regulated subsidiary and the mechanics for calculating the weather normalization billing adjustment.

Q. Please describe your public accounting experience related to the utilities industry.

A. I was a senior associate with PricewaterhouseCoopers from 2003-2005. During this time I primarily worked on the financial audits for LG&E Energy and its subsidiaries (including Louisville Gas and Electric, Kentucky Utilities and Western Kentucky Energy) and the audit of internal controls for Southwest Power Pool. I was in charge of planning and managing the audit fieldwork as well as focusing on industry specific issues dealing with regulatory accounting, energy trading and ISO transactions.

Q. Please summarize the scope of your testimony.

A. I am sponsoring the filing requirements in the following table:

• Proposed Tariff	Section 10(1)(a)7	Tab 7
• Proposed Tariff Changes	Section 10(1)(a)8	Tab 8
• Statement about Customer Notice	Section 10(1)(a)9	Tab 9
• Notice of Intent	Section 10(2)	Tab 10
• Customer Notice Information	Section 10(3)	Tab 11
• Sewer Utility Notices	Section 10(4)(a)	Tab 12
• Typewritten Notices by Mail	Section 10(4)(b)	Tab 13
• Other Customer Notices	Section 10(4)(c)	Tab 14
• Publisher's Affidavit	Section 10(4)(d)	Tab 15
• Verification – Mailed Notices	Section 10(4)(e)	Tab 16

• Sample Notices Posted	Section 10(4)(f)	Tab 17
• Comply w/ 807 KAR 5:051, Section 2	Section 10(4)(g)	Tab 18
• Hearing Notice Published	Section 10(5)	Tab 19
• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Local Telephone Exchange Companies	Section 10(6)(f)	Tab 25
• Independent Auditor's Report	Section 10(6)(k)	Tab 30
• FERC and FCC Audit Reports	Section 10(6)(v)	Tab 31
• Local Telephone Exchange Companies	Section 10(6)(v)	Tab 41

Additionally, Delta has included two new rate mechanisms in the proposed tariff: the Conservation / Efficiency Program ("CEP") cost recovery mechanism and the experimental Customer Rate Stabilization ("CRS") mechanism. In my testimony I describe the mechanics of these new rate mechanisms used to determine customer billing adjustments, as well as the overall Program sponsored by Delta related to promoting customer conservation and efficiency.

Q. Do you adopt these filing requirements and make them part of your testimony?

A. Yes.

II. OVERVIEW

Q. Is Delta proposing new tariffs?

A. Yes. As noted above, Delta is proposing the CEP cost recovery mechanism and the experimental CRS mechanism, both of which are further described throughout my testimony.

Q. Are the two new tariffs aligned with the recommendations contained within The Minority Report of Advocates for Energy Efficiency and the Environment on the Energy Efficiency Task Force Convened by the Kentucky Department of Public Protection released on February 26, 2007?

A. Yes. The Task Force recommended that "Electric and natural gas utility companies can do much more to help customers reduce energy waste and lower their bills. Other states have achieved dramatic gains in energy efficiency through the use of initiatives known as Demand-Side Management (DSM) programs. Through state laws, regulations, and actions by the Public Service Commission (PSC), Kentucky can and should encourage the expansion of DSM programs covering all sectors of the economy." The CEP is a DSM program which has been designed to assist the residential customer in reducing their consumption and lowering their overall bill.

In regards to rate design, the Task Force recommended that "Traditional ratemaking formulas link a utility's financial health to the volume of electricity or gas it sells and to the construction of new power plants, thus providing a strong incentive for them to sell more energy and a disincentive to invest in cost-effective DSM programs. When a utility helps customers save large amounts of energy, the utility is punished, in effect, with lower revenues and profits. The PSC needs to ensure that the utilities' most profitable investment strategy also leads them to provide energy services to their customers in the most efficient, affordable, and reliable way. Several other states are reforming their traditional electric and gas utility rate structures to align the utilities' incentives with the best interests of the public." As designed the CEP provides incentive for the utility to promote conservation by recovering the revenue lost under the CEP. As discussed later in my testimony the CEP does not recover all lost sales due to conservation. This is where the CRS mechanism provides an additional safeguard to align the interest of the utility with that of the customer. The CRS will allow Delta to earn a reasonable return, irrespective of declines in usage, as well as additions to its utility plant.

Q. Please explain Tab 24, the effect of the proposed rates on the average bill for each customer class.

A. Tab 24 contains a comparison of average bills at present rates with average bills at proposed rates. Average bills are presented separately for the different customer classes. The percentage of increase in annual revenues to Delta will approximate 9.25%. The effect upon consumer bills will vary depending upon usage.

Q. Please explain Tab 30, Section 10(6)(k).

A. Tab 30 contains Independent Registered Public Accounting Firm's annual opinion reports which are part of the Company's Annual Report to Shareholders for the year ended June 30, 2006. The Company's Independent Registered Public Accounting Firm is Deloitte. Two opinions are issued in connection with the Annual Report to Shareholders. The first report is an unqualified opinion on the financial statements taken as a whole. The second opinion is an unqualified opinion stating that Delta's assessment of internal controls is fairly stated. Based on the opinions issued by Deloitte, there were no material weaknesses or significant deficiencies in internal control, and therefore no correspondence regarding such items.

Q. Has Delta received an audit and an audit report from the FERC or the FCC (Tab 31, Section 10(6)(l))?

A. No. Delta is not audited by the FERC or the FCC.

III. CONSERVATION AND EFFICIENCY PROGRAM

Q. Is Delta's Conservation and Efficiency Program a demand-side management program?

A. Yes. Delta's CEP is a demand-side management program, as governed by KRS 278.285. Exhibit MDW-1 contains Delta's CEP guidelines.

Q. Was Delta's CEP prepared by you or under your supervision?

A. The CEP was developed through a joint effort which included myself and resources from accounting, customer development and the Company's officers.

Q. What is the purpose of the CEP?

A. Delta's current and proposed rates tie revenue to the volume used by the customer. This rate structure is a disincentive for Delta to promote customer conservation and efficiency, as decreases in customer volume negatively impact Delta's financial results. In addition, the rates which are currently in effect do not allow for the recovery of the incremental costs associated with promoting conservation and efficiency.

The CEP, as designed, aligns Delta's interest with that of the residential rate payer, by providing a mechanism to recover the lost base revenue associated with customer conservation and efficiency, as well as the expenses associated with promoting conservation and efficiency.

Q. Briefly, how does the CEP promote conservation and efficiency?

A. Conservation and efficiency is promoted through three separate components of the CEP: rebates on high efficiency appliances, home energy audits and customer awareness. The rebates on high efficiency appliances assist the customer in paying a portion of the incremental cost for a high efficiency appliance, as compared to an appliance with standard efficiency. The appliances covered under this program include furnaces, space heaters, gas logs and water heaters, and all appliances must be rated as high efficiency. The home energy audits provide for a qualified Delta employee to visit a residential customer's home to inspect and determine, based on the individual residence, what steps can be taken to prevent heating loss and therefore decrease consumption. The audit includes thermostat settings, inspection of insulation, inspection of weather stripping, windows, doors, outlets and thermal imaging of the home to determine where heat loss is occurring. The audit provides the customers with steps they can take to reduce energy consumption. Whereas the above components target specific customers who choose to participate in the CEP, Delta will also promote conservation and efficiency to all of its customers through a series of billing inserts and publications designed to offer energy saving tips. Exhibit MDW-1, provides greater detail on the guidelines of the CEP.

Q. Why does Delta's CEP offer rebates on high efficiency appliances?

A. The decision for a customer to replace an appliance is often a major and costly decision. Although there are obvious long term savings related to installing a high efficiency appliance, more often than not a customer's choice is made by the cost in today's dollars. Thus, this incremental cost is often a deterrent for a customer to select a high efficiency appliance. The rebate assists the customer in paying for the incremental cost of high efficiency appliance.

Q. Based on the program budget, what are the forecasted benefits to the customers?

A. Depending on the portions of the Program a customer participates in, the customer can save between 30 and 212 Ccf, per year. Based on the CEP budget, in year one and year two Delta expects to save its customers approximately 40,000 and 50,000 Ccf, respectively. Over a ten year period, these first two years savings accumulate to approximately 850,000 Ccf. As the CEP continues after the first two years, Delta expects participation in the CEP to increase, thus increasing the annual savings for the customers.

Q. What are the components of the CEP mechanism?

A. The CEP Mechanism has been modeled after DSM rate mechanisms previously approved by the Commission and currently in effect. There are four main components of the CEP Mechanism.

1) CEP Cost Recovery – this allows Delta to recover all costs related to planning, administering and executing the Program. A program budget has been included in Exhibit MDW-1, which details the costs to be recovered under the mechanism.

2) CEP Lost Sales – this portion of the mechanism allows Delta to recover the lost revenue from its base rates as a result of participation in the CEP rebate and energy audit components of the program. The amount of lost sales is calculated on a cumulative basis since inception of the CEP, and will reset with Delta's next rate case.

3) CEP Incentive – Delta is provided with an incentive to administer the CEP. The incentive is based on a percentage of the present value of the expected commodity savings generated in excess of the CEP costs. The incentive is similar in nature to the

incentive earned by Louisville Gas & Electric Company and The Union Light, Heat and Power Company in their electric DSM mechanisms.

4) CEP Balancing Adjustment – a balancing adjustment will ensure that amounts under the CEP are not over/under collected from the rate payer.

The proposed tariff provided for filing requirement Section 10(1)(a)7, maintained at Tab 7, provides greater detail related to the calculations of each component.

Q. With the CEP – Lost Sales and the CEP – Incentive components of the rate mechanism, is there truly a benefit to the customer?

A. Yes. The customer will save on the commodity charges under the Gas Cost Recovery mechanism. The commodity charges on a given residential customer's bill can account for approximately 65-70% of the total bill.

Q. Does the CEP - Lost Sales component of the tariff equate to decoupling of revenues to make the company whole for customer conservation/efficiency?

A. No. As Delta has seen over the past few years, customers have proactively taken steps to conserve and more efficiently use natural gas. We expect this trend to continue. A true decoupling of the revenues would recover all lost sales related to customer conservation and efficiency, irrespective of the CEP implemented by Delta. In contrast, the CEP - Lost Sales component of the rate mechanism only recovers the lost sales related to customers who participate in either the high efficiency rebate program or the home energy audits. Therefore, the mechanism does not attempt to recover all lost sales due to conservation and efficiency efforts by customers outside of the CEP or lost sales generated by the customer awareness component of the CEP. The purpose of the CEP is to aid residential customers in conserving and more efficiently using natural gas, without detriment to Delta, but the CEP does not fully decouple revenues.

Q. For the purposes of CEP – Lost Sales and CEP-Incentive components of the rate mechanism, what is the basis for the energy savings estimates?

A. The energy savings for high efficiency forced air furnaces and water heaters are based on average Ccf savings calculated from engineering estimates:

Forced air furnaces - based on the average savings of 70% and 80% efficiency furnaces as compared to a high efficiency (90%) furnace.

Water heaters - based upon a standard efficiency holding tank water heater rated as .52EF. Depending on the high efficiency model installed, the savings are calculated based on a high efficiency holding tank, power vent or on-demand model rated at .62EF, .67EF, and .85EF, respectively.

Dual fuel furnaces – based upon the Ccf savings for forced air furnaces. However, the savings are prorated for the percent of the time the dual fuel furnace can be expected to operate using natural gas under normal weather conditions.

Gas logs – based upon a consumption survey performed for a sample of Delta's log-only customers and the average efficiency between vented and un-vented gas logs.

Gas space heating – Delta does not have historical data on its space heating customer's usage. The basis for the estimate is the survey of usage for log-only customers assuming 99% efficiency for a high-efficiency model and the average savings as compared to 70% and 80% efficient models.

Energy audits – Energy savings which result from an energy audit are dependent upon each individual home (size, insulation, caulking, etc.) and the measures taken by the home owner as a result of the audit. Delta's conservation estimate is based upon the home owner, at a minimum lowering the thermostat by one degree during the heating season, irrespective of any additional conservation steps taken.

IV. EXPERIMENTAL CUSTOMER RATE STABILIZATION

Q. Briefly describe the experimental Customer Rate Stabilization billing mechanism.

A. As described in Mr. Jennings testimony, due to decreased customer usage and increasing expenses the need for an adjustment of rates is becoming more frequent. The proposed tariff for the CRS billing mechanism, provided for fulfillment of filing requirement 10(1)(a)7, describes the mechanism in full.

For Delta to be able to earn a fair, just and reasonable return on equity, year after year, more frequent rate cases will need to be filed with the Commission. Rate cases are costly, and that cost is passed through to the customers. In addition, the taxpayers bear the burden of the Attorney General's costs. The CRS allows Delta the opportunity to earn its return on equity approved by the Commission year after year, without the costs associated with an annual rate case.

The mechanism calculates what Delta's allowed return is for a given year and compares the allowed return to the actual return earned. Any over earnings are refunded to rate payers, while any under earnings are billed to the rate payers.

Q. What safeguards are in the billing mechanism to ensure that Delta does not earn a return beyond that approved by the Commission?

A. The allowed return calculated under the CRS will be calculated in the same manner as the return allowed by the Commission in the final rate order for this case. The mechanism does provide for a dead-band of +/- 50 basis points from the allowed return on equity. If the Company's actual earnings are within this band there will be no CRS adjustment. The purpose of the dead-band is to avoid relatively small adjustments to rates if the actual return earned is within a reasonable range.

If Delta's earnings are above or below the dead-band, a CRS adjustment will be calculated to adjust Delta's earnings back to the return allowed in this case. Additionally, Delta's earnings for the fiscal year will be adjusted appropriately for adjustments made during the last rate case. Therefore, any adjustment under this mechanism will normalize Delta's earnings and ensure Delta earns only the return allowed by the Commission.

Although the mechanism will be calculated based on the overall return earned for the year-ended June 30, the rates under the mechanism do not become effective until

November 1 of the same year. To provide transparency in the rate making process, an annual filing detailing the calculation of the adjustment will be submitted to both the Commission and the Attorney General by September 15 of each year. From September 15 through the effective date of the rates, November 1, the Commission and the Attorney General will have the opportunity to examine and analyze the filing.

Q. What support will be filed in connection with the annual filing so that the Commission and the Attorney General can adequately analyze the proposed adjustment?

A. We envision the filing requirements will be determined through a collaborative process between the Commission, the Attorney General and Delta. These requirements can be agreed upon prior to the first filing that is required under the tariff. As stated previously, our goal is to provide transparency in this process.

Q. How does the mechanism prevent over recovery from the rate payers?

A. The CRS Mechanism has a true-up component which ensures that any prior year over or under collections are refunded to or collected from the rate payers.

Q. How is the adjustment allocated between customer classes for refund/collections?

A. The amount to be refunded or collected for a given year, under the CRS billing mechanism, is allocated pro-rata to each customer class based on the allocation of the revenue requirement to each customer class as determined in the most recent rate case.

Q. How will the costs incurred by the Commission and the Attorney General's office to examine and analyze the filing be recovered through the CRS mechanism?

A. As stated in the tariff, the incremental employee costs associated with the annual review performed by the Commission and the Attorney General's office, as billed to Delta by those agencies, will be reimbursed by Delta. This amount will be recorded as an operating expense on Delta's income statement and will flow through to the calculation of any adjustment required under the CRS.

Q. Mechanically, does the CRS mechanism not duplicate earnings stabilization efforts in both the Weather Normalization Adjustment ("WNA") and the proposed CEP tariffs?

A. No. WNA's purpose is to remove the uncertainty of weather patterns from a customer's bill. The CEP mechanism is meant to assist residential customers in their conservation efforts. The CEP mechanism only recovers the lost sales attributable to customers who have participated in the CEP. Neither the WNA nor the CEP mechanisms account for decreases in customer count, decreased average usage per customer or fluctuations in expense items. The sole purpose of the CRS mechanism is to allow Delta to earn a fair rate of return while keeping rates as low as possible for the customer by avoiding the costs associated with frequent rate cases.

Q. Why has Delta excluded off-system transportation customers from the CRS tariff?

A. Delta's primary objective as an LDC is to provide safe and reliable service to its distribution customers. However, to the extent which Delta has the capacity, it will transport gas for off-system customers to more fully utilize its system capabilities. As discussed in Mr. Seelye's testimony, Delta's transportation rates are based on the cost of service study. However, we recognize that gas transportation service is competitive and that the incremental revenues received by Delta for such service benefits all other customers. Increasing transportation service rates year after year would decrease Delta's ability to compete as a transporter of natural gas, and thus not fully utilize the system. By not fully utilizing the system this would decrease off-system transportation revenue and thus could increase the cost of service for the other classes of customers. The off-system transportation rates would be considered in general rate cases every five years.

Q. Does this conclude your testimony at this time?

A. Yes it does.

Customer Conservation/Efficiency Program

Delta Natural Gas Company, Inc.

Table of Contents

Program Overview

PROGRAM MISSION

It is the desire of Delta Natural Gas Company, Inc. to promote the prudent use of natural gas as one of our most valued domestic natural resources. The promotion and implementation of conservation measures by the consumer are an intricate part of our strategy and a sound national energy policy. In accordance with that policy and philosophy we are unveiling a new program to benefit our customers and bring attention to the importance of conservation.

BACKGROUND

To address recent market changes regarding higher energy prices and public conservation sentiments, Delta Natural Gas Company has established its Customer Conservation/Efficiency Program ("CEP" or "the Program") that promotes energy conservation and high efficiency equipment choices.

The Program is designed as a demand-side management program which aligns the interest of the Company with that of the customer. The Program encourages customers to conserve and efficiently use natural gas while not acting as detriment to the financial performance of the Company.

While Delta is in business to sell natural gas and make a profit from those sales, the trend of customers going off service to use alternative fuels serves as a reminder to the Company of its commitment to service and to maintain long term customers. The investment of facilities to bring gas service to a community is contingent on those customers remaining satisfied consumers for an extended period of time to properly recover the investment.

Over the last several years Delta has fielded consumer inquiries concerning possible heating equipment upgrade incentives and information related to lowering natural gas consumption through conservation and increased insulation measures. To meet the public interest and assist our customer base, Delta in turn developed and offered a home energy audit program at no cost to the customer.

Delta's Customer Development Department and the local Branch Offices have jointly performed these audits. The audits identified many home construction deficiencies and made recommendations to correct the problems as well showing the homeowner many inexpensive energy tips to make the home more energy efficient.

PROGRAM BENEFITS

When considering energy efficiency from natural resource to end use, natural gas at the wellhead has 10 BTUs and arrives at the consumer's home around 9 BTUs of energy. Whereas electricity requirements at a power plant of 10 BTUs of coal or oil through the generation process only produce 3 BTUs of electricity to the consumer. As a resource natural gas is more efficient.

Delta has designed its Program to address proactively the concerns of its residential customer base related to decreasing consumption of our limited natural resource. The Program's mission is to decrease consumption through conservation and the efficient use of natural gas.

The decrease in gas usage of many of these customers through conservation or more efficient equipment will benefit Delta by having more satisfied customers. It will benefit the general population by preserving for future use more natural gas.

CONSERVATION

The Program promotes energy conservation through a home energy audit program and energy savings awareness. The home energy audit program is targeted at residential customers and identifies the specific steps they can take in their homes to conserve natural gas. As a result of the home energy audit the participant will be given an audit report which identifies the specific areas where the customer can conserve natural gas. Additionally, conservation tips will be periodically mailed to Delta's residential customers which give them facts and tips to promote overall conservation.

EFFICIENCY

A key component of Delta's CEP Program is the transition from older antiquated gas fired equipment to newer technologies with higher efficiencies. This is an important step for many consumers to better use of natural gas.

The program allows for rebate incentives for both the installation of a high efficiency natural gas appliance in new construction and the upgrade of existing Delta customers from their existing appliances to high efficiency models. Program rebates are available for high efficiency gas furnaces, space heaters, logs and water heaters.

RATE RECOVERY

The Program has a Conservation/Efficiency Cost Recovery Component (CEPRC) which is a billing adjustment to recover all direct and indirect costs associated with the program. To align the Company's interest with the customer's, the CEPRC also recovers the demand charges associated with the lost margin on the program participants, as well as an incentive based on the commodity savings generated through the Program.

High Efficiency Heating Program

Program

Existing or new conversion customers that change their current heating system (natural gas, propane, electric) to a high efficiency forced air gas furnace, high efficiency space heater, high efficiency gas logs or high efficiency gas fireplace are eligible for rebates under the Program. New homes shall be eligible for the same program if a high efficiency model is installed. Rebate amounts are determined per heating unit.

Product Information

High efficiency gas furnaces operate without a standing pilot that burns gas continuously. This saves the customer money. Ninety percent plus efficiency gas furnaces offer the consumer optional multiple stage burners and variable speed fan packages to improve their efficient use of natural gas. It is possible that a high efficiency furnace could save up to 40% of the energy cost over older technology units.

High efficiency gas logs are designed in such a manner that all produced heat stays inside the dwelling. Vented gas logs typically provide about 20 % heat with the other 80% extracted by the chimney to the outdoors and they have substantial BTU inputs requiring more fuel. In addition to producing less heat, vented gas logs and fireplaces have a compounding effect on the other heating systems within a home as they pull interior heat out through the chimney. This in turn can cause greater fuel usage and higher energy bills. High efficiency gas logs and fireplaces basically operate at or near 99.9% efficiency giving the homeowners the best heat value for their energy needs. High efficiency gas logs are not affected by power outages and do not have the environmental pollution issues found in wood smoke or coal byproducts. As the cleanest burning of all the fossil fuels, high efficiency natural gas logs and fireplaces offer benefits to the environment and can lessen the pollution concerns of electric power generation by lowering the electric demand.

Product Requirement, Qualifications, Rebate

Equipment Type	Efficiency Level	BTU Input	Rebate Amount
Forced Air Furnace	90% or greater	30,000 or greater	$400.00
Dual Fuel	90% or greater	30,000 or greater	$300.00
Space Heater	99%	10,000 or greater	$100.00
Gas Logs	99%	18,000 or greater	$100.00
Gas Fireplace	90% or greater	18,000 or greater	$100.00

Guidelines

High efficiency gas heating equipment installation must have occurred after the program inception date of October 1, 2007. Equipment must meet the above stated qualifications and be approved by the American Gas Association or other similar organization. All equipment must be properly installed and meet the code requirements as stated by the NFPA 54 handbook and all State and local code requirements. A local Customer Service Representative from Delta is required to inspect the installation for proper operation and compliance with safety requirements.

Rebate Disbursement

Rebates will be processed after the equipment inspection by the Customer Service Representative or, in the case of new construction homes, after the initial meter set. Rebates will be sent to the service address unless otherwise indicated. In the case of homebuilders utilizing the program, all rebates will be sent to their business addresses.

High Efficiency Water Heater Program

Program

Existing or new conversion customers that change their current water heater (natural gas, propane, electric) to a high efficiency natural gas tank model, power vent or on-demand model are eligible for rebates. New homes shall be eligible for rebates if a high efficiency model is installed. Rebate amounts are determined per heating unit.

Product Information

High efficiency gas water heaters are constructed with increased insulation along the outer shell and the addition of heat retention baffles inside the flue. Most power vent gas water heaters incorporate submerged combustion chambers and their burner configurations actually heat a greater area of water. On demand water heaters have no standing pilot light and typically utilize around 25 % less fuel than those with pilot lights. Natural gas water heaters have a higher recovery rate since there is not an electric element to heat up like on the electric models. Gas water heaters typically have a longer life due to the simplistic nature of a gas burner and over time will not lose their efficiency as tends to happen with electric heating elements. Conventionally vented or direct vent gas water heaters are not affected by power outages. Gas water heaters will lessen summer electric load and, therefore, decrease peak electric demand issues on the hottest of summer days. As the cleanest burning of all the fossil fuels natural gas fired water heaters offer benefits to the environment and can lessen the pollution concerns of electric power generation by lowering the load requirements.

Product Requirement, Qualifications, Rebate

Equipment Type	Efficiency Level	Unit Requirement	Rebate Amount
High Efficiency Tank Model	0.62 Energy Factor	40 gallon or greater	$200.00
Power Vent Model	0.62 energy Factor	40 gallon or greater	$250.00
On Demand Model	99%		$300.00

Guidelines

Water heater installation must have occurred after the program implementation date of October 1, 2007. Equipment must meet the above stated qualifications and be approved by the American Gas Association or other similar organization. All equipment must be properly installed and meet the code requirements as stated by the NFPA 54 handbook and all State and local code requirements. A local Customer Service Representative from

Delta is required to inspect the installation for proper operation and compliance with safety requirements.

Rebate Disbursement

Rebates will be processed after the equipment inspection by the Customer Service Representative or, in the case of new construction homes, after the initial meter set. Rebates will be sent to the service address unless otherwise indicated. In the case of homebuilders utilizing the program, all rebates will be sent to their business addresses.

Home Energy Audit Program

Program

Delta will offer a free energy audit to residential customers within its service area. The program will include an information packet and home energy conservation kit.

Audit Information

The audit will encompass a thorough analysis of the dwellings usage history and the detection of any abnormalities or trends relative to the square footage, load and surrounding dwelling usage trends. The audit will check for proper changes of the heating system filtering devices and clearance from obstructions of all return air registers. Outer wall switch plates and outlets will be inspected for insulation protection or gasket installation. Ceiling insulation levels will be observed and recommendations made as to suggested levels for the Kentucky climate zone. When visible and accessible, the home duct system will be inspected for proper insulation and seals to prevent air leakage and heat loss. All exterior windows and doors will be checked for unwanted leakage and improper sealing to cut down on energy losses. A thermal imaging camera will be utilized to show the consumer the area of greatest heat loss on the dwelling. Options and recommendations will be discussed with the occupant over conservation settings and the use of a programmable thermostat. The customer will be provided information regarding energy conservation and a written report of the energy audit with suggestions to improve the individual dwelling. An energy audit kit consisting of caulk, switch plate and outlet gaskets, electric outlet plugs and weather stripping will be provided at no cost to each consumer whom has the audit performed.

Areas Not Covered Under Energy Audit Program

Delta will not inspect the heating equipment, make adjustments or alter any settings as part of this energy audit process. All equipment issues are the responsibility of the home or business owner and recommendations will be made to contact a licensed HVAC professional for equipment tune ups or general maintenance. Any corrections to the duct system or insulation levels are the responsibility of the home or business owner. Further consultations with those contractors involved in supplying that material or actually installing insulation will be the responsibility of the home or business owner.

Guidelines

The homeowner or business owner must be present during the audit. Delta personnel will not enter a furnished dwelling without the owner or a representative present. Safety concerns or potential deficiencies will be noted and communicated to the home or business owner to the best of the energy auditor's ability. Those safety violations so noted involving natural gas will be reported to the local distribution office and a qualified Customer Service Representative will be asked to inspect the possible safety concern. The energy audit is not a safety inspection nor does it serve as an acknowledgement that the building is up to Kentucky Building code or safety standards. Delta will in no way be responsible or obligated to find or locate any violation of Kentucky Building Codes or safety violations. The energy audit is in no way a building inspection with regards to insect inspection, structural stability or safety /code regulations. Delta does not warrant or make guaranteed projections as to the actual savings from implementing the findings of the provided energy audit. The free materials in the Delta Energy Audit Kit will be provided to a responsible adult at each location and any liability issues involving those materials are the responsibility of the home or business owner. Product safety, liability and installation issues are not the responsibility of Delta. Delta does not assume any liability for the misuse of these products. The party receiving the energy audit does have the opportunity and right to refuse these materials.

Audit Cost and Scheduling

The energy audit is a service provided at no cost to any Delta customer classified as residential or small commercial. Delta's customers should call in advance for scheduling and Delta will try to make the appointments during the heating season to better assist in finding cold air infiltration and potential energy loss. Delta only provides this service between normal business hours: Monday through Friday 8:00 a.m. – 4:30 p.m. The energy audit usually takes 45 minutes to 1 hour to complete and, therefore, Delta does not schedule audits after 3:30 p.m.

Program Budget

Budgeted Program Participation

Demand Side Management Projected Budget 2008 -2016

High Efficiency Heating	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	DSM Rebates
H. Eff. Forced Air Furnaces	160	208	224	224	240	240	256	256	274	286	$400
H. Eff. Dual Fuel Units	20	26	28	28	30	30	32	32	34	36	$300
H. Eff. Gas Space Heating	20	26	28	28	30	30	32	32	34	36	$100
H. Eff. Gas Logs/Fireplaces	340	340	360	380	400	400	400	420	428	432	$100
Total H. Eff. Heating Units	**540**	**600**	**640**	**660**	**700**	**700**	**720**	**740**	**770**	**790**	
H. Eff. Water Heaters											
H. Eff. Holding Tank Models	63	72	81	81	90	90	99	99	107	111	$200
H. Eff. Power Vent Models	6	7	8	8	9	9	10	10	11	11	$250
H. Eff. On-Demand Models	1	1	1	1	1	1	1	1	1	1	$300
Total H. Eff. W. Heaters	**70**	**80**	**90**	**90**	**100**	**100**	**110**	**110**	**119**	**123**	
											Audit Cost
Energy Audits											
Residential Energy Audits	46	70	85	95	105	110	120	130	134	140	$20
Total Energy Audits	**46**	**70**	**85**	**95**	**105**	**110**	**120**	**130**	**134**	**140**	

Budgeted Expenditures

DSM Budget/ Year										
H. Eff. Forced Air Furnace	$64,000	$83,200	$89,600	$89,600	$96,000	$96,000	$102,400	$102,400	$109,600	$114,400
H. Eff. Dual Fuel Units	$6,000	$7,800	$8,400	$8,400	$9,000	$9,000	$9,600	$9,600	$10,200	$10,800
H. Eff. Gas Space Heating	$2,000	$2,600	$2,800	$2,800	$3,000	$3,000	$3,200	$3,200	$3,400	$3,600
H. Eff. Gas Log/Fireplaces	$34,000	$34,000	$36,000	$38,000	$40,000	$40,000	$40,000	$42,000	$42,800	$43,200
H. Eff. Holding Tank Modela	$12,600	$14,400	$16,200	$16,200	$18,000	$18,000	$19,800	$19,800	$21,400	$22,200
H. Eff. Power Vent Models	$1,500	$1,750	$2,000	$2,000	$2,250	$2,250	$2,500	$2,500	$2,750	$2,750
H. Eff. On-Demand Models	$300	$300	$300	$300	$300	$300	$300	$300	$300	$300
Residential Energy Audits	$920	$1,400	$1,700	$1,900	$2,100	$2,200	$2,400	$2,600	$2,680	$2,800
Program Advertising	$25,000	$20,000	$10,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
Infrared Thermal Camera	$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0
Labor	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
Office Expenses	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
Total Expenses	$167,120	$176,250	$177,800	$176,000	$187,450	$187,550	$197,000	$199,200	$209,930	$216,850

Conservation Estimates

Equipment Conservation Summary

	% Efficiency			% Efficiency			
A. High Efficiency Heating Savings	**80%**	**90%**	**Ccf Conserved**	**70%**	**90%**	**Ccf Conserved**	**Program Conservation**
1. High Efficiency Forced Air Furnaces	547.92	487.04	**60.88**	626.20	487.04	**139.15**	**100.02**
2. High Efficiency Dual Fuel Units							**20.85**
	80%	**99.00%**		**70%**	**99.00%**		
3. High Efficiency Gas Space Heating	61.98	50.08	**11.90**	70.83	50.08	**20.75**	**16.33**
	47%	**99.00%**					
4. High Efficiency Gas Logs/Fireplaces	105.4	50	**55.40**				**55.40**
B. High Efficiency Water Heating Savings	**.52 EF**	**.62 EF**					
1. High Efficiency Holding Tank Models	279.71	234.60	**45.11**				**45.11**
	.52 EF	**.67 EF**					
2. High Efficiency Power Vent Models	279.71	217.09	**62.62**				**62.62**
	.52 EF	**.85 EF**					
3. High Efficiency On-Demand Models	279.71	171.12	**108.59**				**108.59**
C. Energy Audits							
1. Residential Energy Audits			**30.00**				**30.00**

Cost Recovery

Delta will recover its costs associated with the program through the Conservation/Efficiency Program Cost Recovery Mechanism (CEPRC) which is a tariff applicable to all residential customers. The tariff can be broken down into the following four specific components:

- Conservation/Efficiency Cost Recovery (CEPCR)
- CEP Revenue from Lost Sales (CEPLS)
- CEP Incentive (CEPI)
- CEP Balance Adjustment (CEPBA)

CEPCR

Under the tariff, the CEPCR shall include all actual costs, direct and indirect, under this program which have been approved by the Commission. This includes all direct costs associated with the program including rebates paid under the program, the cost of energy audit supplies, and customer awareness related to conservation/efficiency. In addition, indirect costs shall include the costs of planning, developing, implementing, monitoring, and evaluating CEP programs. In addition, all costs incurred by or on behalf of the program, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the CEPCR.

CEPLS

To effectively promote and execute the program, the Company shall recover the annual lost sales attributable to customer conservation/efficiency created as a result of the Program. This aligns the Company's interest with the customers' by reducing the correlation between volume and revenue for those customers who elect to participate in the program. The lost sales are the estimated conservation, per participant, times the base rate for the applicable customer. The goal is to make the Company whole for promoting the program. Lost sales are based on the cumulative lost sales since the program inception and will reset when the Company completes a general rate case.

CEPI

As a result of the program, the customers who participate in the program will save on their gas bills due to decreased usage, which results in decreased commodity charges. As an incentive for the Company to devote the necessary monetary and physical resources to promote and administer the program, the Company will earn a fifteen percent (15%) incentive based on the net resource savings of the Program participants.

Net resource savings are defined as Program benefits less utility Program costs and participant costs where Program benefits will be calculated on the basis of the present value of Delta's avoided commodity costs over the expected life of the Program. For the purpose of calculating the Program benefits, a ten year Program life is assumed with future gas costs over the ten-year period based on projection in the Department of Energy's *Annual Energy Outlook*. The present value is calculated based on Delta's discount rate used for financial reporting purposes which is based on the rates of high-quality fixed-income investment.

CEPBA

The CEPBA is a balancing adjustment to adjust the current rates for any over-(under-) collections of the previous year's CEP rates. An interest factor is applied to any over-(under-) collections based on the Average 3-Month Commercial Paper Rate for the Program year.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 20 2007
PUBLIC SERVICE
COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	**CASE NO. 2007-00089**

DIRECT TESTIMONY OF

MARTIN J. BLAKE

AFFIDAVIT

The affiant, Martin J. Blake, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, in the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

Martin J. Blake
MARTIN J. BLAKE

STATE OF KENTUCKY)
)
COUNTY OF JEFFERSON)

Subscribed and sworn to before me by Martin J. Blake, this the 13 day of April, 2007.

My Commission Expires: March 3, 2010

[signature]
Notary Public, State at Large, Kentucky

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Martin J. Blake. My business address is 6435 W. Highway 146, Suite 2, Crestwood, Kentucky 40014.

Q: BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A: I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of marketing, market research, rate and regulatory support, training, and strategic planning for energy industry clients.

<u>Professional Qualifications & Experience</u>

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A: I received my Ph.D. in Agricultural Economics in 1976 from the University of Missouri, Columbia. My doctoral work centered on the areas of marketing and econometrics. I also hold a Master of Arts in Economics from the University of Missouri, Columbia, which I received in 1972. In addition, I received a Bachelor of Arts degree in Economics from Illinois Benedictine College in 1970.

Q: HAVE YOU FILED TESTIMONY REGARDING THE APPROPRIATE RETURN ON EQUITY IN OTHER PROCEEDINGS?

A: Yes. I have filed testimony regarding the appropriate return on equity in Federal Energy Regulatory Commission Docket No. ER01-1938 in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony. I have filed testimony regarding the appropriate return on equity in Federal Energy Regulatory Commission Docket No. ER02-708 in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony. I have filed testimony regarding the appropriate return on equity in Docket Nos. 99-046 and 04-00067before the Kentucky Public Service Commission regarding the return on equity in support of Delta Natural Gas Company's requests for adjustments in rates.

Q: PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO JOINING THE PRIME GROUP.

A: I have professional experience as an economist and professor of economics, as a utility regulator, and as a utility manager and executive.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS AN ECONOMIST.

A: From January 1977 to December 1986, I was employed first as an Assistant Professor, then as an Associate Professor, and finally as a Professor of Agricultural Economics at New Mexico State University in Las Cruces, New Mexico ("NMSU"). I was the head of the undergraduate program and taught economics, agricultural economics and econometrics. While at NMSU, I also worked as a consultant for various clients, providing price forecasting, load forecasting, and marketing services. Since 1992, I have taught mathematical economics and econometrics as an Adjunct Professor in the Economics Department at the University of Louisville. Prior to my joining the faculty at NMSU, I served in the U. S. Army as an instructor of economics, statistics, and accounting at the U. S. Army Institute of Administration at Fort Benjamin Harrison, Indianapolis, Indiana.

I also have a wealth of experience with the application of economics to utility public policy issues. In addition to my experience as a utility regulator and executive, which I describe below, I have taught ratemaking for utilities at the NARUC Annual Regulatory Studies Program at Michigan State University since 1993. From May 1983 to August

1983, while on a sabbatical leave from NMSU, I served as a Policy Analyst for the Assistant Secretary for Land and Water at the U. S. Department of Interior.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY REGULATOR.

A: From January 1987 to November 1990, I served as a Commissioner and as the Chairman of the New Mexico Public Service Commission. As a Commissioner, my duties included making policy and adjudicatory decisions regarding rates, terms of service, financing, certificates of public convenience and necessity, and complaints for electric, gas, water, and sewer utilities. As Chairman, I supervised a staff of thirty-two professionals and sixteen support staff. During my tenure on the New Mexico Commission, I also served as Chairman of the Western Conference of Public Service Commissioners Electric Committee and as Chairman of the Committee on Regional Electric Power Cooperation, a group composed of state public service commissioners and representatives from the state energy offices of the thirteen western states.

As a Commissioner, I interpreted legislation, reviewed prior Commission cases to determine the precedents that they provided, drafted rules and regulations, wrote Orders, conducted hearings, ruled on motions, and served as an arbitrator in alternative dispute resolution proceedings. I performed adjudicatory and regulatory functions for the four years that I served on the Commission.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY MANAGER.

A: From December, 1990 to June 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). Initially, I served as LG&E's Director of Regulatory Planning. In this position, I was responsible for coordinating all of LG&E's state and federal regulatory efforts, and prepared and presented testimony to regulators. My areas of responsibility were expanded in April 1994 to include marketing and strategic planning.

As the Director, Marketing, Planning and Regulatory Affairs, I was responsible for coordinating LG&E's retail gas and electric marketing, strategic planning, and state and federal regulatory efforts. I continued to be employed in that capacity at LG&E until June 1996, when I joined the Prime Group as one of its Principals.

Q: PLEASE DESCRIBE THE INDUSTRY GROUPS IN WHICH YOU HAVE PARTICIPATED.

A: I have served on several regional transmission coordination groups such as the Interregional Transmission Coordination Forum, and the General Agreement on Parallel Paths, as well as the following committees of the Edison Electric Institute ("EEI") -- Economics and Public Policy Executive Advisory Committee, Strategic Planning Executive Advisory Committee, Transmission Task Force, and Power Supply Policy Technical Task Force. Currently, I am a member of the Midwest ISO Transmission Owners Committee and the Transmission Owners Tariff Working Group representing Southern Illinois Power Cooperative and Hoosier Energy. I serve as the Vice-Chairman of the Transmission Owners Tariff Working Group.

Q: HAVE YOU TAUGHT ANY COURSES OR SEMINARS IN THE AREA OF UTILITY RESTRUCTURING?

A: Yes. In addition to teaching ratemaking for electric utilities at the NARUC Annual Regulatory Studies Program since 1993, I have also taught a course regarding the institutions and organizations of the new electric utility industry. Each year, I also teach and conduct numerous workshops and programs, and deliver invited presentations to utility managers and regulators on a variety of subjects including ratemaking, marketing, utility finance, and industry restructuring.

Q. IN WHICH CASES HAVE YOU PREVIOUSLY TESTIFIED?

A. A list of the cases in which I have previously testified is included in Exhibit MJB-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Delta Natural Gas Company, Inc. ("Delta") engaged The Prime Group to conduct an analysis of and to provide a recommendation regarding the appropriate cost of common equity for use in determining Delta's weighted cost of capital in this proceeding. My testimony contains the results of this analysis and identifies the fair rate of return on equity that Delta should be given the opportunity to earn during the period when the new rates will be in effect. My analysis utilizes appropriate financial valuation techniques and incorporates the factors that affect the return on equity that shareholders expect when investing in Delta and in other companies of corresponding risk. My testimony also addresses the reasons for allowing Delta to implement and recover the costs and an appropriate incentive for its Consumer Conservation and Efficiency ("CEP") program and the reasons for allowing Delta to implement an experimental Customer Rate Stabilization ("CRS") program.

Return on Equity

Q. PLEASE DESCRIBE DELTA'S BUSINESS OPERATIONS.

A. Delta purchases, produces and stores gas for distribution to retail customers, and also provides transportation service to industrial customers and interconnected pipelines through facilities located in 23 counties in central and southeastern Kentucky. The company had about 37,330 retail customers at the end of 2006. Its service territory is more rural than most publicly traded, investor owned natural gas distribution companies and consists mainly of light industry, farming and coal mining operations. More than 86% of Delta's customers are residential.

Exhibit MJB-2 shows Delta's total capitalization compared to other publicly traded, investor owned natural gas distribution utilities. The data in Exhibit MJB-2 was taken from a report titled Natural Gas Industry Summary Quarterly Financial & Common Stock Information issued by Edward Jones Co. December 31, 2006. This report classifies companies that provide natural gas into three categories: 1) diversified companies, 2) combination gas and electric companies and 3) natural gas distribution companies. Delta is classified as a natural gas distribution company. Among the publicly traded, investor owned natural gas distribution utilities included in this report Delta was the third lowest with respect to total capitalization.

It is important to note that the earned return on shareholder equity for Energy West, which has the lowest capitalization of all of the natural gas distribution companies in the panel, has been over 13% for the past 4 years and has averaged over 13% over the past eight years according to the September 15, 2006 Value Line. The two natural gas distribution utilities in Exhibit MJB-2 with a lower total capitalization than Delta had percentages of equity of 57% and 52%, which are higher than Delta's 47% equity. These equity percentages are calculated using long term debt and equity and do not include short term debt in the calculation of the equity percentage for a company. Thus, the percent equity in the Edward Jones report is different than the percentage of equity in the capital structure for Delta in this proceeding. However, because it uses the same calculation for all companies in the panel, the Edward Jones report does provide a good basis for comparing the companies in the panel with regard to the equity component of their capitalizations. Thus, Delta can be characterized as a small, publicly traded, investor owned, natural gas distribution utility with an essentially rural service territory and with a relatively highly leveraged capital structure relative to other natural gas distribution utilities of similar size.

Q. IS THERE A PUBLIC BENEFIT TO PROVIDING NATURAL GAS SERVICE TO RURAL AREAS?

A. Yes. If natural gas service is available in an area, customers have a choice whether to use natural gas or electricity for particular applications. Customers' ability to switch between natural gas and electricity helps to keep downward pressure on the prices of both products. Furthermore, the availability of natural gas service can help in attracting industrial loads to an area and thus assist in economic development efforts. However, if natural gas service is to be provided to rural areas, the companies providing such service must have the opportunity to earn adequate returns or they will no longer be able or willing to provide such service. Additionally, in order to expand Delta's service into additional rural areas, either through main extensions or through acquisition of distressed natural gas companies, Delta needs a sufficiently high return on equity to increase the percentage of equity in its capital structure to a level more appropriate for a company of its size, decrease its payout ratio which is above the industry average, and increase its interest coverage which is below the industry average. None of this can be done with a return on equity that is inadequate.

Q. WHAT ARE THE TRENDS IN THE NATURAL GAS DISTRIBUTION INDUSTRY AT THE PRESENT TIME?

A. Recently, Value Line issued an industry report for the Natural Gas Distribution industry in which Delta is included (Exhibit MJB-3). This report stated that:

> The earnings performance for many Natural Gas (Distribution) companies has been hurt by warmer-than-normal temperatures and conservation by customers. To offset the losses, many companies have recently been applying for regulatory policies that protect against both of these issues. Moreover, it should be noted that the key features of owning a utility stock are their Safety and better-than-average dividend yields, rather than price performance or appreciation potential. However, with interest rates at higher levels compared to the past few years, some of the positive attributes of owning these stocks may be reduced. (The Value Line Investment Survey September 15, 2006, p. 459).

This shows that Delta is not alone in pursuing the mechanisms that it is seeking in this filing to stabilize its returns. Additionally, it should be noted that Value Line forecasts a return on shareholder equity for the Natural Gas Distribution industry as a whole of 12% for the period 2009 through 2011. A return on equity of 12% is forecast even though it is noted that many natural gas distribution companies either have or are seeking mechanisms to stabilize their returns. This helps to provide a context for the return on equity that Delta is seeking in this proceeding.

Q. HOW SHOULD THE RATE OF RETURN BE DETERMINED UNDER PUBLIC UTILITY REGULATION?

A. The purpose of public utility regulation with respect to rate of return is to permit a utility to earn its cost of capital while avoiding monopoly profits. Long-run earnings above the cost of capital would imply monopoly profits, while long-run earnings below the cost of capital would impair a utility's ability to attract capital on reasonable terms. A rate of return based on a utility's cost of capital is consistent with the guidelines established by the U.S. Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944). These cases require that a utility be allowed to earn a rate of return that: 1) is comparable to alternative investment opportunities of corresponding risk, 2) will permit capital attraction on reasonable terms, and 3) will maintain a utility's financial integrity.

In the Hope case, the U.S. Supreme Court stated that:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (emphasis added) [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

It is important to note that the U.S. Supreme Court did not limit the return on equity to being commensurate with other utilities. It stated that the return on equity should be commensurate with other companies having corresponding risk. This is important because there are not many investor owned utilities as small as Delta. However, there are a number of companies that are comparable to Delta with similar size and with similar risk profiles as measured by calculated beta coefficients in other industries.

Q. HOW DO YOU INTERPRET THE REQUIREMENT THAT A UTILITY HAVE AN OPPORTUNITY TO EARN A FAIR RATE OF RETURN?

A. An opportunity to earn a fair rate of return implies that a utility has a reasonable assurance that it will be allowed to earn a rate of return that is sufficient to attract capital, that will maintain its financial integrity and that is comparable to the return earned by alternative investments of comparable risk. While there are numerous factors that may result in an actual rate of return that is higher or lower than the allowed rate of return in any given year, a utility that consistently earns less than the allowed rate of return or which has averaged significantly less than the allowed rate of return for a long period of time cannot be said to have a reasonable assurance of earning the allowed rate of return. Thus, an assurance of earning a fair and reasonable rate of return could be viewed statistically as the arithmetic average of a series of returns over a period of time equaling the allowed rate of return. The problem with this approach is that, if there is significant variability in the returns, several years of earning below the allowed rate of return could cause severe financial harm to a utility while waiting for the years of above average returns to materialize. Thus, it may make sense for regulators to not only deal with the mean value of the distribution of returns, as they do when they set the allowed rate of return in a rate case, but to also deal with the variability of the returns through a mechanism such as the CRS mechanism that I will address later in my testimony.

Q. WOULD YOU REGARD DELTA'S CURRENT RATES AS PROVIDING AN OPPORTUNITY TO EARN AN ADEQUATE RETURN FOR PROVIDING NATURAL GAS SERVICE TO RURAL AREAS?

A. No, I would not. In December, 1997, the Commission issued an Order in Case No. 97-066 which set new rates for Delta which became effective in January, 1998. In this case, the Commission allowed a return on common equity of 11.6%. In December, 1999, the Commission issued an Order in Case No. 99-046 which set new rates for Delta which became effective in January, 2000. In this case, the Commission also allowed a return on common equity of 11.6%. In November, 2004, the Commission issued an Order in Case No. 2004-00067 which set new rates for Delta which became effective on October 7, 2004. In this case, the Commission allowed a return on common equity of 10.5%. However, Exhibit MJB-4 shows that since 1995, Delta has never earned an actual return on shareholders equity that was as high as the 11.6% ROE allowed by the Commission in Case Nos. 97-066 and 99-046. For the last twelve years, Delta has averaged a 9.13% return on shareholder equity with the return on equity in any single year never equaling or exceeding 11.3%. This is especially distressing in the years immediately following these three rate cases that were the first years that the new rates went into effect. In 1998, the first year that new rates were in effect pursuant to Case No. 97-066, Delta actually earned a return on shareholder equity of 8.2% which is 340 basis points below the Commission allowed ROE of 11.6%. In 2000, the first year that new rates were in effect pursuant to Case No. 99-046, Delta actually earned a return on shareholder equity of 11.1% which is 50 basis points below the Commission allowed ROE of 11.6%. In 2005, the first year full year that new rates were in effect pursuant to Case No. 2004-00067, Delta actually earned a return on shareholder equity of 9.8% which is 70 basis points below the Commission allowed ROE of 10.5%. If there was ever a time when it could be expected that a utility would earn its allowed rate of return, it would be the first year that new rates went into effect. When Delta has not earned a return on shareholder equity as high as the allowed rate of return in any of the last twelve years, even though it has been in three times during that period of time for rate cases, it cannot be said to have a reasonable assurance of earning the allowed rate of return. Delta's actual annual earned returns on equity should have the same mean as the allowed rate of return with actual annual earned returns both above and below the allowed rate of return. This has not been the case for the last twelve years, and it indicates a problem that the Commission could remedy by allowing Delta to implement the experimental CRS mechanism that it is proposing in this proceeding.

Q. WHAT FACTORS DO YOU BELIEVE HAVE CAUSED DELTA TO UNDER EARN COMPARED TO ITS ALLOWED RATE OF RETURN ON EQUITY?

A. I believe that there are several factors: 1) Delta's equity as a percentage of total capitalization is lower than other natural gas distribution companies of similar size, 2) Delta's predominantly rural service territory, 3) customer conservation in response to higher natural gas prices, and 4) efficiency gains of natural gas appliances. Customer conservation in response to higher prices and efficiency gains of natural gas appliances result in under recovery of Delta's fixed costs and margin when any portion of fixed cost and margin are collected through a volumetric charge rather than through a fixed charge per customer per month. With a portion of Delta's fixed costs and margins currently collected using a volumetric charge, both customer conservation and appliance efficiency gains have lead to under recovery as these factors have reduced the per customer usage of natural gas.

Q. PLEASE DESCRIBE DELTA'S EQUITY AS A PERCENTAGE OF TOTAL CAPITALIZATION COMPARED TO OTHER NATURAL GAS DISTRIBUTION COMPANIES.

A. As described above, Exhibits MJB-2 and MJB-3 provide data for natural gas distribution companies ranked by total capitalization and percentage equity, respectively taken from <u>Natural Gas Industry Summary Monthly Financial & Common Stock Information</u> published by Edward Jones. The mean percentage of equity is calculated as 51% for the panel of fifteen natural gas distribution utilities with a median of 52%. These percentages are calculated using long term debt and equity and do not include short term debt in the calculation of the equity percentage for a company. Thus, the percent equity in the Edward Jones report is different than the percentage of equity in the capital structure for Delta in this proceeding. However, because it uses the same calculation for all companies in the panel, it does provide a good basis for comparing the companies in the panel with regard to the equity component of their capitalizations. The percentage of equity for the two companies smaller than Delta are 57% and 52%. The percentage of equity for the company that is the next largest is 59%. Delta's reported percentage of equity of 47% is 4% below the mean and 5% below the median for this panel. It is also below natural gas distribution companies of similar size which makes Delta more heavily leveraged than other natural gas distribution utilities of similar size.

Q. DOES A LOWER PERCENTAGE OF EQUITY RELATIVE TO TOTAL CAPITALIZATION MAKE DELTA A RISKIER INVESTMENT?

A. Yes. The more debt that a firm has as a part of its total capitalization, the greater are the fixed interest payments that the firm will have to make to bond holders out of any given revenue stream that it generates. A company is required to make payments to the bond holders in specified amounts at specified times, while it is under no such obligation to its common equity holders. Thus, the more equity the firm has, the greater is its ability to weather revenue fluctuations. However, this flexibility comes at a cost, as equity is more expensive than debt because of the greater risk that shareholders bear. As a company's business environment becomes riskier and its business risk becomes greater, the company should increase its equity and lower its debt ratio. By reducing its debt ratio, its fixed obligations to bond holders would be reduced and the company would be better able to manage the financial fluctuations that result from a riskier business environment. Furthermore, a utility's equity ratio must be high enough to allow additional debt capital to be issued without an adverse effect on its credit rating. This would be consistent with the criteria established in the Bluefield and Hope cases that the rate of return be sufficient to permit capital attraction on reasonable terms. If the capital structure does not permit some margin for additional debt financing at all times, a utility is subject to the potential adverse impact of unanticipated tight credit conditions, thus making it a riskier investment. Delta has increased the percent of equity in its overall capitalization since its last rate case, but it is still below the average percentage equity for both the panel of fifteen natural gas distribution companies and below the average percentage equity for natural gas distribution companies of similar size as Delta. Getting Delta's percentage of equity closer to the average for natural gas distribution companies of a similar size will only occur if the Commission allows a high enough rate of return to accommodate this long term improvement in Delta's equity ratio.

Q. HOW WOULD DELTA'S LOW EQUITY RATIO AFFECT THE RETURN ON EQUITY THAT IT EARNS?

A. Because Delta is about 60% debt financed based on the capital structure in this proceeding, its fixed obligations to bondholders are high, thus exacerbating the impact on the return on equity resulting from any revenue reductions that Delta might experience. This is an important factor that contributes to the fact that Delta has not earned its allowed rate of return in any of the past twelve years.

Q. COULD YOU GIVE AN EXAMPLE OF HOW LEVERAGE MIGHT AFFECT THE ACTUAL RETURN ON EQUITY EARNED BY DELTA?

A. Yes. Exhibit MJB-5 provides several examples of how a change in the percentage of equity in Delta's overall capitalization would affect the actual return on equity earned by Delta. All three examples in Exhibit MJB-5 have the same total capitalization, but have different equity ratios. The first example in Exhibit MJB-5, uses the same percentage of equity and debt as Delta's capital structure in this proceeding and assumes a return on equity of 12.5% and an interest rate of 7% on the debt. The dollar value of the return elements for equity and debt are calculated by multiplying the dollar value of the equity and debt capitalization by their respective rates of return and interest. In Example 1, the dollar value of the return element for equity would be $6,514,444 and the dollar value of the return element for debt would be $5,391,144. Next assume that Delta experiences a decrease in earnings of $2,000,000. Delta would still have to pay $5,391,144 to debt holders and now would have only $4,514,444 to provide to shareholders. Dividing $4,514,444 by the $52,115,554 of equity capitalization would result in an actual return on equity of 8.66%.

Example 2 uses a capital structure that reflects the industry average as calculated in Exhibit MJB-2 and uses the same rates of return and interest as in Example 1. Thus, the only factor that is changing is the equity and debt ratios. Again a decrease in earnings of $2,000,000 is assumed. Delta would still have to pay $4,429,224 to debt holders and now would have only $6,232,159 to provide to shareholders. Dividing $6,232,159 by the $65,857,269 of equity capitalization would result in an actual return on equity of 9.46%. In both Examples 1 and 2, the $2,000,000 decrease in earnings is a result of operations and is not influenced by the capital structure used to finance the company. However, this same $2,000,000 decrease in earnings has a very different impact on the actual return on equity depending on the debt leverage of the company.

A comparison of Examples 1 and 2 also illustrates another important point. In Example 2, the return element included in the revenue requirement would be $12,661,383, while in Example 1 the return element included in the revenue requirement would be $11,905,588, which is $755,795 lower. Thus, with a lower percentage equity ratio than the industry as a whole, Delta's customers pay lower rates while Delta experiences a significant adverse effect on its ability to earn its allowed rate of return if it experiences any earnings shortfalls. This is simply not an equitable result.

Example 3 simply repeats the above example for a capital structure consisting solely of equity. In Example 3, the $2,000,000 decrease in earnings would result in an actual return on equity of 10.95%.

These three examples illustrate that Delta's equity ratio, which is below both the industry average and the average for natural gas distribution companies of similar size, has a significant adverse effect on its ability to earn its allowed rate of return. Any given earnings shortfall for Delta will result in a lower actual return on equity than for the average natural gas distribution company. These examples help in understanding why Delta has not earned its allowed rate of return in any of the past twelve years. This significant adverse impact on Delta's ability to earn its allowed rate of return must be considered by the Commission in setting an appropriate rate of return for Delta.

Q. HOW WOULD DELTA'S PREDOMINANTLY RURAL SERVICE TERRITORY AFFECT THE RETURN ON EQUITY THAT IT EARNS?

A. Delta serves an area in eastern Kentucky that is predominantly rural with low population density. This low population density results in higher fixed cost per customer for serving rural areas compared to the fixed cost per customer incurred in an urban area. This higher fixed cost per customer results from both a higher cost of installing the pipe needed to serve a customer and the higher cost of maintaining the lines. Furthermore, these rural customers tend to have a lower annual usage and a larger proportion of temperature sensitive load than urban customers. This relatively high fixed cost to serve small highly temperature sensitive loads translates to a higher fixed cost burden for Delta and a more variable revenue stream. The higher fixed costs resulting from operations compounds the problem of high fixed obligations to bond holders resulting from a low equity ratio, and exacerbates the impact on the return on equity resulting from any revenue reductions that Delta might experience, as demonstrated above. Thus, the low population density in rural areas that results in a higher fixed cost burden for Delta with more variability in the return stream due to the large amount of temperature sensitive load for these rural customers would justify a higher allowed rate of return for Delta. It would be very difficult, if not impossible, to quantify the separate impact on return on equity resulting from the rural character of Delta's service territory. However, this factor combined with a lower than average equity ratio for Delta, would justify a higher than average rate of return on equity for Delta.

Q. HOW WOULD YOU ASSESS THE BUSINESS ENVIRONMENT WITHIN WHICH DELTA OPERATES?

A. Delta provides natural gas service in a service territory that substantially overlaps the electric service territory of Kentucky Utilities Company, which has some of the lowest electric rates in the nation. This direct competition with a low cost electric utility increases Delta's business risk. Additionally, Delta is a small company with a capitalization that would fall in the smallest micro-cap stock range as defined in the Risk Premia Over Time Report: 2006 published by Ibbotson Associates (Exhibit MJB-6), which includes companies with market capitalizations at or below $169,195,000. Small companies are generally regarded as riskier than larger companies and have correspondingly higher rates of return. Fama and French reported that:

> If assets are priced rationally, our results suggest that stock risks are multidimensional. One dimension of risk is proxied by size, ME. Another dimension of risk is proxied by BE/ME, the ratio of the book value of common equity to its market value. (Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns", The Journal of Finance, Vol. 47, June, 1992, p. 428.)

Fama and French went on to report that:

> The size effect (smaller stocks have higher average returns) is thus robust in the 1963-1990 returns on NYSE, AMEX, and NASDAQ stocks. In contrast to the consistent explanatory power of size, the FM [Fama-MacBeth] regressions show that market ∃ does not help explain average stock returns for 1963-1990. (Fama and French, p. 438)

Thus, this research means that small companies such as Delta are riskier than companies with larger capitalizations and a higher rate of return on equity would be appropriate for such companies. This is particularly true in Kentucky. It is simply not consistent with these research results to allow all natural gas distribution companies in Kentucky essentially the same return on equity when the other investor-owned natural gas companies in Kentucky are a part of corporations that are over 30 times larger than Delta. Interestingly, even Atmos, which has the largest capitalization of all fifteen companies in the Edward Jones natural gas distribution panel, only falls in the fourth decile of companies in the Ibbotson report (Exhibit 6) and should have 1.1% added to any CAPM calculations based on its size.

Additionally, natural gas commodity prices have become much more volatile since the decision issued by the Commission in Delta's last rate case. The run up of natural gas prices after hurricanes Katrina and Rita along with the recent reduction to current levels are a good indication of just how volatile natural gas prices can be.

Q. DOES THE INCREASED VOLATILITY IN NATURAL GAS PRICES AFFECT THE RETURN ON EQUITY THAT DELTA SHOULD BE ALLOWED TO EARN?

A. Yes. Exhibit MJB-7 is a table that shows United States natural gas wellhead prices and city gate prices since Delta's last rate case. This table illustrates the volatility of natural gas prices since the Order issued by the Commission in Delta's last rate case in November 2004. Delta has a Gas Cost Recovery ("GCR") mechanism that is calculated quarterly. Any under or over recoveries during a quarter are recovered over the next twelve months. Delta is not allowed to earn a return on any money that it has devoted to funding such under-recoveries. The increased price volatility since its last rate case has resulted in significant under-recoveries and deferred gas costs that Delta has had to finance with no interest. In December 2004, 2005 and 2006, Delta had deferred gas costs of about $7.5

million, \$7.4 million, and \$1.1 million, respectively. Delta has had to finance these under-recoveries with a mix of internal financing and short term borrowing. As noted above, the interest that Delta incurs in financing any under-recoveries is an expense that is not recovered by Delta through the GCR. This has helped to generate earnings shortfalls that are exacerbated by Delta's low equity ratio as demonstrated above. A higher return on equity would provide a larger pool of internal resources to finance such under-recoveries and would help to mitigate Delta's reliance on short term borrowing. This natural gas commodity price volatility is a significant risk factor when Delta has to finance these costs with no interest recovery allowed. The Commission should allow a return on equity that would help to provide Delta with the internal capital necessary to fund such under-recoveries and mitigate the necessity of using short term debt for these purposes.

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW ("DCF") METHOD FOR ESTIMATING THE APPROPRIATE RETURN ON EQUITY.

A. The DCF method for estimating an appropriate return on equity is based on the following equation, which defines the long run expected return (the appropriate return on equity) as the discount rate that equates the current stock price with the stream of expected future dividends:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \cdots$$

where,

P = the current price of the stock,

D_i = the dividend in year i, and

k = the investors' discount rate or expected rate of return.

If the growth is a constant rate, g, this equation can be expressed as the sum of an infinite geometric series:

$$k = \frac{D_1}{P} + g$$

While the DCF method is usually calculated using this formula, it can also be described in words. The terms in the DCF formula represent investors' assessment of expected future cash flows they will receive in relation to the price that they pay for a share of stock. The DCF formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is an initial cash flow in the form of a dividend. The second is the cash flow resulting from dividend growth in the future. Although investors know that negative growth and losses can occur, they expect long term positive dividend growth. Rational investors expect long term positive growth, or they would hold cash rather than invest with the expectation of a loss. The sum of the rates of these two flows, initial and future, equals the return that investors require from their investment in the stock at the current price. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF calculation determines what shareholders require from a company in terms of present and future dividends relative to the current market price of the company's stock. If the DCF model indicated a return on equity of 8% and the current stock price used to calculate this return on equity was $25, this tells us that shareholders are expecting an 8% return on equity in return for their $25 investment in the stock. i.e. an 8% return on the market equity, not on the book equity or on rate base which have little or no relation to the market equity.

Q. DOESN'T THE GROWTH RATE THAT IS ULTIMATELY SELECTED BY THE COMMISSION IN CALCULATING RETURN ON EQUITY USING THE DCF METHODOLOGY BECOME A SELF-FULFILLING PROPHECY?

A. Yes. If the Commission selects a high growth rate resulting in a higher return on equity, there will be sufficient earnings to grow dividends and increase the equity component of Delta's capital structure. If the Commission selects a low growth rate, the lower level of earnings will only allow dividends to increase slightly, if at all. Thus, looking at historic dividend growth rates is not a good indicator of investor expectations with regard to dividends. It simply reflects the return on equity that the Commission has allowed Delta in the past. And as noted above, the deck seems stacked against Delta even earning the allowed rate of return, with Delta's actual earned return being lower than the allowed rate of return in each of the past twelve years.

Q. WHAT WOULD THE DCF MODEL YIELD AS AN EXPECTED RETURN ON EQUITY FOR DELTA?

A. The results of the DCF analysis for Delta are shown in Exhibits MJB-8 and MJB-9. The high and low stock prices for the year and the most recent annual dividend for the DCF calculation were obtained from the Value Line Investment Survey - Small and Mid-Cap Edition, December 15, 2006 (Exhibit MJB-10). Even though the Value Line Investment Survey for large companies reports forecasted future dividend growth rates for companies included in this edition, the Value Line Investment Survey - Small and Mid-Cap Edition did not report a forecasted dividend growth rate for Delta. I ultimately used two growth rates in the DCF calculations for Delta. The first growth rate that I used was the sustainable growth rate calculated from the following formula:

$g = br + sv$,

where: b is the expected retention ratio;

r is the expected earned rate of return on common equity;

s is the percent of common equity expected to be issued annually as new common stock; and

v is the equity accretion rate.

The amount of common stock that Delta issues annually is minimal, so the second term of the equation for all practical purposes is zero. The calculation of the sustainable growth rate using this formula was based on data from Value Line and is shown in Exhibit MJB-8. The resulting sustainable growth rate for Delta was 2.37% and this is the growth rate used in the DCF calculations in Exhibit MJB-8.

The second growth rate that I used in the DCF calculations was the average of the dividend growth rates for the nine large companies in the Edward Jones panel that were covered by the Value Line Investment Survey. Only natural gas distribution companies with a positive dividend growth rate were used in calculating the average. As discussed above, rational investors expect a positive growth rate and including companies with a negative or zero dividend growth rates would not be representative of investor expectations. The average dividend growth rate for the nine natural gas distribution companies covered by the large company edition of Value Line was 3.67%, and this is the growth rate that was used in the DCF calculations in Exhibit MJB-9.

The high and low annual stock prices during 2006 were used in calculating a range of estimated returns in the DCF analysis. Use of the high stock price in the DCF analysis with a sustainable growth rate of 2.37% resulted in an estimated ROE of 6.84%, and use of the low stock price in the DCF analysis resulted in an estimated ROE of 7.35%. Use of the high stock price in the DCF analysis with an average growth rate of 3.67% resulted in an estimated ROE of 8.14%, and use of the low stock price in the DCF analysis resulted in an estimated ROE of 8.65%.

Q. CAN THESE CALCULATED RETURNS ON EQUITY USING THE DCF MODEL BE APPLIED TO BOOK VALUE CAPITALIZATION?

A. No. The DCF calculations in Exhibits MJB-8 and MJB-9 that resulted in the estimates of 6.84%, 7.35%, 8.14% and 8.65% for return on equity were made using the current stock price, and so these returns on equity are meaningful only when applied to market capitalization. As explained above, if the DCF model indicated a return on equity of 8% and the current stock price used to calculate this return on equity was $25, this tells us that shareholders are expecting an 8% return on equity in return for their $25 investment in the stock. They are not expecting an 8% return on the book value capitalization of the company, which has little or no relationship o the market value of the stock. If the returns on equity calculated using the DCF formula are to be applied to the book value of equity, further calculations are necessary.

In Exhibit MJB-8, the estimated returns on equity calculated using the high and low stock prices are multiplied by the market capitalization calculated at the high and low stock prices to obtain the actual dollars that shareholders expect to receive annually from their investment. The market capitalization was calculated by multiplying the high and low stock price by the number of outstanding shares of stock, which for Delta was 3,261,034 shares. To convert this to a return on equity that could be applied to book capitalization, it is necessary to divide the actual dollars that shareholders expect to receive annually from their investment by Delta's book value of equity. These calculations resulted in returns on equity that could be appropriately applied to Delta's book value capitalization of 11.82% at the high stock price and 11.41% at the low stock price. These calculations in Exhibit MJB-8 were made using the sustainable growth rate of 2.37%. Similar calculations in Exhibit MJB-9 resulted in returns on equity that could be appropriately applied to Delta's book value capitalization of 14.07% at the high stock price and 13.43% at the low stock price. These calculations were made using the sustainable growth rate of 3.67%.

Q. DO THESE CALCULATIONS SEEM REASONABLE?

A. Yes. In fact, making the conversion from an ROE that should be applied to the value of market equity to an ROE that should be applied to book equity resolves a number of paradoxes that result from applying the ROE estimates from the DCF formula directly to the book equity component of Delta's capitalization. One thing that has always concerned me in performing DCF calculations was that the high stock price resulted in a lower calculated ROE than the low stock price. Looking at Exhibit MJB-8, the high stock price of $26.82 resulted in an ROE estimate of 6.84% while the low stock price of $24.11 resulted in an ROE estimate of 7.35%. This says that an investor would be willing to pay $26.82 for an investment generating a return on equity of 6.84% while he would only be willing to pay $24.11 for an investment generating a return on equity of 7.35%. This simply doesn't make sense if these calculated returns on equity are applied directly to book equity, which is $50,633,040 in this proceeding. A 7.35% return on book equity would be $3,721,528 annually while a 6.84% return on book equity would be $3,463,300 annually. What investor in their right mind would pay $24.11 per share for an investment generating $3,721,528 annually while paying $26.82 per share for an investment only generating $3,463,300 annually.

However, this does make sense if these calculated ROEs are applied to market capitalization. In Exhibit MJB-8, the ROE of 6.84% calculated using the high stock price is applied to the market capitalization of $87,460,932 and the result is an annual dollar flow of $5,986,065 that shareholders expect from this investment. Similarly, the ROE of 7.35% calculated using the low stock price is applied to the market capitalization of $78,623,530, which was also calculated using the low stock price, and the result is an annual dollar flow of $5,776,618 that shareholders expect from this investment. This makes sense. Investors would be willing to pay a higher price for a stock that generated a larger dollar flow and a lower stock price for an investment that generated a lower dollar flow. This sensible result does not occur when the ROEs calculated using DCF are applied directly to book equity.

Q. IS IT NECESSARY TO APPLY AN ESTIMATED RETURN ON EQUITY IN A MANNER THAT IS CONSISTENT WITH THE WAY THAT IT IS CALCULATED?

A. Yes. As discussed above, the DCF calculation determines what shareholders require from a company in terms of present and future dividends relative to the current market price of the company's stock. Thus, returns on equity estimated in this manner must be applied to the market capitalization which is also calculated using the current market price of the stock. The DCF methodology does not determine what shareholders require from a company in terms of present and future dividends relative to the company's book value of equity. Thus application of ROEs estimated using the DCF methodology directly to a company's book value of equity or rate base is an inconsistent and an inappropriate application of these estimates. It is taking an estimate generated for one purpose and using it for a completely different and unrelated purpose. The ROE estimates calculated using the DCF methodology can only be applied to book value equity after converting them for such use as shown in Exhibits MJB-8 and MJB-9.

Q. WHAT WOULD THE CAPITAL ASSET PRICING MODEL YIELD AS AN EXPECTED RETURN ON EQUITY FOR DELTA?

A. The CAPM approach could be utilized to estimate the return on equity for Delta. The basic CAPM formula is:

$$K = R_f + \exists\,(R_m - R_f)$$

where:

K = the prospective market cost of equity for a specific investment,

∃ = the company specific beta coefficient,

R_f = the risk free rate of return (usually U.S. Treasury bonds),

R_m = the overall stock market return, and

$R_m - R_f$ = the equity risk premium.

The Value Line Investment Survey - Small and Mid-Cap Edition (Exhibit MJB-10) provided an estimate for ∃ of 0.55 for Delta. Ibbotson's Risk Premia Over Time Report: 2006 (Exhibit MJB-6) calculated a long-horizon expected equity risk premium of 7.1% which was calculated as the difference between large company stock total returns minus long-term government bond returns for the period 1926 through 2005. With an interest rate on 20-Year U.S. Treasury bonds in the neighborhood of 5.0% during the period January 19, 2007 through February 2, 2007 (Exhibit MJB-11) and a beta coefficient of 0.55, the Capital Asset Pricing Model produces an initial estimated return on equity of 8.905% as shown in Exhibit MJB-12.

However, as noted in the Stocks, Bonds, Bills and Inflation 2003 Yearbook:

> Based on historical return data on the NYSE/AMEX/NASDAQ decile portfolios, the smaller deciles have had returns that are not fully explainable by the CAPM. This return in excess of CAPM, grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The excess return is especially pronounced for micro-cap stocks (deciles 9-10). This size related phenomenon has prompted a revision to the CAPM, which includes the addition of a size premium. (Stocks, Bonds, Bills and Inflation 2003 Yearbook, Ibbotson Associates, 2003, p. 135.)

The size premium that must be added to CAPM calculations to obtain the appropriate ROE estimates for micro-cap companies, such as Delta, is reported in Ibbotson's Risk Premia Over Time Report: 2006 as 9.83% (Exhibit MJB-6). This size premium was calculated from data for the period 1926 through 2005. When this 9.83% micro-cap size premium is added to the initial ROE estimate, the final estimate for ROE using the Capital Asset Pricing Model is 18.735% as shown in Exhibit MJB-12 and is calculated as:

ROE Estimate Including Micro-Cap Size Premium = 5.0 + (0.55 x 7.1) + 9.83 = 18.735.

Inclusion of this size premium is appropriate because not only does Delta fall within the micro-capitalization group as defined by Ibbotson, but as can be seen from Exhibit MJB-2, Delta has one of the smallest total capitalizations of the investor owned natural gas distribution companies in the panel.

Q. WHAT RATE OF RETURN ON EQUITY WOULD THE RISK PREMIUM INDICATE WAS APPROPRIATE?

A. The long-horizon expected equity risk premium reported in Risk Premia Over Time Report: 2006 (Exhibit MJB-6) by Ibbotson Associates is 7.1% calculated by subtracting long-term government bond returns from large company stock total returns for the period 1926 to 2005. This estimate of the risk premium is calculated using a past average of ex-post risk premiums over a sufficiently long period of time to include several ups and downs in dividend yields and provides a good estimate of the future risk premium. This long-horizon expected equity risk premium was calculated using stock market data for the companies in the Standard and Poor's 500 Index and for U. S. Treasury Bonds having a 20-year maturity. The interest rate on 20-Year U.S. Treasury bonds was in the neighborhood of 5.0% during the period January 19, 2007 through February 2, 2007 as reported by FRED® [Federal Reserve Economic Data] available on the Federal Reserve Bank of St. Louis web site (Exhibit MJB-11). Adding the long-horizon risk premium of 7.1% to the 20-year U.S. Treasury bond yield of 5.0% produces a return on equity of 12.1%. It is important to note that the risk premium of 7.1% was calculated using large company stock data and that an appropriate return for a smaller company, like Delta, should be higher. However, these estimated returns on equity for the market as a whole do help to demonstrate that the estimated returns on equity for Delta using the DCF and capital asset pricing model results discussed earlier are reasonable.

Q. WHAT IS A REASONABLE RANGE FOR THE RETURN ON EQUITY IN THIS PROCEEDING?

A. Based on the above analysis, a reasonable range for return on equity in this proceeding would be between 11.17% and 18.73% as summarized in the table below.

Method	**ROE Range**	
	High	**Low**
DCF (Sustainable Growth)	11.82%	11.41%
DCF (Average panel growth)	14.07%	13.43%
CAPM	18.73%	18.73%
Risk Premium	12.1%	12.1%

These estimates do not make any adjustment for Delta's lower than average percentage of equity in its total capitalization compared to other natural gas distribution companies in the panel.

Q. WHAT RETURN ON EQUITY DO YOU RECOMMEND BE UTILIZED IN CALCULATING THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. I recommend using a 12.1% return on equity in this proceeding, which is the return on equity derived using the risk premium approach. The risk premium approach is simple and straightforward and does not require that the Commission directly address the adjustments necessary to apply the return on equity derived using the DCF methodology to book value equity. The adjustments for converting the returns on equity that were derived from data that reflect the market value of equity to returns on equity that could be applied to book value equity is new ground for the Commission. In this testimony, I will use these adjustments to demonstrate that the return on equity I am recommending is well within the reasonable range rather than confront the Commission with a new approach for applying DCF on which it would need to rule in this proceeding. This will provide the Commission with ample time to carefully consider and research this approach before ruling on it in future proceedings. The 12.1% that I am recommending is well within the reasonable range as indicated by my analysis. In determining the appropriate return on equity for Delta, the Commission needs to consider that Delta is different than the other investor owned utilities that the Commission regulates. Delta is the smallest investor owned natural gas utility that the Commission regulates with one of the lowest equity ratios in the industry. The size premium for small companies is well documented and has been calculated based on a data set that covers a number of economic cycles that include both wars and a depression. In deciding on the appropriate return on equity for Delta and whether it is appropriate to approve the experimental CRS mechanism that Delta is requesting in this proceeding, it is important for the Commission to note that Delta has not earned its allowed rate of return in any of the past 12 years (Exhibit MJB-4). Additionally, Delta's low percentage of equity compared to other natural gas distribution companies makes it harder for Delta to earn any rate of return allowed by the Commission as illustrated in Exhibits MJB-4 and MJB-5. This is particularly true when combined with factors such as the financial hit that Delta experiences from financing deferred gas costs with no interest recovery. After analyzing all of the relevant factors, I believe that 12.1% is a reasonable return on equity for Delta in this proceeding if this return on equity is applied to the book equity component of Delta's capitalization and the Commission approves the experimental CRS mechanism that Delta is requesting. If the Commission does not approve the experimental CRS mechanism that Delta is requesting, a higher allowed rate of return would be appropriate so that Delta has a real opportunity to earn the return on equity that the Commission allows.

Q. DOES THE RETURN ON EQUITY THAT YOU RECOMMEND PRODUCE A REASONABLE RESULT?

A. Yes. Exhibits MJB-14 and MJB-15 calculate estimated returns on equity for the other fourteen companies in the Edward Jones panel of natural gas distribution companies using a discounted cash flow analysis and the capital asset pricing model. Exhibit MJB-14 calculates the estimated returns on equity for these companies using sustainable growth rates for the companies from the Value Line Investment Survey - Small and Mid Cap Edition, for which forecasted dividend growth rates were not reported, while Exhibit MJB-15 makes the DCF calculations using the average growth rate for the other nine companies in the panel for these companies. All of the other data for calculating estimated returns on equity using the DCF model and the CAPM model come from the September 15, 2006 edition of Value Line (Exhibit MJB-16). Calculations were not made for SEMCO Energy because it paid no dividends which made calculation of an estimated return on equity using the DCF methodology impossible. In Exhibit MJB-14, the average return on book equity for the panel of natural gas distribution companies was 14.7% using the high stock price and 12.97% using the low stock price based on the DCF methodology using sustainable growth rates for companies without forecasted dividend growth rates in Value Line (Exhibit MUB-14, page3). In Exhibit MJB-15, the average return on book equity for the panel of natural gas distribution companies using the average growth rate for the companies in the panel without forecasted dividend growth rates in Value Line and using the DCF methodology was 14.43% using the high stock price and 12.86% using the low stock price. Thus, based on similar DCF calculations for companies in the Edward Jones panel, the recommended 12.1% return on equity for Delta is below all of these average returns on equity and is very reasonable.

The CAPM results in Exhibits MJB-14 and MJB-15 are calculated using a risk free rate of return of 5.0% which was the value around which the yield on 20-Year Treasury Bonds fluctuated during the period January 19, 2007 through February 2, 2007. It also uses a long-horizon equity premium of 7.1% and a size premium that is appropriate for the utility's total capitalization from Risk Premia Over Time Report: 2006 by Ibbotson Associates. The calculations for the remaining companies in the panel in MJB-14 show that the average return on equity calculated using CAPM was 13.94% (Exhibit MJB-14, page 1). Again, the 12.1% return on equity that I recommend for Delta is very reasonable compared to this average.

Q. CAN YOU PROVIDE ADDITIONAL EVIDENCE THAT THE RETURN ON EQUITY THAT YOU RECOMMEND PRODUCES A REASONABLE RESULT?

A. Yes. As discussed above, it is important to note that the U.S. Supreme Court did not limit the return on equity to being commensurate with other utilities. It stated that the return on equity should be commensurate with other companies having corresponding risk. Thus, I did a search for companies in the Value Line Investment Survey - Small and Mid Cap Edition that had total assets of less than $200 million and a beta coefficient of between 0.50 and 0.60. The results of this search are contained in Exhibit MJB-17. A search using these parameters takes account of both the risk captured in the calculation of beta and also the size related risk that is not captured in beta, as noted by Fama and French in the research cited above. One advantage that this panel has is that the returns on equity for these companies have not been determined by regulatory commissions, but by the market. The Return on Shareholder Equity for 2005, the last full year reported for all companies, and the five-year total shareholder returns that includes both appreciation and dividends are reported in Exhibit MJB-18. The average return on equity for unregulated companies of corresponding size and risk was 12.96% and the median return on equity was 13.5%. Furthermore, the five-year total shareholder returns are about 4 times smaller for Delta than for unregulated companies of corresponding size and risk. These results for unregulated companies of corresponding size and risk show that the 12.1% return on equity that I am recommending for Delta is very reasonable.

Q. HOW DOES THE INTEREST COVERAGE FOR DELTA COMPARE TO THE INTEREST COVERAGE FOR THE OTHER NATURAL GAS DISTRIBUTION COMPANIES IN THE EDWARD JONES PANEL IF THE COMMISSION WERE TO ALLOW DELTA A 12.1% RETURN ON EQUITY?

A. Exhibit MJB-19 shows the interest coverage for the 15 natural gas distribution companies in the panel reported by Edward Jones, which is calculated by dividing net income plus interest on long term debt by the interest on long term debt. Delta has an interest coverage of 2.56x, which is third lowest in the panel of natural gas distribution utilities covered in the report. The mean interest coverage for the panel is 3.26x with a median interest coverage of 3.18x. If the revenue requirement for Delta is determined based on a 12.1% return on equity and based on the capital structure in this proceeding, the resulting interest coverage would be 2.66x. As can be seen from Exhibit MJB-19, the resulting interest coverage from using a 12.1% rate of return would still be the fourth lowest in the panel and well below the mean and median interest coverages for the fifteen natural gas distribution companies included in the Edward Jones report. Based on the resulting level of interest coverage compared to natural gas distribution industry averages, I believe that application of the recommended 12.1% rate of return on equity to the existing capital structure is reasonable. It would take even a higher rate of return on equity to produce a level of interest coverage and an equity ratio that is more representative of the other companies in the panel of natural gas distribution companies. The revenue requirement that would result from utilizing the 12.1% return on equity that I recommend would be a start to increasing Delta's equity ratio to a level more appropriate for a natural gas distribution company of Delta's size, and to increasing the interest coverage to a level that is closer to the industry average. However, even when this recommended ROE is placed into effect, it will take several years before there is significant improvement in these key financial measures.

Experimental Customer Rate Stabilization Mechanism

Q: PLEASE EXPLAIN WHY THE EXPERIMENTAL CRS MECHANISM THAT DELTA IS PROPOSING IS APPROPRIATE.

A: Delta's current rate design recovers a significant portion of its fixed costs and margins through a volumetric charge assessed on a CCF basis. The customer charge of $19.74 per customer per month that is being proposed for the residential class in this proceeding does not fully cover the customer related fixed costs and margins identified in the cost of service study. Mr. Seelye's testimony shows that a large portion of Delta's customer related fixed costs will be recovered through volumetric charges under Delta's proposed rates. The remaining customer related fixed costs are recovered through a volumetric charge along with the costs that are identified as demand related in the cost of service study. Thus, Delta's recovery of fixed cost and margin is heavily dependent on its ability to achieve a throughput volume per customer in the future that equals that which is used in designing the rates that the Commission approves here. Per customer volumes higher than those used in designing the rates in this proceeding will result in an over-recovery of fixed costs and margins, while volumes lower than those used in designing the rates will result in an under-recovery of fixed costs and margins. Delta has experienced a consistently declining use per customer over the past ten years which has contributed significantly to Delta not earning its allowed rate of return in any of these years, as shown in Exhibit MJB-4. If this declining trend in customer use continues, Delta will not have a reasonable opportunity to earn its allowed rate of return. Delta's proposed CRS mechanism would adjust for this problem and result in Delta actually having a fair opportunity to earn the rate of return allowed by the Commission. Delta has invested in plant to meet its customers' needs in good faith which has resulted in significant fixed costs that must be recovered. Delta should not be penalized with a lower earned rate of return because of an on-going downward trend in natural gas usage per customer. It would not be appropriate for the Commission to ignore this downward trend and, in effect, make it essentially impossible for Delta to earn the rate of return that the Commission will identify as fair in this proceeding.

Q: WOULD THE PROPOSED CRS MECHANISM BE DUPLICATIVE OF THE CEP MECHANISM THAT IS ALSO BEING PROPOSED IN THIS PROCEEDING?

A: No. The CEP mechanism would break the linkage between the volume of natural gas used and fixed cost and margin recovery only for those customers participating in the CEP. The CEP mechanism is a targeted mechanism that would only adjust for lost revenues resulting from customers participating in any of the three components of the CEP, and would not adjust for under-recovery of fixed costs and margin due to a declining trend in per customer volumes.

Q: HAVE RATE STABILIZATION MECHANISMS SIMILAR TO THE PROPOSED CRS BEEN ADOPTED BY OTHER STATE REGULATORY COMMISSIONS?

A: Yes. Both Alabama and South Carolina employ rate stabilization mechanisms similar to the CRS that Delta is proposing in this proceeding. Alabama Gas Company has had a Rate Stabilization and Equalization ("RSE") mechanism in place since 1983. When the Alabama Public Service Commission originally approved the RSE mechanism for Alabama Gas Company in 1983, it found that:

> the ratemaking principles reflected in Rate RSE...constitute a significantly improved method of setting natural gas utility rates sufficient to provide the Company with stable and adequate returns, to provide the public with the lowest possible rates consistent with the cost of service, to ameliorate the impact of increases required, and to decrease rates promptly if the designate rates of return are exceeded." Alabama Gas Corporation, Dockets 18046, 18328 and 18622, Order p. 3 (Jan. 25, 1983).

When the Alabama Public Service Commission renewed its approval of the RSE mechanism in 2002, it found that:

> The Commission herein reaffirms that after nineteen years of successful operation, Rate RSE is an appropriate and effective ratemaking mechanism for the consumers of Alabama and for the Company. ... In addition, RSE's implementation and continuation as a regulatory tool in Alabama has streamlined and stabilized the regulatory and ratemaking process, has replaced the Company's requests for large, complicated rate increases with quarterly rate adjustments that are easier to understand, less significant and easier to monitor, and has enhanced the effectiveness and reduced the cost of utility regulation in Alabama. Alabama Gas Corporation, Dockets 18046 and 18328, Order p. 3 (June 10, 2002).

From this language, it is clear that the Alabama Public Service Commission believes that rate stabilization mechanisms similar to the one proposed by Delta here benefit both the utility and its ratepayers.

Q: WHAT HAS BEEN THE EXPERIENCE WITH RATE STABILIZATION MECHANISMS IN SOUTH CAROLINA?

A: South Carolina has adopted legislation entitled "The Natural Gas Rate Stabilization Act" which allows utilities to elect to have their rates regularly adjusted pursuant to the provisions of the Act. Quarterly rate adjustments are made to keep the natural gas utility's cost of equity within a 1% band specified by the South Carolina Public Service Commission. This 1% band includes a range of 0.5% below and 0.5% above the cost of equity on which rates have been set. If the natural gas utility's earnings exceed the upper end of the range established by the Commission, the utility's rates are reduced to lower its return on equity to the midpoint of the range that the Commission set. If the natural gas utility's earnings are below the lower range established by the Commission, the utility's rates are increased to raise its return on equity to the midpoint of the range that the Commission set. The experimental CRS that is being proposed by Delta includes the same 1% band feature that has been used successfully in other jurisdictions such as South Carolina.

Q: IS IT NECESSARY TO REDUCE THE RATE OF RETURN ON EQUITY TO ACCOUNT FOR DECREASED RISK IF THE CRS MECHANISM THAT IS BEING PROPOSED BY DELTA IS APPROVED BY THE COMMISSION IN THIS PROCEEDING?

A: Based on a recent decision by the Alabama Public Service Commission, which has over 20 years experience with rate stabilization mechanisms similar to the one being proposed by Delta, it does not appear that such a reduction is necessary. An Order in a case setting rates for Mobile Natural Gas Company issued on June 10, 2002, stated that:

> As noted in the Commission's Report and Order dated October 3, 2001, in this docket, the Attorney General agreed in concept not to oppose the Company's regulation under Rate RSE or any similar regulatory treatment. The Attorney

> General also agreed to incorporate the rate of return on common equity developed in this docket (13.60%) into the Company's proposed RSE tariff. Rate RSE requires a range of rate of return on average common equity and the parties agreed that, for evaluation purposes, the range would be from 13.35% to 13.85%, with a mid-point of the 13.60%. Mobile Gas Service Corporation, Docket 28101, Order p. 2 (June 10, 2002).

A midpoint of 13.6% is consistent with the estimated rates of return reported earlier in my testimony and does not indicate that a downward adjustment was made for any reduced risk that the company might experience. Indeed, since the company is simply being allowed a real opportunity to actually earn the return on equity that the Commission found to be fair, no such adjustment is necessary or appropriate. Later in the same Order the Alabama Commission went on to state that:

> RSE's implementation and continuation as a regulatory tool in Alabama has streamlined and stabilized the regulatory and ratemaking process, has replaced the Company's requests for large, complicated rate increases with quarterly rate adjustments that are easier to understand, less significant and easier to monitor, and has enhanced the effectiveness and reduced the cost of utility regulation in Alabama. Mobile Gas Service Corporation, Docket 28101, Order p. 4 (June 10, 2002).

This statement reflects the Alabama Public Service Commission's belief that the rate stabilization mechanisms that it has approved for natural gas utilities are an improvement over the rate cases that natural gas companies filed before the use of this mechanism. I believe that similar benefits could be achieved through the use of the CRS mechanism that Delta is proposing for use in Kentucky.

Consumer Conversation and Efficiency Program

Q: IS THE RATE TREATMENT THAT DELTA IS REQUESTING FOR ITS CONSUMER CEP CONSISTENT WITH FEDERAL ENERGY POLICY?

A: Yes. Provisions of the Energy Policy Act of 1992 that are codified as 15 USC § 3202 establish the following Federal standard:

> Investments in conservation and demand management. The rates charged by any State regulated gas utility shall be such that the utility's prudent investments in, and expenditures for, energy conservation and load shifting programs and for other demand-side management measures which are consistent with the findings and purposes of the Energy Policy Act of 1992 are at least as profitable (taking into account the income lost due to reduced sales resulting from such programs) as prudent investments in, and expenditures for, the acquisition or construction of supplies and facilities. This objective requires that (A) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (B) regulators ensure that, for purposes of recovering fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volumes. (15 USC § 3202(b)(4))

Delta's proposed CEP Mechanism consists of three components designed to promote reductions in demand for natural gas that will benefit Delta's customers. The three components of the CEP are: 1) high efficiency appliances, 2) home energy audits and 3) customer awareness. These three components promote conservation and reduced usage of natural gas by residential customers and are consistent with the purposes of the Energy Policy Act of 1992. Thus, pursuant to these Federal standards, it would be appropriate for the Commission to allow Delta to recover the cost of implementing these programs, an incentive for pursuing these demand side programs and recovery of lost sales resulting from these programs.

Q: IS THE RATE TREATMENT THAT DELTA IS REQUESTING FOR ITS CEP CONSISTENT WITH KENTUCKY STATUTES?

A: Yes. The provisions in Kentucky Statutes that authorize the Commission to grant the rate treatment that Delta is seeking for its CEP are contained in KRS 278.285 which states as follows:

> A proposed demand-side management mechanism including:
>
> (a) Recover the full costs of commission-approved demand-side

> management programs and revenues lost by implementing these programs;
> (b) Obtain incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs; or
> (c) Both of the actions specified
>
> may be reviewed and approved by the commission as part of a proceeding for approval of new rate schedules initiated pursuant to KRS 278.190 or in a separate proceeding initiated pursuant to this section which shall be limited to a review of demand-side management issues and related rate-recovery issues as set forth in subsection (1) of this section and in this subsection. (KRS 278.285(2))

Thus, it would be appropriate for the Commission to allow Delta to recover the cost of implementing the CEP programs, an incentive for pursuing these demand side programs and recovery of lost sales resulting from these programs.

Q: WOULD THE CEP MECHANISM THAT DELTA IS PROPOSING IN THIS PROCEEDING REMOVE A SIGNIFICANT DISINCENTIVE FOR DELTA TO PURSUE DEMAND SIDE MANAGEMENT AND ENERGY CONSERVATION PROGRAMS?

A: Yes. Delta's current rate design recovers a significant portion of its fixed costs and margin through a volumetric charge per CCF. This existing volumetric rate design tends to force natural gas utilities to choose between either advocating conservation or attempting to achieve adequate financial performance by selling more gas. However, if the relationship between cost recovery and customer throughput is severed with regard to CEP participation, as Delta is proposing, Delta can both recoup its legitimate costs and sponsor conservation efforts without harming its shareholders.

In July 2004, the AGA and the Natural Resources Defense Council ("NRDC") issued a Joint Statement titled "Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency," which discussed the fact that the vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, Delta's current rates are designed to capture a large portion of its approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that Delta can recover these costs fully only if its customers consume a certain minimum amount of natural gas. The AGA and NRDC Joint Statement went on to state that:

> When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole.

Delta's proposed CEP mechanism would sever the relationship between cost recovery and customer throughput with regard to CEP participation and would remove a significant disincentive for Delta to aggressively purse demand side management programs.

Q: DOES THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS ENCOURAGE THE ADOPTION OF RATE MECHANISMS FOR NATURAL GAS THAT PROVIDE INCENTIVES FOR ENERGY CONSERVATION?

A: Yes. On November 16, 2005 at its annual convention in Indian Wells, California, the National Association of Regulatory Utility Commissioners ("NARUC") adopted a resolution that encouraged "State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices." This NARUC resolution stated that energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers and recognized that current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers. The CEP mechanism that Delta is proposing in this proceeding would correct this misalignment for customers participating in the CEP program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

Prior Testimony of Dr. Martin J. Blake

Federal Energy Regulatory Commission

ER92-533	LG&E's open transmission access and authority to charge market-based rates for its generation.
ER94-1380	The first comparability tariff approved by the FERC.
ER97-4345	A market power analysis that was filed in support of OGE Energy Resources, Inc.'s request for the authority to charge market based rates.
ER98-511	A market power analysis that was filed in support of Oklahoma Gas and Electric Co.'s request for the authority to charge market based rates.
ER99-51	An affidavit in support of Commonwealth Edison Co.'s request for authority to charge cost based rates to its affiliates.
ER01-1938	Testimony in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
ER02-708	Testimony in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
NJ03-2	Testimony in support of Southern Illinois Power Company's request for a revision in ancillary service rates
EL03-53	Testimony regarding the calculation of avoided cost for a qualifying facility interconnecting with a cooperative
EL02-111	Testimony regarding the process for developing a combined transmission service rate that would apply to the combined Midwest ISO and PJM footprint

Arkansas Public Service Commission

96-360-U	Direct and rebuttal testimony for Oklahoma Gas and Electric regarding recovery of stranded costs by Entergy Arkansas, Inc.

California Public Utility Commission

90-12-018 (phase 5)	Direct and rebuttal testimony for Southern California Edison Company concerning the reasonableness of contracting by Southern California Edison with Integrated Energy Group ("IEG") to provide marketing services to Southern California Edison and the reasonableness of the resulting marketing services performed by IEG.

Illinois Commerce Commission

98-0013 and 98-0035	Testimony regarding non-discrimination with regard to affiliate transactions for electric utilities. I sponsored ComEd's proposed affiliate transactions rules and suggested some basic principles that the Illinois Commerce Commission should follow in developing rules and regulations for ensuring non-discrimination and non-cross subsidization in transactions with affiliated and unaffiliated alternative retail electric suppliers ("ARES").
98-0036	Testimony in a rulemaking to develop rules and regulations for assessing and assuring the reliability of the transmission and distribution systems as a part of electric utility restructuring in Illinois.
98-0147 and 98-0148	Testimony concerning standards of conduct and rules for functional separation. I sponsored ComEd's proposed standards of conduct and functional separation rules.

Kentucky Public Service Commission

90-158	An LG&E rate case.
92-494	An LG&E biennial fuel adjustment clause review.
93-150	An application for approval of a DSM cost recovery mechanism and a set of initial programs.
94-332	An application for an environmental cost recovery mechanism.
92-494-B	Testimony regarding the confidentiality of coal bid data.
95-455	A biannual review of the environmental cost recovery mechanism.
91-423	Participation in the conference with Commission staff and intervenors to review LG&E's first integrated resource plan.
Other	Several fuel adjustment clause proceedings on behalf of LG&E.

98-489	Testimony on behalf of Blazer Energy Corp. in an application for an adjustment in their natural gas rates.
99-046	Direct and rebuttal testimony regarding Return on equity in support of Delta Natural Gas Company's request for an adjustment in rates
04-00067	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

Nevada Public Utility Commission

01-10001	Direct testimony on behalf of Shareholders Association to support Nevada Power Company's request for return on equity

New Mexico Public Utility Commission

2797	Direct and rebuttal testimony in a general rate case for Plains Electric Generation and Transmission Cooperative, Inc.

Oklahoma Corporation Commission

PUD 960000116	Testimony in an Oklahoma Gas and Electric Company rate case, including rebuttal of intervenor and staff proposals to disallow certain marketing, advertising, economic development and research and development expenses.
PUD 200300226	Testimony in an Oklahoma Gas and Electric Company case regarding the prudence of natural gas transportation and storage contracts

Indiana Utility Regulatory Commission

41884	Direct and rebuttal testimony to support a request by eleven gas local distribution companies for switching from a quarterly gas cost adjustment mechanism to a monthly gas cost adjustment mechanism
42027	Direct testimony in.support of a transfer of functional control of transmission assets from electric utilities in Indiana to the Midwest System Operator, Inc.

Colorado Public Utility Commission

02S-594E	Direct and surrebuttal testimony regarding pro forma adjustments to the revenue requirement in Aquila Networks-WPC rate case.

03S-539E Testimony regarding the use of zero intercept methodology to allocate distribution costs and determine an appropriate customer charge in an Aquila Networks-WPC rate case.

Iowa District Court for Hamilton County

No. LACV025993 Testimony that net metering was not appropriate for making payments to a wind generator. When a utility sells electric energy to a customer, it is charging a retail rate that recovers the cost of distribution, transmission and generation service. When a customer sells electric energy to a utility, it is selling only generation service. The customer cannot sell distribution and transmission service to a utility, as the customer does not own these assets. Net metering is a subsidy to the wind generator that is paid by other customers of the utility and paying the customer for generation service on the basis of a retail rate that includes recovery of distribution and transmission costs is not appropriate.

Exhibit MJB - 2
Edward Jones Natural Gas Industry Summary Data
Ranked by Total Capitalization

	12 Months Ending		Total Capitalization (in $1,000)	Precent Equity
Atmos Energy Corp.	9/30/2006	$	3,828,460	43%
AGL Resources, Inc.	9/30/2006	$	3,252,000	49%
Peoples Energy Corp.	9/30/2006	$	1,736,156	48%
Piedmont Natural Gas Company	7/31/2006	$	1,727,021	52%
WGL Holdings,Inc.	9/30/2006	$	1,471,760	63%
Northwest Natural Gas Company	9/30/2006	$	1,084,443	55%
New Jersey Resources, Inc.	9/30/2006	$	953,994	65%
Laclede Group	9/30/2006	$	798,865	50%
South Jersey Industries, Inc.	9/30/2006	$	791,191	55%
SEMCO Energy, Inc.	9/30/2006	$	693,530	30%
Cascade Natural Gas Corp.	9/30/2006	$	287,250	43%
EnergySouth, Inc.	9/30/2006	$	188,245	59%
Delta Natural Gas Company	**9/30/2006**	**$**	**109,995**	**47%**
RGC Resources, Inc.	9/30/2006	$	70,495	57%
Energy West	9/30/2006	$	36,276	52%
	Average	$	1,135,312	51%
	Median	$	798,865	52%

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2006

Exhibit MJB-3

The earnings performance for many Natural Gas (Distribution) companies has been hurt by warmer-than-normal temperatures and conservation by customers. To offset the losses, many companies have recently been applying for regulatory policies that protect against both of these issues (discussed below). Moreover, it should be noted that the key features of owning a utility stock are their Safety and better-than-average dividend yields, rather than price performance or appreciation potential. However, with interest rates at higher levels compared to the past few years, some of the positive attributes of owning these stocks may be reduced.

Regulated Gas Utilities

The distribution operations of gas utilities are regulated by state agencies, which set the allowed rates of return these companies are permitted to earn. The utilities are considered natural monopolies since it is more cost-effective to build one pipeline system to serve a region, versus multiple distributors competing over the same location. One typical benefit of an investment in these companies is earnings stability, since utilities can file for rate adjustments should operating costs cut into profitability. For example, *WGL Holdings* plans to file for a rate increase with the Maryland Public Service Commission next spring to recover costs associated with its Prince George's County rehabilitation project. Likewise, *SEMCO* has a request on file with the Michigan Public Service Commission for an $18.9 million increase in base rates, with hearings scheduled to start shortly on this matter. Rate relief can lag at times, though.

In addition, there are numerous companies that have either received or are petitioning to have weather normalization and/or conservation and usage clauses put in place. *Atmos Energy* will have weather-normalized rates in place beginning October 1st at its Mid-Tex operations. *South Jersey Industries* and *New Jersey Resources* both have proposed a conservation and usage adjustment proposal with the New Jersey Board of Public Utilities. This would provide protection against both temperature deviations and usage changes, while better aligning the utilities' interests with those of its customers. Both companies are optimistic that the request will be granted. Moreover, it would not be surprising to see other companies in this industry file for similar plans in the future, which would further strengthen the consistency of earnings.

INDUSTRY TIMELINESS: 82 (of 97)

Nonutility Operations

Many gas utilities have expanded outside their core distribution operations into nonregulated operations such as retail energy marketing, energy trading, and oil and gas exploration. In fact, most companies in this industry have some portion of their earnings coming from nonregulated activities, with many looking to boost their percentage of earnings from this segment in the coming years. However, the one drawback from an increased presence in nonregulated activities is that regulatory agencies seem less likely to approve rate increases. This is the tradeoff faced, since nonregulated operations have no restrictions on permitted return on equity. *Laclede Group's* nonutility operations are growing. Its energy resources segment continues to benefit from supply/demand imbalances that resulted from last year's Gulf Coast hurricanes. Investors who are particularly interested in those companies with a more pronounced nonregulated segment should take a look at *Southern Union*. The company recently sold two of its distribution assets to purchase midstream assets. In addition, the company has growth opportunities at its Trunkline LNG unit.

Investment Advice

The stocks in this untimely industry are generally suitable for income-oriented investors, and offer good stock price stability. Even so, there is a great deal of diversity among the stocks in this industry, most notably between those that have operations in nonregulated activities. As companies shift toward these businesses, they increase the potential for capital appreciation, but at the cost of heightened share-price volatility. Therefore, we recommend that conservative investors consider a company's balance between utility and nonutility activities before committing funds. Note, however, that especially high dividend yields for stocks in this sector can mean that growth opportunities are constrained.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2002	2003	2004	2005	2006	2007		09-11
22947	29981	33220	41399	*44500*	*49000*	Revenues ($mill)	*58000*
1231.5	1395.3	1517.2	1788.8	*2000*	*2200*	Net Profit ($mill)	*2800*
35.3%	37.4%	35.7%	35.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
5.4%	4.7%	4.6%	4.3%	*4.5%*	*4.5%*	Net Profit Margin	*4.8%*
57.8%	55.9%	53.2%	50.7%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
41.4%	43.7%	45.7%	48.3%	*46.0%*	*46.0%*	Common Equity Ratio	*46.0%*
24907	28436	31268	33911	*35400*	*36750*	Total Capital ($mill)	*42000*
25590	31732	32053	35030	*37000*	*39000*	Net Plant ($mill)	*45000*
6.6%	6.4%	6.4%	6.9%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
11.7%	11.1%	10.4%	10.7%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.8%	11.2%	10.5%	10.8%	*11.0%*	*11.5%*	Return on Com Equity	*12.0%*
3.9%	4.1%	4.0%	4.4%	*5.0%*	*5.2%*	Retained to Com Eq	*5.5%*
68%	64%	63%	59%	*61%*	*60%*	All Div'ds to Net Prof	*60%*
14.8	14.1	15.6	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.81	.80	.82	.87	*Value Line*		Relative P/E Ratio	*.85*
4.5%	4.5%	4.0%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*
281%	314%	308%	331%	*315%*	*330%*	Fixed Charge Coverage	*355%*

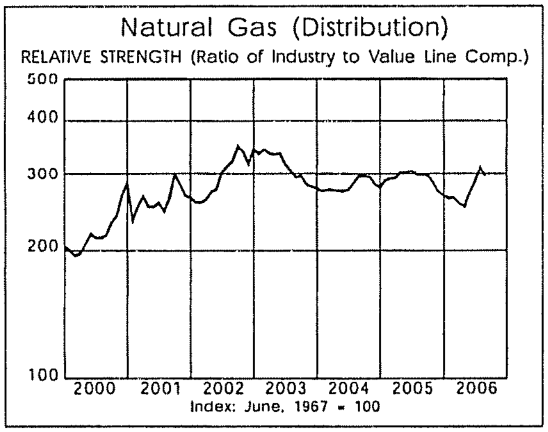


Exhibit MJB - 4
Historical Comparison of Allowed and Actual ROE
Delta Natural Gas Company

	Return on Shareholder Equity	Allowed ROE	Difference	
1995	8.50%	Black box settlement in last rate case		
1996	11.30%	Black box settlement in last rate case		
1997	5.80%	Black box settlement in last rate case		
1998	8.20%	11.60%	-3.40%	New Rates Effective Jan. 1998
1999	7.20%	11.60%	-4.40%	
2000	11.10%	11.60%	-0.50%	New Rates Effective Jan. 2000
2001	11.10%	11.60%	-0.50%	
2002	10.60%	11.60%	-1.00%	
2003	8.60%	11.60%	-3.00%	
2004	7.90%	10.50%	-2.60%	New Rates Effective Oct. 2004
2005	9.80%	10.50%	-0.70%	
2006	9.50%	10.50%	-1.00%	
Mean	**9.13%**			

Data Source:

The Value Line Investment Survey - Small and Mid-Cap Edition, Dec. 19, 2003

Exhibit MJB - 5
Examples of the Impact of Leverage on Actual Return on Equity

Example 1

	Capitalization	Ratios	Cost Rates	Return Element in Dollars
Equity	$52,115,554	0.4036	12.50%	$ 6,514,444
Debt	$77,016,346	0.5964	7.00%	$ 5,391,144
	$129,131,900	1		$ 11,905,588

Assume $2,000,000 shortfall in earnings

Actual Return on Equity = $4,514,444 / $52,115,554
= 8.66%

Example 2

	Capitalization	Ratios	Cost Rates	Return Element in Dollars
Equity	$65,857,269	0.51	12.50%	$ 8,232,159
Debt	$63,274,631	0.49	7.00%	$ 4,429,224
	$129,131,900	1		$ 12,661,383

Assume $2,000,000 shortfall in earnings

Actual Return on Equity = $6,232,159 / $65,857,269
= 9.46%

Example 3

	Capitalization	Ratios	Cost Rates	Return Element in Dollars
Equity	$129,131,900	1.0000	12.50%	$ 16,141,488
Debt	$0	0.0000	7.00%	$ -
	$129,131,900	1		$ 16,141,488

Assume $2,000,000 shortfall in earnings

Actual Return on Equity = $14,141,488 / $129,131,900
= 10.95%

Table 2 Key Variables in Estimating the Cost of Capital

(As of Year-end 2005)

	Value
Yields (Riskless Rates)[3]	
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	4.6%
Equity Risk Premium[4]	
Long-horizon expected equity risk premium (historical): large company stock total returns minus long-term government bond income returns	7.1%
Long-horizon expected equity risk premium (supply side): historical equity risk premium minus price-to-earnings ratio calculated using three-year average earnings	6.3%

Size Premium[5]

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid-Cap, 3-5	$1,729.364	-	$7,187.244	1.02%
Low-Cap, 6-8	$587.243	-	$1,728.888	1.81%
Micro-Cap, 9-10	$1.079	-	$586.393	3.95%
Breakdown of Deciles 1-10				
1-Largest	$16,091.015	-	$367,495.144	-0.37%
2	$7,189.887	-	$16,016.450	0.67%
3	$3,968.998	-	$7,187.244	0.85%
4	$2,525.472	-	$3,961.425	1.10%
5	$1,729.364	-	$2,519.280	1.49%
6	$1,282.276	-	$1,728.888	1.73%
7	$872.443	-	$1,280.966	1.67%
8	$587.243	-	$872.103	2.33%
9	$265.056	-	$586.393	2.76%
10-Smallest	$1.079	-	$264.981	6.36%
Breakdown of the 10th Decile				
10a	$169.245	-	$264.981	4.39%
10b-Smallest	$1.079	-	$169.195	9.83%

[3] As of December 31, 2005. Maturity is approximate.
[4] See Chapter 5 of Ibbotson's *SBBI Valuation Edition Yearbook* for complete methodology.
[5] Expected return in excess of that predicted by the capital asset pricing model, also known as the beta-adjusted size premium. Underlying data provided by CRSP, the Center for Research in Security Prices. See Chapter 7 of Ibbotson's *SBBI Valuation Edition Yearbook* for methodology.

Exhibit MJB-7
U.S. Natural Gas Prices

Date	U.S. Natural Gas Wellhead Price (Dollars per MCF)	City Gate Price (Dollars per MCF)
Nov-2004	$6.21	$7.50
Dec-2004	$6.01	$7.49
Jan-2005	$5.80	$7.05
Feb-2005	$5.74	$7.09
Mar-2005	$5.95	$7.24
Apr-2005	$6.58	$7.79
May-2005	$6.24	$7.51
Jun-2005	$6.09	$7.30
Jul-2005	$6.71	$7.68
Aug-2005	$6.48	$8.20
Sep-2005	$8.96	$10.26
Oct-2005	$10.35	$12.16
Nov-2005	$9.91	$11.57
Dec-2005	$9.08	$10.77
Jan-2006	$8.66	$10.66
Feb-2006	$7.28	$9.27
Mar-2006	$6.52	$8.74
Apr-2006	$6.59	$8.11
May-2006	$6.19	$7.86
Jun-2006	$5.80	$7.22
Jul-2006	$5.82	$7.13
Aug-2006	$6.51	$7.97
Sep-2006	$5.51	$7.59
Oct-2006	$5.03	$6.38
Nov-2006	$6.43	$8.39

Source: U.S. Depatment of Energy, Energy Information Administration

Exhibit MJB - 8
Results of DCF Model for Delta Natural Gas Company
Using Sustainable Growth Rate

		Variable Name
2006 Annual Dividend	$1.20	D
High Price During 2006	$26.82	P
Low Price During 2006	$24.11	P
Sustainable Growth Rate	2.37%	g
Shares Outstanding	3,261,034	
Earnings per Share in 2006	$1.55	
Book Equity	$ 50,633,040	

Sustainable Growth Rate

Payout Ratio = $1.20 / $1.55 =	0.7742
Retention Ratio = 1 - 0.07742 =	0.2258
Delta Allowed ROE	10.5%
Sustainable Growth Rate = b x r =	2.37%

Using the DCF formula: ROE = D/P + g

ROE Based on the 2006 High Stock Price

ROE = (1.20 / 26.82) + .0237 = 6.84%

ROE Based on the 2006 Low Stock Price

ROE = (1.20 / 24.11) + .0237 = 7.35%

Market Capitalization 2006 High Stock Price

3,261,034 x 26.82 = $87,460,932

Market Capitalization 2006 Low Stock Price

3,261,034 x 24.11 = $78,623,530

Expected Shareholder Returns High Stock Price

$87,460,932 x .0684 = $5,986,065

Expected Shareholder Returns Low Stock Price

$78,623,530 x .0735 = $5,776,618

Return on Book Equity 2006 High Stock Price

$5,986,065 / $50,633,040 = 11.82%

Return on Book Equity 2006 Low Stock Price

$5,776,618 / $50,633,040 = 11.41%

Data Source: The Value Line Investment Survey - Small and Mid-Cap Edition, December 15, 2006 and September 15, 2006

Exhibit MJB - 9
DCF Results for Delta Natural Gas Company
Using Average Growth Rate for Comapnies in the Value Line Survey

		Variable Name
2006 Annual Dividend	$1.20	D
High Price During 2006	$26.82	P
Low Price During 2006	$24.11	P
Average Growth Rate	3.67%	g
Shares Outstanding	3,261,034	
Earnings per Share in 2006	$1.55	
Book Equity	$ 50,633,040	

Company	Forecasted Dividend Growth Rate
AGL Resources, Inc.	6.5%
Atmos Energy Corp.	2.0%
Cascade Natural Gas Corp.	0.5%
Laclede Group	2.0%
New Jersey Resources, Inc.	4.5%
Northwest Natural Gas Company	4.0%
Piedmont Natural Gas Company	5.5%
South Jersey Industries, Inc.	6.0%
WGL Holdings,Inc.	2.0%
Average	**3.67%**

Using the DCF formula: ROE = D/P + g

ROE Based on the 2006 High Stock Price

ROE = (1.20 / 26.82) + .0367 = 8.14%

Market Capitalization 2006 High Stock Price

3,261,034 x 26.82 = $87,460,932

Expected Shareholder Returns High Stock Price

$87,460,932 x .0684 = $7,123,057

ROE Based on the 2006 Low Stock Price

ROE = (1.20 / 24.11) + .0367 = 8.65%

Market Capitalization 2006 Low Stock Price

3,261,034 x 24.11 = $78,623,530

Expected Shareholder Returns Low Stock Price

$78,623,530 x .0735 = $6,798,724

Return on Book Equity 2006 High Stock Price

$5,986,065 / $50,633,040 = 14.07%

Return on Book Equity 2006 Low Stock Price

$5,776,618 / $50,633,040 = 13.43%

Data Source: The Value Line Investment Survey - Small and Mid-Cap Edition, December 15, 2006 and September 15, 2006

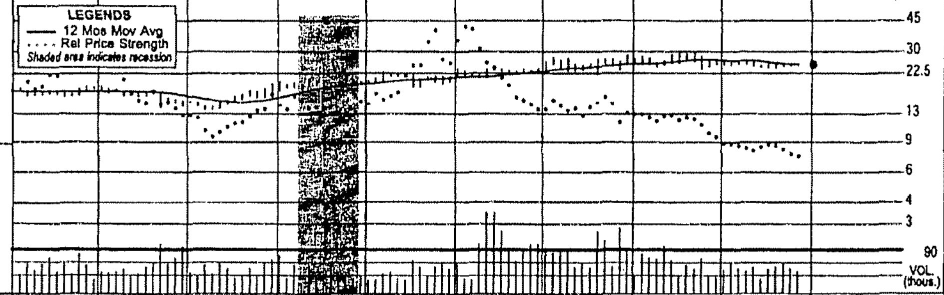
DELTA NAT. GAS NDQ–DGAS

RECENT PRICE 25.26 | TRAILING P/E RATIO 16.1 | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.8% | VALUE LINE

RANKS	19.25	19.00	19.62	20.99	23.08	24.10	28.75	30.00	26.82	High
	16.44	14.13	13.63	17.69	18.50	21.00	22.02	23.60	24.11	Low

PERFORMANCE 3 Average
Technical 2 Above Average
SAFETY 2 Above Average
BETA .55 (1.00 = Market)

Financial Strength B+
Price Stability 95
Price Growth Persistence 50
Earnings Predictability 65



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	18.64	16.02	18.68	28.36	22.11	21.59	24.74	26.06	36.01	
"CASH FLOW" PER SH	2.61	2.52	3.27	3.08	3.16	2.65	2.65	2.86	2.94	
EARNINGS PER SH	1.04	.90	1.42	1.47	1.45	1.49	1.20	1.55	1.55	*1.50[A,B]/1.50[C]*
DIV'DS DECL'D PER SH	1.14	1.14	1.14	1.14	1.16	1.18	1.18	1.18	1.20	
CAP'L SPENDING PER SH	4.71	3.31	3.58	2.83	3.72	2.90	2.80	1.65	2.39	
BOOK VALUE PER SH	12.55	12.39	12.73	13.12	13.51	14.49	15.26	15.73	16.16	
COMMON SHS OUTST'G (MILL)	2.38	2.41	2.46	2.50	2.53	3.17	3.20	3.23	3.26	
AVG ANN'L P/E RATIO	16.9	19.5	10.9	12.3	14.1	14.5	20.1	16.8	16.9	*16.8/16.8*
RELATIVE P/E RATIO	.88	1.11	.71	.63	.77	.83	1.06	.89	.91	
AVG ANN'L DIV'D YIELD	6.5%	6.5%	7.3%	6.3%	5.7%	5.5%	4.9%	4.5%	4.6%	
SALES ($MILL)	44.3	38.7	45.9	70.8	55.9	68.4	79.2	84.2	117.3	***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.***
OPERATING MARGIN	29.6%	34.0%	34.9%	23.2%	29.3%	24.7%	21.2%	21.9%	16.2%	
DEPRECIATION ($MILL)	3.8	3.9	4.6	4.0	4.4	4.5	4.7	4.3	4.6	
NET PROFIT ($MILL)	2.5	2.2	3.5	3.6	3.6	3.9	3.8	5.0	5.0	
INCOME TAX RATE	36.4%	36.6%	37.4%	38.0%	38.2%	38.0%	38.1%	38.3%	36.6%	
NET PROFIT MARGIN	5.5%	5.6%	7.5%	5.1%	6.5%	5.8%	4.8%	5.9%	4.3%	
WORKING CAP'L ($MILL)	d5.2	d9.3	d12.3	d12.6	d15.3	d.2	d.7	.9	4.6	
LONG-TERM DEBT ($MILL)	52.6	51.7	50.7	49.3	48.6	53.4	53.0	52.7	58.8	
SHR. EQUITY ($MILL)	29.8	29.9	31.3	32.8	34.2	45.9	48.8	50.8	52.6	
RETURN ON TOTAL CAP'L	5.0%	5.0%	6.6%	6.7%	6.6%	5.9%	5.6%	6.7%	6.7%	
RETURN ON SHR. EQUITY	8.2%	7.2%	11.1%	11.1%	10.6%	8.6%	7.9%	9.8%	9.5%	
RETAINED TO COM EQ	NMF	NMF	2.2%	2.5%	2.1%	1.6%	.2%	2.4%	2.1%	
ALL DIV'DS TO NET PROF	110%	NMF	80%	78%	80%	81%	98%	76%	77%	

[A]No. of analysts changing earn. est. in last 2 days: 0 up, 0 down, consensus 5-year earnings growth 2.0% per year. [B]Based upon 2 analysts' estimates. [C]Based upon one analyst's estimate.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	6.5%	38.0%
"Cash Flow"	-1.0%	2.5%
Earnings	2.5%	--
Dividends	1.0%	1.5%
Book Value	4.5%	2.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
06/30/04	10.1	16.8	35.7	16.6	79.2
06/30/05	9.8	25.8	33.4	15.2	84.2
06/30/06	14.2	42.1	46.5	14.5	117.3
06/30/07	13.1				

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
06/30/03	d.36	.27	1.66	d.08	1.49
06/30/04	d.28	.13	1.19	.16	1.20
06/30/05	d.35	.87	1.16	d.13	1.55
06/30/06	d.18	.89	1.03	d.19	1.55
06/30/07	d.16	*.70*	*1.12*	*d.17*	

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.295	.295	.295	.295	1.18
2004	.295	.295	.295	.295	1.18
2005	.295	.295	.30	.30	1.19
2006	.30	.30	.305	.305	1.21

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	7	5	8
to Sell	3	3	3
Hld's(000)	283	284	324

ASSETS ($mill.)	2005	2006	9/30/06
Cash Assets	.1	.2	.2
Receivables	6.6	7.9	7.3
Inventory (Avg cost)	10.2	11.8	17.8
Other	3.6	3.6	3.7
Current Assets	20.5	23.5	29.0
Property, Plant & Equip, at cost	174.7	182.2	--
Accum Depreciation	58.2	61.8	--
Net Property	116.5	120.4	120.8
Other	7.8	11.7	11.5
Total Assets	144.8	155.6	161.3
LIABILITIES ($mill.)			
Accts Payable	7.4	6.4	6.0
Debt Due	7.6	8.3	15.8
Other	4.6	4.2	4.2
Current Liab	19.6	18.9	26.0

LONG-TERM DEBT AND EQUITY as of 9/30/06

Total Debt $74.6 mill. **Due in 5 Yrs.** NA
LT Debt $58.8 mill.
Including Cap. Leases NA
(53% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '06 vs. None in '05

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 3,261,034 shares
(47% of Cap'l)

INDUSTRY: Natural Gas (Div.)

BUSINESS: Delta Natural Gas Company, Inc. sells natural gas to retail customers on its distribution system in central and southeastern Kentucky. As of March 31, the company sold natural gas to approximately 39,000 retail customers on its distribution system. It also transports natural gas to its industrial customers, who purchase their gas in the open market. In addition, Delta Natural transports natural gas on behalf of local producers and customers not on its distribution system. Delta Natural Gas serves residential, commercial, and industrial customers in the areas of Nicholasville, Corbin, and Berea, Kentucky. As of the above date, the company served approximately 8,000 customers in Nicholasville, approximately 6,000 in Corbin, and approximately 4,000 in Berea. Has 156 employees. Chairman: Harrison D. Peet. Inc.: KY. Address: 3617 Lexington Road, Winchester, KY 40391. Tel.: (859) 744-6171. Internet: http://www.deltagas.com.

L.Y.

December 15, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 11/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
2.01%	5.46%	4.11%	24.75%	60.02%

St Louis Fed | Economic Research | EconDISC | ALFRED® | CASSIDI™ | FRASER® | Liber8™ | Federal Reserve System Help

ECONOMIC RESEARCH
FEDERAL RESERVE BANK of ST. LOUIS
Advancing Economic Knowledge Through Research & Data

RSS | Email Notifications | Data Lists | My Account | Log In

Publications | Economic Data - FRED® | Working Papers | Economists | Conferences | CRE8™

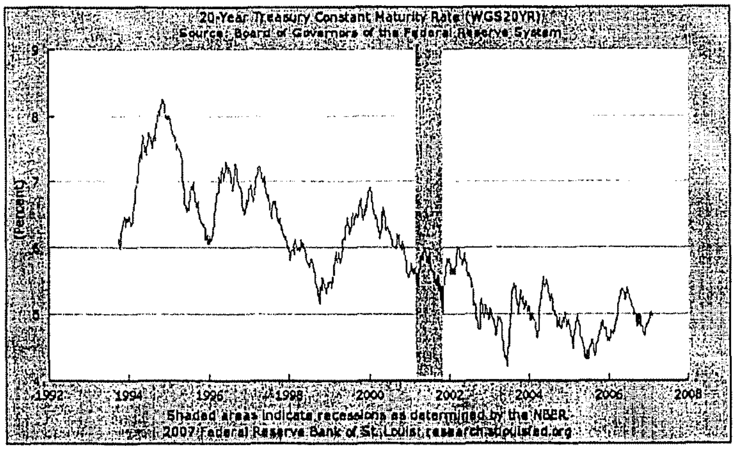
Economic Data - FRED Search

Employment | Seminars | Monetary Aggregates

Home > Economic Data - FRED® > Categories > Interest Rates > Series: WGS20YR, 20-Year Treasury Constant Maturity Rate

Series: WGS20YR, 20-Year Treasury Constant Maturity Rate

View Data | Download Data | Notify Me of Updates | Add to My Data List | Vintage Series in ALFRED



Format: Linear

Range: 5yrs | 10yrs | Max **Recession Bars:** On | Off **Size:** Medium | Large

Custom Range: 1993-10-01 to 2007-02-09 **Plot vs:** <Enter Series ID> Same Scale

Go

Latest Observations:

Date	2007-01-12	2007-01-19	2007-01-26	2007-02-02	2007-02-09
Value	4.88	4.96	5.01	5.04	4.96

Series Properties:

Series ID:	WGS20YR
Source(s):	Board of Governors of the Federal Reserve System
Release:	H.15 Selected Interest Rates
Units:	Percent
Frequency:	Weekly, Ending Friday
Seasonal Adjustment:	Not Applicable
Observation Range:	1993-10-01 to 2007-02-09
Last Updated:	2007-02-13
Notes:	Averages of business days. For further information regarding treasury constant maturity data, please refer to http://www.federalreserve.gov/releases/h15/current/h15.pdf and http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html
Other Formats:	Daily Monthly

Related Categories:

U.S. Financial Data > Interest Rates
Interest Rates > Treasury Constant Maturity

About | Contact Us | Privacy | Legal Top of Page

Exhibit MJB - 12
Results of the CAPM Analysis
Delta Natural Gas Company

		Variable Name	Data Source
20 - Year U. S. Treasury Bond Yield	5.0%	**Rf**	1
Long - Horizon Expected Equity Risk Premium for Large Companies	7.1%	**Rm - Rf**	2
Calculated Beta Coefficient for Delta Natural Gas	0.55	**B**	3
Micro-Cap Size Premium for Delta	9.83%		

Using the CAPM Formula: ROE = Rf + B (Rm - Rf)

<u>CAPM Calculation</u>

Initial ROE Estimate = 0.05 + 0.55 (0.071) =	8.9050%
Size premium adjustment for Delta for CAPM calculations	9.83%
ROE Estimate Including Micro-Cap Size Premium =	18.7350%

Data Sources:

1. Yield for 20-Year Treasury Constant Maturity Rate,
   Federal Reserve Bank of St. Louis Economic Research

2. <u>Risk Premium Over Time Report : 2006</u>, Ibbotson Associates, 2006

3. <u>The Value Line Investment Survey - Small and Mid-Cap Edition</u>, Dec. 15, 2006

Exhibit MJB - 13
Results of the Risk Premium Analysis
Delta Natural Gas Company

		Data Source
20 - Year U. S. Treasury Bond Yield	5.0%	1
Long - Horizon Expected Equity Risk Premium for Large Companies	7.1%	2

Risk Premium Calculation

ROE = 0.05 + 0.071 = 12.1%

Data Sources:

1. 20-Year Treasury Constant Maturity, Federal Reserve Economic Data (FRED), Federal Reserve Bank of St. Louis

2. Risk Premium Over Time Report : 2006, Ibbotson Associates, 2006, p. 6

Exhibit MJB-14
Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies
Using Sustainable Growth Rates for Small and Mid Cap Companies

Company	Beta	Dividend	Growth Rate	High Stock Price	Low Stock Price	Size Premium	DCF Low Stock Price	DCF High Stock Price	CAPM
Data Source	**1**	**1**	**1**	**1**	**1**	**2**			
AGL Resources, Inc.	0.95	$ 1.50	6.50%	$ 40.00	$ 34.40	1.10%	10.86%	10.25%	13.04%
Cascade Natural Gas Corp.	0.85	$ 0.96	0.50%	$ 26.30	$ 19.00	2.76%	5.55%	4.15%	13.98%
Laclede Group	0.85	$ 1.40	2.00%	$ 37.51	$ 29.10	2.33%	6.81%	5.73%	13.55%
Peoples Energy Corp.	0.85	$ 2.18	0.00%	$ 45.21	$ 34.90	1.73%	6.25%	4.82%	12.95%
New Jersey Resources, Inc.	0.80	$ 1.45	4.50%	$ 53.16	$ 41.50	1.67%	7.99%	7.23%	12.53%
Piedmont Natural Gas Company	0.80	$ 0.96	5.50%	$ 28.44	$ 23.20	1.73%	9.64%	8.88%	12.59%
WGL Holdings,Inc.	0.80	$ 1.35	2.00%	$ 33.55	$ 27.00	1.73%	7.00%	6.02%	12.59%
Atmos Energy Corp.	0.75	$ 1.26	2.00%	$ 29.30	$ 25.50	0.85%	6.94%	6.30%	11.35%
Northwest Natural Gas Company	0.75	$ 1.38	4.00%	$ 43.69	$ 32.80	1.67%	8.21%	7.16%	12.17%
South Jersey Industries, Inc.	0.70	$ 0.92	6.00%	$ 34.26	$ 25.60	2.33%	9.59%	8.69%	12.47%
EnergySouth, Inc.	0.60	$ 0.92	6.48%	$ 41.53	$ 26.40	4.39%	9.96%	8.70%	13.81%
Delta Natural Gas Company	**0.55**	**$ 1.20**	**2.37%**	**$ 26.82**	**$ 24.11**	**9.83%**	**7.35%**	**6.84%**	**18.89%**
RGC Resources, Inc.	0.40	$ 1.22	2.70%	$ 28.14	$ 22.72	9.83%	8.07%	7.04%	17.81%
Energy West	0.35	$ 0.48	3.18%	$ 12.00	$ 8.57	9.83%	8.78%	7.18%	17.45%
						Mean	8.07%	7.07%	13.94%
						Median	8.03%	7.10%	13.00%

Data Sources:

1. The Value Line Investment Survey - Sep. 15, 2006
2. Risk Premium Over Time Report : 2006, Ibbotson Associates, 2006

Exhibit MJB-14
Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies
Using Sustainable Growth Rates for Small and Mid Cap Companies

Company	Shares	Market Equity High Stock Price	Market Equity Low Stock Price	Dollar Return High Stock Price	Dollar Return Low Stock Price
Data Source	**1**				
AGL Resources, Inc.	77,878,889	$ 3,115,155,560	$ 2,679,033,782	$ 319,303,445	$ 290,955,529
Cascade Natural Gas Corp.	11,505,996	$ 302,607,695	$ 218,613,924	$ 12,558,795	$ 12,138,826
Laclede Group	21,357,000	$ 801,101,070	$ 621,488,700	$ 45,921,821	$ 42,329,574
Peoples Energy Corp.	38,471,441	$ 1,739,293,848	$ 1,342,653,291	$ 83,867,741	$ 83,867,741
New Jersey Resources, Inc.	28,080,314	$ 1,492,749,492	$ 1,165,333,031	$ 107,890,182	$ 93,156,442
Piedmont Natural Gas Company	75,277,250	$ 2,140,884,990	$ 1,746,432,200	$ 190,014,834	$ 168,319,931
WGL Holdings,Inc.	48,773,729	$ 1,636,358,608	$ 1,316,890,683	$ 98,571,706	$ 92,182,348
Atmos Energy Corp.	81,595,723	$ 2,390,754,684	$ 2,080,690,937	$ 150,625,705	$ 144,424,430
Northwest Natural Gas Company	27,548,346	$ 1,203,587,237	$ 903,585,749	$ 86,160,207	$ 74,160,147
South Jersey Industries, Inc.	29,232,801	$ 1,001,515,762	$ 748,359,706	$ 86,985,123	$ 71,795,759
EnergySouth, Inc.	7,936,000	$ 329,582,080	$ 209,510,400	$ 28,658,039	$ 20,877,394
Delta Natural Gas Company	**3,261,034**	**$ 87,460,932**	**$ 78,623,530**	**$ 5,986,065**	**$ 5,776,618**
RGC Resources, Inc.	2,130,573	$ 59,954,324	$ 48,406,619	$ 4,218,066	$ 3,906,278
Energy West	2,931,158	$ 35,173,896	$ 25,120,024	$ 2,525,486	$ 2,205,773

Data Sources:

1. The Value Line Investment Survey - Se|
2. Risk Premium Over Time Report : 2006

Exhibit MJB-14
Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies
Using Sustainable Growth Rates for Small and Mid Cap Companies

Company	Book Equity	Return on Book Equity High Stock Price	Return on Book Equity Low Stock Price
Data Source	1		
AGL Resources, Inc.	$ 1,593,480,000	20.04%	18.26%
Cascade Natural Gas Corp.	$ 123,517,500	10.17%	9.83%
Laclede Group	$ 399,432,500	11.50%	10.60%
Peoples Energy Corp.	$ 833,354,880	10.06%	10.06%
New Jersey Resources, Inc.	$ 620,096,100	17.40%	15.02%
Piedmont Natural Gas Company	$ 898,050,920	21.16%	18.74%
WGL Holdings,Inc.	$ 927,208,800	10.63%	9.94%
Atmos Energy Corp.	$ 1,646,237,800	9.15%	8.77%
Northwest Natural Gas Company	$ 596,443,650	14.45%	12.43%
South Jersey Industries, Inc.	$ 435,155,050	19.99%	16.50%
EnergySouth, Inc.	$ 111,064,550	25.80%	18.80%
Delta Natural Gas Company	**$ 51,697,650**	**11.58%**	**11.17%**
RGC Resources, Inc.	$ 40,182,150	10.50%	9.72%
Energy West	$ 18,863,520	13.39%	11.69%
	Mean	14.70%	12.97%
	Median	12.48%	11.43%

Data Sources:

1. The Value Line Investment Survey - Se
2. Risk Premium Over Time Report : 2006

Exhibit MJB - 15

Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies Using Average Growth Rates For Small and Mid Cap Companies

Company	Beta	Dividend	Growth Rate	High Stock Price	Low Stock Price	Size Premium	DCF Low Stock Price	DCF High Stock Price	CAPM
Data Source	**1**	**1**	**1**	**1**	**1**	**2**			
AGL Resources, Inc.	0.95	$ 1.50	6.50%	$ 40.00	$ 34.40	1.10%	10.86%	10.25%	13.04%
Atmos Energy Corp.	0.75	$ 1.26	2.00%	$ 29.30	$ 25.50	0.85%	6.94%	6.30%	11.35%
Cascade Natural Gas Corp.	0.85	$ 0.96	0.50%	$ 26.30	$ 19.00	2.76%	5.55%	4.15%	13.98%
Delta Natural Gas Company	**0.55**	**$ 1.20**	**3.67%**	**$ 26.82**	**$ 24.11**	**9.83%**	**8.64%**	**8.14%**	**18.89%**
Energy West	0.35	$ 0.48	3.67%	$ 12.00	$ 8.57	9.83%	9.27%	7.67%	17.45%
EnergySouth, Inc.	0.60	$ 0.92	3.67%	$ 41.53	$ 26.40	4.39%	7.15%	5.88%	13.81%
Laclede Group	0.85	$ 1.40	2.00%	$ 37.51	$ 29.10	2.33%	6.81%	5.73%	13.55%
New Jersey Resources, Inc.	0.80	$ 1.45	4.50%	$ 53.16	$ 41.50	1.67%	7.99%	7.23%	12.53%
Northwest Natural Gas Company	0.75	$ 1.38	4.00%	$ 43.69	$ 32.80	1.67%	8.21%	7.16%	12.17%
Peoples Energy Corp.	0.85	$ 2.18	0.00%	$ 45.21	$ 34.90	1.73%	6.25%	4.82%	12.95%
Piedmont Natural Gas Company	0.80	$ 0.96	5.50%	$ 28.44	$ 23.20	1.73%	9.64%	8.88%	12.59%
RGC Resources, Inc.	0.40	$ 1.22	3.67%	$ 28.14	$ 22.72	9.83%	9.04%	8.00%	17.81%
South Jersey Industries, Inc.	0.70	$ 0.92	6.00%	$ 34.26	$ 25.60	2.33%	9.59%	8.69%	12.47%
WGL Holdings,Inc.	0.80	$ 1.35	2.00%	$ 33.55	$ 27.00	1.73%	7.00%	6.02%	12.59%
						Mean	8.07%	7.07%	13.94%
						Median	8.10%	7.19%	13.00%
		Avg of 9	3.67%						

Data Sources:

1. The Value Line Investment Survey - Sep. 15, 2006
2. Risk Premium Over Time Report : 2006, Ibbotson Associates, 2006

Exhibit MJB - 15

Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies
Using Average Growth Rates For Small and Mid Cap Companies

Company	Shares	Market Equity High Stock Price	Market Equity Low Stock Price	Dollar Return High Stock Price	Dollar Return Low Stock Price
Data Source	**1**				
AGL Resources, Inc.	77,878,889	$ 3,115,155,560	$ 2,679,033,782	$ 319,303,445	$ 290,955,529
Atmos Energy Corp.	81,595,723	$ 2,390,754,684	$ 2,080,690,937	$ 150,625,705	$ 144,424,430
Cascade Natural Gas Corp.	11,505,996	$ 302,607,695	$ 218,613,924	$ 12,558,795	$ 12,138,826
Delta Natural Gas Company	**3,261,034**	**$ 87,460,932**	**$ 78,623,530**	**$ 7,120,142**	**$ 6,796,104**
Energy West	2,931,158	$ 35,173,896	$ 25,120,024	$ 2,696,665	$ 2,328,023
EnergySouth, Inc.	7,936,000	$ 329,582,080	$ 209,510,400	$ 19,385,796	$ 14,983,168
Laclede Group	21,357,000	$ 801,101,070	$ 621,488,700	$ 45,921,821	$ 42,329,574
New Jersey Resources, Inc.	28,080,314	$ 1,492,749,492	$ 1,165,333,031	$ 107,890,182	$ 93,156,442
Northwest Natural Gas Company	27,548,346	$ 1,203,587,237	$ 903,585,749	$ 86,160,207	$ 74,160,147
Peoples Energy Corp.	38,471,441	$ 1,739,293,848	$ 1,342,653,291	$ 83,867,741	$ 83,867,741
Piedmont Natural Gas Company	75,277,250	$ 2,140,884,990	$ 1,746,432,200	$ 190,014,834	$ 168,319,931
RGC Resources, Inc.	2,130,573	$ 59,954,324	$ 48,406,619	$ 4,797,624	$ 4,374,208
South Jersey Industries, Inc.	29,232,801	$ 1,001,515,762	$ 748,359,706	$ 86,985,123	$ 71,795,759
WGL Holdings,Inc.	48,773,729	$ 1,636,358,608	$ 1,316,890,683	$ 98,571,706	$ 92,182,348

Data Sources:

1. The Value Line Investment Survey - Se
2. Risk Premium Over Time Report : 200(

Exhibit MJB - 15

Estimated Return on Equity for Edward Jones Panel of Natural Gas Distribution Companies Using Average Growth Rates For Small and Mid Cap Companies

Company	Book Equity	Return on Book Equity High Stock Price	Return on Book Equity Low Stock Price
Data Source	1		
AGL Resources, Inc.	$ 1,593,480,000	20.04%	18.26%
Atmos Energy Corp.	$ 1,646,237,800	9.15%	8.77%
Cascade Natural Gas Corp.	$ 123,517,500	10.17%	9.83%
Delta Natural Gas Company	**$ 51,697,650**	**13.77%**	**13.15%**
Energy West	$ 18,863,520	14.30%	12.34%
EnergySouth, Inc.	$ 111,064,550	17.45%	13.49%
Laclede Group	$ 399,432,500	11.50%	10.60%
New Jersey Resources, Inc.	$ 620,096,100	17.40%	15.02%
Northwest Natural Gas Company	$ 596,443,650	14.45%	12.43%
Peoples Energy Corp.	$ 833,354,880	10.06%	10.06%
Piedmont Natural Gas Company	$ 898,050,920	21.16%	18.74%
RGC Resources, Inc.	$ 40,182,150	11.94%	10.89%
South Jersey Industries, Inc.	$ 435,155,050	19.99%	16.50%
WGL Holdings,Inc.	$ 927,208,800	10.63%	9.94%
	Mean	14.43%	12.86%
	Median	14.03%	12.39%

Data Sources:

1. The Value Line Investment Survey - Se
2. Risk Premium Over Time Report : 200(

AGL RESOURCES NYSE-ATG

RECENT PRICE 35.97 | P/E RATIO 14.2 (Trailing: 13.3 / Median: 14.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 4.2% | VALUE LINE

High:	20.0	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.0
Low:	14.9	17.1	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4

TIMELINESS 4 Lowered 8/11/06
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 9/1/06
BETA .95 (1.00 = Market)

2009-11 PROJECTIONS

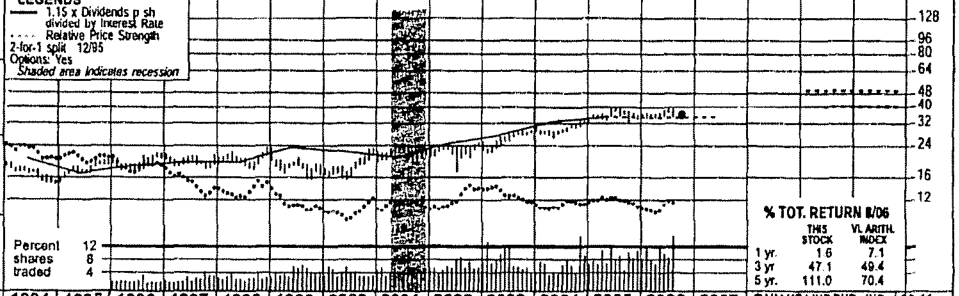
	Price	Gain	Ann'l Total Return
High	50	(+40%)	12%
Low	40	(+10%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	1	0	1	1	0	0	0
to Sell	1	1	1	0	0	1	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	109	110	95
to Sell	88	83	102
Hld's(000)	49186	45106	49525



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.6	7.1
3 yr.	47.1	49.4
5 yr.	111.0	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
22.58	20.26	20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	35.55	36.10	Revenues per sh A	38.45
2.04	2.07	2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.40	4.50	"Cash Flow" per sh	4.85
1.01	1.04	1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.65	2.70	Earnings per sh A B	2.95
.98	1.02	1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.50	1.58	Div'ds Decl'd per sh C■	1.75
2.73	2.95	2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	2.80	3.10	Cap'l Spending per sh	2.25
8.97	9.42	9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.40	21.50	Book Value per sh D	24.90
44.32	47.57	48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.90	78.00	Common Shs Outst'g E	78.30
14.2	15.3	15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	Bold figures are	Value Line	Avg Ann'l P/E Ratio	15.0
1.05	.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	estimates		Relative P/E Ratio	1.00
6.8%	6.4%	5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.8%	4.7%	4.3%	3.9%	3.7%			Avg Ann'l Div'd Yield	4.0%
						1220.2	1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2770	2815	Revenues ($mill) A	3010
						75.6	76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	205	210	Net Profit ($mill)	230
						38.6%	37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	38.0%	38.0%	Income Tax Rate	38.0%
						6.2%	5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	7.5%	7.5%	Net Profit Margin	7.7%
						46.2%	48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	51.0%	50.0%	Long-Term Debt Ratio	48.5%
						48.9%	45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.0%	50.0%	Common Equity Ratio	51.5%
						1201.3	1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3225	3310	Total Capital ($mill)	3775
						1415.4	1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3350	3450	Net Plant ($mill)	3750
						8.0%	7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	8.0%	Return on Total Cap'l	7.5%
						11.7%	11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.0%	12.5%	Return on Shr. Equity	12.0%
						12.1%	11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.0%	12.5%	Return on Com Equity	12.0%
						3.8%	3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	5.5%	5.5%	Retained to Com Eq	5.0%
						71%	74%	64%	101%	72%	65%	52%	53%	49%	52%	57%	58%	All Div'ds to Net Prof	59%

CAPITAL STRUCTURE as of 6/30/06
Total Debt 2087.0 mill. Due in 5 Yrs $530.0 mill.
LT Debt $1632.0 mill. LT Interest $100.0 mill.

(Total interest coverage: 4.4x)
Leases, Uncapitalized Annual rentals $27.0 mill.

Pension Assets-12/05 $371.0 mill. **Oblig.** $464.0 mill.

Pfd Stock None
Common Stock 77,878,889 shs. as of 7/31/06

MARKET CAP: $2.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	49.0	30.0	37.0
Other	1408.0	2002.0	1471.0
Current Assets	1457.0	2032.0	1508.0
Accts Payable	207.0	264.0	566.0
Debt Due	334.0	522.0	455.0
Other	936.0	1153.0	329.0
Current Liab.	1477.0	1939.0	1350.0
Fix. Chg. Cov.	510%	442%	470%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	1.0%	7.0%	7.5%
"Cash Flow"	5.0%	7.0%	5.0%
Earnings	6.5%	13.5%	4.5%
Dividends	1.5%	2.0%	6.5%
Book Value	5.5%	8.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	352.5	186.6	166.3	278.3	983.7
2004	651.0	294.0	262.0	625.0	1832.0
2005	908.0	430.0	387.0	993.0	2718.0
2006	1047.0	436.0	405	882	2770
2007	970	480	465	900	2815

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.98	.29	.27	.54	2.08
2004	1.00	.33	.31	.64	2.28
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.27	.72	2.65
2007	1.30	.37	.29	.74	2.70

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.27	.27	.27	.27	1.08
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37		

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries are Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia (primarily Atlanta), Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acq. Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common; Goldman Sachs, 5.5%; JPMorgan, 5.9% (3/06 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: 10 Peachtree Place N.E., Atlanta, GA 30309. Tel.: 404-584-4000. Internet: www.aglresources.com.

AGL Resources utility business performed well despite warmer-than-normal temperatures and conservation by customers. Earnings before interest and taxes increased $7 million versus the year-ago period, driven by a $6 million decrease in operating expenses. This can be attributed to last year's workforce and facilities restructuring programs. Also, operation and maintenance expenses per customer throughout AGL's distribution segment decreased 9% over the first six months of 2006. However, these results were offset by a lackluster performance at SouthStar, which markets natural gas and related services to retail customers on an unregulated basis, where results were also impacted by lower customer usage and higher bad debt expense.

Virginia Natural Gas (VNG) has accepted a modified performance-based rate plan. As part of the deal, VNG will freeze its base rates for five years; construct a pipeline to connect its northern and southern systems, which is expected to cost about $48 million to $60 million; and will be allowed to file for a permanent weather normalization plan. Also, Chattanooga Gas filed for a $5.8 million rate increase with the Tennessee Regulatory Authority to cover rising costs of financing its operations and lower consumption of natural gas. The proposal includes a plan to better align its interest with customers, by adjusting rates annually based on actual consumption versus an assumed level. We think Chattanooga will receive some, if not all, of the rate increase, which should provide a boost to earnings.

AGL's expansion of its Jefferson Island storage facility has hit a road block. In early August, the Louisiana Department of Natural Resources terminated the company's mineral lease due to the timing of leasehold payments and a lack of mining activity on the site for six months. Even so, the company remains committed to resolving these issues and getting the project completed, which will increase working gas capacity, along with revenues.

This neutrally ranked stock has worthwhile total return potential, thanks partly to dividend growth prospects. The good-quality shares are safe and steady, but not overly enticing.

Evan I. Blatter *September 15, 2006*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, d$0.83; '99, $0.39; '00, $0.13; '01, $0.13; '03, d$0.07. Next earnings report due late Oct.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2005: $422 million, $5.43/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

ATMOS ENERGY CORP. NYSE-ATO

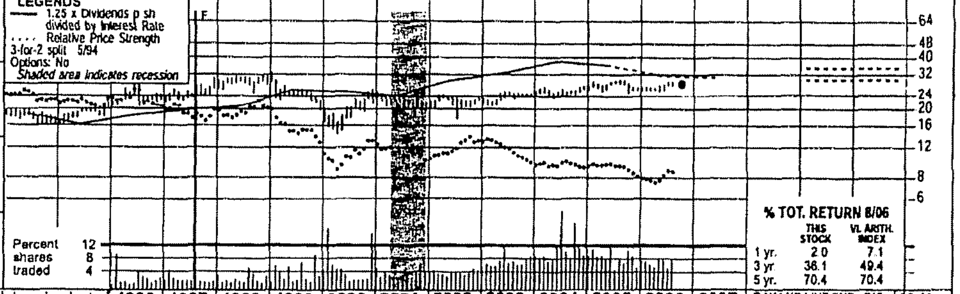
RECENT PRICE **28.36** | P/E RATIO **15.6** (Trailing: 18.3) (Median: 16.0) | RELATIVE P/E RATIO **0.92** | DIV'D YLD **4.5%** | VALUE LINE

TIMELINESS **3** Raised 7/28/06
SAFETY **2** Raised 12/16/05
TECHNICAL **2** Raised 8/18/06
BETA .75 (1.00 = Market)

High:	23.0	31.0	30.5	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	29.3
Low:	16.1	20.9	22.1	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 5/94
Options: No
Shaded area indicates recession

Target Price Range 2009 | 2010 | 2011



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	10%
Low	30	(+5%)	6%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	1	0	1	0	0	0	1	0	1

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	93	89	102
to Sell	91	84	67
Hld's(000)	43022	46004	46293

Percent shares traded 12 8 4

% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	2.0	7.1
3 yr.	36.1	49.4
5 yr.	70.4	70.4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
30.19	30.59	27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	*76.60*	*79.75*	Revenues per sh A	*105.00*
2.80	2.85	3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	*4.05*	*4.30*	"Cash Flow" per sh	*5.30*
1.51	1.34	1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	*1.80*	*1.95*	Earnings per sh A B	*2.50*
.96	1.01	1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	*1.26*	*1.28*	Div'ds Decl'd per sh C ■	*1.35*
4.84	4.13	4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	*5.00*	*5.90*	Cap'l Spending per sh	*7.30*
10.75	11.04	12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	*20.45*	*21.50*	Book Value per sh	*24.10*
16.02	29.64	30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	*82.00*	*84.00*	Common Shs Outst'g D	*100.00*
15.1	17.9	15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.0*
.95	1.03	.80	1.88	1.23	.80	.83	.76	.84	.84	*estimates*		Relative P/E Ratio	*.85*
4.2%	4.2%	3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%			Avg Ann'l Div'd Yield	*4.2%*
483.7	906.8	848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	*6280*	*6700*	Revenues ($mill) A	*10500*
23.9	39.2	55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	*150*	*165*	Net Profit ($mill)	*250*
35.7%	37.5%	36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	*37.5%*	*37.5%*	Income Tax Rate	*38.0%*
5.0%	4.3%	6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	*2.4%*	*2.5%*	Net Profit Margin	*2.3%*
41.5%	48.1%	51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	*57.0%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
58.5%	51.9%	48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	*43.0%*	*43.0%*	Common Equity Ratio	*45.0%*
294.6	630.2	769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	*3900*	*4200*	Total Capital ($mill)	*5350*
413.6	849.1	917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	*3675*	*3975*	Net Plant ($mill)	*5000*
10.6%	8.3%	9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.5%*
13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	*9.0%*	*9.0%*	Return on Com Equity	*10.5%*
5.1%	3.9%	6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	*3.0%*	*3.0%*	Retained to Com Eq	*5.0%*
64%	67%	58%	NMF	112%	79%	82%	70%	77%	73%	*69%*	*65%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $2481.2 mill. Due in 5 Yrs $860.0 mill.
LT Debt $2180.8 mill. LT Interest $135.0 mill.
(LT interest earned: 2.7x; total interest coverage: 2.6x)
Leases, Uncapitalized Annual rentals $15.3 mill.
Pfd Stock None
Pension Assets-9/05 $355.9 mill. **Oblig.** $359.9 mill.
Common Stock 81,595,723 shs.
as of 7/31/06
MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	201.9	40.1	26.8
Other	475.2	1224.3	1023.4
Current Assets	677.1	1264.4	1050.2
Accts Payable	185.3	461.3	306.8
Debt Due	5.9	148.1	300.4
Other	223.3	503.4	407.6
Current Liab.	414.5	1112.8	1014.8
Fix. Chg. Cov.	384%	395%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	6.0%	16.5%	*11.5%*
"Cash Flow"	3.5%	2.0%	*8.0%*
Earnings	4.0%	6.5%	*7.0%*
Dividends	3.0%	2.0%	*2.0%*
Book Value	6.5%	8.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	680.4	1194.1	488.5	436.9	2799.9
2004	763.6	1117.5	546.1	492.8	2920.0
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	*1099.2*	*6280*
2007	*1675*	*1675*	*1675*	*1675*	*6700*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.60	1.24	--	d.05	1.71
2004	.57	1.12	.09	d.11	1.58
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	*.04*	*1.80*
2007	*.85*	*1.15*	*.08*	*d.13*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.295	.295	.295	.30	1.19
2003	.30	.30	.30	.305	1.21
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315		

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via seven regulated natural gas utility operations: Louisiana Division, Mid-States Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky Division. Combined 2005 gas volumes: 296 MMcf. Breakdown: 55%, residential; 31%, commercial; 10%, industrial; and 4% other. 2005 depreciation rate 3.7%. Has around 4,330 employees. Officers and directors own approximately 2.6% of common stock (12/05 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

It appears that Atmos Energy's earnings per share increased around 5%, to $1.80, in fiscal 2006 (ends September 30th). Within the non-utility division, the marketing segment benefited greatly from strategies to capture favorable arbitrage spreads created by natural gas volatility. But the performance of the utility operation was hampered by warmer temperatures, which especially affected the Mid-Tex and Louisiana units because they did not have a weather-normalized rate structure during that time. (Combined, these units account for over 60% of the customer base.) Also, we estimate that the after-effects of Hurricane Katrina reduced share net by about $0.10.

We believe that the bottom line will advance about 8%, to $1.95 a share, in fiscal 2007, assuming further expansion in operating margins. And it is important to note that weather-normalized rates will be effective for the Mid-Tex operation beginning October 1st. Moreover, a rate design calling for a partial decoupling from the impact of unfavorable temperatures will take effect for the Louisiana unit on December 1st. With these moves, some 90% of the utility's margins are protected by weather-normalization adjustments (versus about 33% previously).

Atmos looks poised to register steady, if measured, bottom-line increases over the 2009-2011 period. With the utility division now serving 3.2 million customers across 12 states, the company is not dependent on the economic climate in any one region of the country. Furthermore, the non-utility segments, particularly pipelines, have decent expansion prospects. In the present corporate configuration, share net ought to grow around 8% annually over the 3- to 5-year horizon.

These good-quality shares offer a healthy dose of dividend income. Prospects for additional increases in the distribution seem reasonable, too, as supported by our favorable 2009-2011 projections for Atmos Energy.

But long-term total-return potential is not spectacular, as capital appreciation possibilities are limited at the current quotation. Also, the equity is ranked to perform only in line with the market in the year ahead.

Frederick L. Harris, III September 15, 2006

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '97, d53¢; '99, d23¢; '00, 12¢; '03, d17¢. Next egs. rpt. due early Nov. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	85

CASCADE NAT'L GAS NYSE-CGC

RECENT PRICE **25.55** | P/E RATIO **23.2** (Trailing: 23.0 / Median: 18.0) | RELATIVE P/E RATIO **1.36** | DIV'D YLD **3.8%** | **VALUE LINE**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	17.5	17.5	19.0	18.7	19.8	20.9	22.8	24.2	22.0	23.0	22.8	26.3	
Low:	13.0	13.4	15.3	14.6	14.4	13.4	17.4	15.5	18.0	19.1	18.0	19.0	

Target Price Range: 2009 | 2010 | 2011

TIMELINESS — Suspended 7/21/06
SAFETY 3 New 7/27/90
TECHNICAL — Suspended 7/21/06
BETA .85 (1.00 = Market)

2009-11 PROJECTIONS

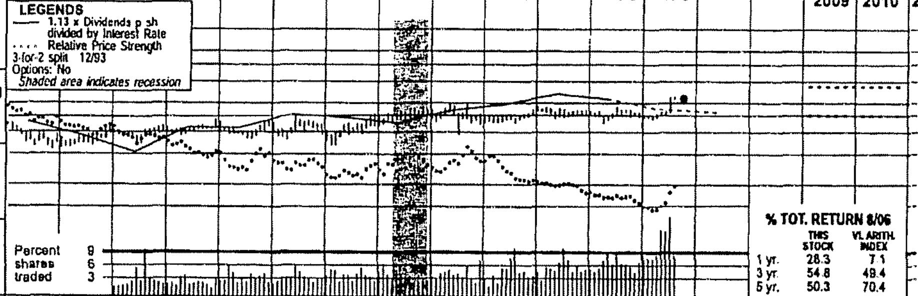
	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-20%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	38	47	53
to Sell	34	31	28
Hld's(000)	4695	4911	5297



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	28.3	7.1
3 yr.	54.8	49.4
5 yr.	50.3	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
24.45	23.27	20.03	21.88	21.59	19.98	11.84	17.85	17.17	18.89	21.90	30.40	29.06	27.20	28.23	28.61	*40.45*	*44.80*	Revenues per sh A	*64.00*
2.36	2.29	1.66	2.04	1.71	2.07	1.22	1.92	2.06	2.40	2.60	2.72	2.48	2.25	2.63	2.32	*2.65*	*2.85*	"Cash Flow" per sh	*4.00*
1.26	1.14	.63	1.05	.60	.80	.39	.93	.84	1.24	1.39	1.47	1.13	.87	1.19	.82	*1.10*	*1.20*	Earnings per sh AB	*1.60*
.87	.90	.93	.94	.96	.96	.72	.96	.96	.96	.96	.96	.96	.96	.96	.96	*.96*	*.96*	Div'ds Decl'd per sh C■	*.98*
2.50	2.97	4.64	3.85	3.06	4.12	2.42	2.66	2.32	1.81	1.65	2.16	1.91	2.56	3.50	2.53	*1.90*	*2.20*	Cap'l Spending per sh	*4.10*
8.33	8.63	9.09	9.96	9.81	9.76	10.09	10.16	10.07	10.36	10.79	11.01	10.34	10.11	10.52	10.39	*11.65*	*13.30*	Book Value per sh D	*18.05*
6.56	6.63	7.61	8.57	8.91	9.14	10.79	10.97	11.05	11.05	11.05	11.05	11.05	11.13	11.27	11.41	*11.50*	*11.50*	Common Shs Outst'g E	*12.50*
8.9	12.2	23.7	16.6	25.7	18.2	40.0	17.6	19.4	13.7	11.7	13.4	18.2	22.0	17.5	25.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.5*
.66	.78	1.44	.98	1.69	1.22	2.51	1.01	1.01	.78	.76	.69	.99	1.25	.92	1.34	*estimates*		Relative P/E Ratio	*1.10*
7.8%	6.4%	6.2%	5.4%	6.2%	6.6%	4.6%	5.9%	5.9%	5.7%	5.9%	4.9%	4.7%	5.0%	4.6%	4.7%			Avg Ann'l Div'd Yield	*3.9%*
						127.7	195.8	189.7	208.8	241.9	335.8	321.0	302.8	318.1	326.5	*465*	*515*	Revenues ($mill) A	*800*
						4.2	10.6	9.8	14.2	15.4	16.2	12.5	9.7	13.3	9.2	*12.7*	*13.8*	Net Profit ($mill)	*20.0*
						34.8%	37.1%	37.4%	36.5%	37.1%	35.0%	34.9%	34.2%	36.2%	37.9%	*37.5%*	*37.5%*	Income Tax Rate	*38.0%*
						3.3%	5.4%	5.2%	6.8%	6.4%	4.8%	3.9%	3.2%	4.2%	2.8%	*2.7%*	*2.7%*	Net Profit Margin	*2.5%*
						46.8%	50.6%	48.4%	50.9%	51.2%	50.7%	59.1%	55.9%	52.1%	59.4%	*56.0%*	*55.0%*	Long-Term Debt Ratio	*52.0%*
						50.0%	46.5%	48.7%	46.6%	48.8%	49.3%	40.9%	44.1%	47.9%	40.6%	*44.0%*	*45.0%*	Common Equity Ratio	*48.0%*
						217.8	239.4	228.5	245.6	244.2	246.6	279.1	255.5	247.4	292.5	*305*	*340*	Total Capital ($mill)	*470*
						255.7	265.2	276.6	282.3	284.8	294.2	299.6	312.3	334.6	342.5	*350*	*360*	Net Plant ($mill)	*465*
						3.4%	6.2%	6.1%	7.5%	8.1%	8.5%	6.4%	6.0%	7.7%	5.0%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
						3.6%	9.0%	8.3%	11.7%	12.9%	13.3%	10.9%	8.6%	11.2%	7.8%	*9.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
						3.5%	9.1%	8.3%	12.0%	12.9%	13.3%	10.9%	8.6%	11.2%	7.8%	*9.5%*	*9.0%*	Return on Com Equity	*9.0%*
						NMF	.7%	NMF	2.7%	4.0%	4.6%	1.7%	NMF	2.1%	NMF	*1.0%*	*2.0%*	Retained to Com Eq	*3.5%*
						NMF	93%	108%	78%	69%	65%	85%	110%	81%	118%	*87%*	*80%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 6/30/06

Total Debt $173.3 mill. Due in 5 Yrs $20.5 mill.
LT Debt $165.3 mill. LT Interest $10.0 mill.
(LT interest earned: 2.3x; total interest coverage: 2.3x)

Pension Assets-9/05 $58.5 mill. Oblig. $71.7 mill.

Pfd Stock None

Common Stock 11,505,996 shs as of 7/31/06

MARKET CAP: $300 million (Small Cap)

CURRENT POSITION A ($MILL.)	2004	2005	6/30/06
Cash Assets	.5	1.1	22.4
Other	65.9	141.0	57.9
Current Assets	66.4	142.1	80.3
Accts Payable	12.9	17.8	15.2
Debt Due	47.5	12.5	8.0
Other	38.6	111.9	43.8
Current Liab.	99.0	142.2	67.0
Fix. Chg. Cov.	269%	225%	235%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	3.0%	7.5%	*15.0%*
"Cash Flow"	2.0%	.5%	*9.0%*
Earnings	1.5%	-3.5%	*9.0%*
Dividends	--	--	*.5%*
Book Value	.5%	--	*10.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	100.5	109.3	53.8	39.2	302.8
2004	104.9	119.4	52.1	41.7	318.1
2005	104.6	117.7	56.3	47.9	326.5
2006	158.6	162.8	76.4	*67.2*	*465*
2007	*161*	*166*	*100*	*88.0*	*515*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.60	.67	d.18	d.22	.87
2004	.72	.79	d.05	d.26	1.19
2005	.59	.65	d.10	d.32	.82
2006	.70	.78	d.09	*d.29*	*1.10*
2007	*.73*	*.75*	*d.08*	*d.20*	*1.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.24	.24	.24	.24	.96
2003	.24	.24	.24	.24	.96
2004	.24	.24	.24	.24	.96
2005	.24	.24	.24	.24	.96
2006	.24	.24	.24		

BUSINESS: Cascade Natural Gas Corporation distributes natural gas to roughly 237,000 customers in Washington and Oregon. In 2005, total throughput was 108.2 billion cu. ft. Core customers: residential, commercial, firm industrial, interruptible (71% of oper. margin, 24% of gas deliveries); non-core: industrial, transportation service (29%, 76%). Serves pulp & paper, plywood, chem. fertilizers, oil refining, and food process. inds. Main connecting pipeline: Northwest Pipeline Corp. '05 deprec. rate: 2.9%. Est'd plant age: 12 yrs. Has around 375 employees. Officers and directors own 1.8% of com. (12/05 proxy). President and Chief Executive Officer: David W. Stevens. Inc.: WA. Address: 222 Fairview Ave. North, Seattle, WA 98109. Tel.: 206-624-3900. Internet: www.cngc.com.

Cascade Natural Gas Corporation has agreed to be acquired by MDU Resources Group, a diversified energy firm with 2005 revenues of approximately $3.5 billion. Under the terms of the $475 million transaction, which represented a 23% premium over the company's stock price before the announcement, Cascade stockholders would receive $26.50 in cash for each CGC share. Pending Cascade shareholder approval and other conditions, the deal is slated for completion by mid-2007. Note that our presentation for the company will be on a stand-alone basis until that time.

The utility ought to fit nicely with MDU's two regulated units, Montana-Dakota Utilities and Great Plains Natural Gas, which serve roughly 250,000 customers in five upper Midwest states, combined. Moreover, it appears that MDU has the resources to enable Cascade to reach even greater heights. We estimate that the purchase would be neutral to MDU's earnings in 2007 and 2008, due to integration costs. But accretion to the bottom line looks plausible in 2009 and thereafter, based partly on our assumption that cost savings come to the fore.

Meanwhile, the company's share earnings have bounced back considerably in fiscal 2006 (ends September 30th). The residential and commercial segment is enjoying an expanded customer base, as well as increased consumption (reflecting colder weather). What's more, management continues to succeed at keeping expenses under control. As such, it now appears that share net will jump about 34%, to $1.10, in fiscal 2006. Further expansion in operating margins ought to enable the bottom line to advance around 9%, to $1.20 a share, next year. (Cascade is awaiting the outcome of a rate-hike request, intended to generate additional annual revenues of $11.7 million, from the Washington Utilities and Transportation Commission.)

The Timeliness rank is suspended, since developments related to the pending merger, rather than earnings, are driving the shares' performance. The price tag seems reasonable, but the deal would have been sweeter if it had contained an option to convert CGC shares into MDU stock.

Frederick L. Harris, III September 15, 2006

(A) Cal. yr. thru. 12/95. Changed to 9/30 fiscal yr. in '96. (B) Primary egs. thru. '97, then diluted. Excl. nonrec. gains (losses): '91, 19¢; '93, 3¢; '96, (11¢); '98, (2¢); '99, (1¢); '01, 9¢; '02, (18¢); '03, (5¢); Q3 '06, 4¢. '04 egs don't add to total due to rounding. Next egs. rpt. due late Oct. (C) Dividends historically paid in the middle of Feb., May, Aug., Nov. ■Div'd reinvest. plan avail. (D) Incl. deferred charges. In '05: $68.0 mill., $5.96/sh. (E) In mill., adj. for stk. split.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	70

DELTA NAT. GAS NDQ-DGAS

RECENT PRICE 25.26 | TRAILING P/E RATIO 16.1 | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.8% | VALUE LINE

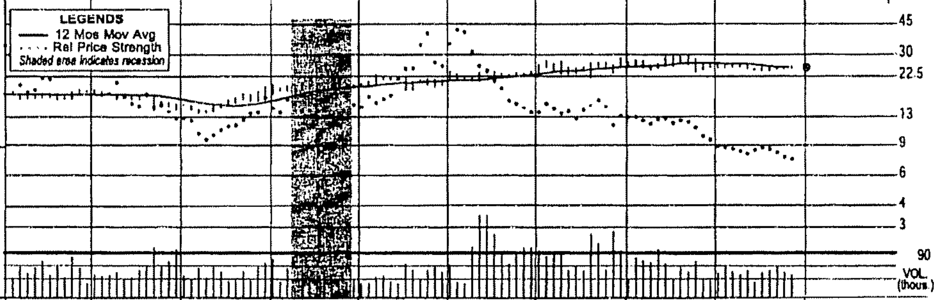
	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	19.25	19.00	19.62	20.99	23.08	24.10	28.75	30.00	26.82	High
Low	16.44	14.13	13.63	17.69	18.50	21.00	22.02	23.60	24.11	Low

RANKS

PERFORMANCE 3 Average
Technical 2 Above Average
SAFETY 2 Above Average
BETA .55 (1.00 = Market)

LEGENDS
— 12 Mos Mov Avg
···· Rel Price Strength
Shaded area indicates recession

Financial Strength B+
Price Stability 95
Price Growth Persistence 50
Earnings Predictability 65



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	18.64	16.02	18.68	28.36	22.11	21.59	24.74	26.06	36.01	
"CASH FLOW" PER SH	2.61	2.52	3.27	3.08	3.16	2.65	2.65	2.86	2.94	
EARNINGS PER SH	1.04	.90	1.42	1.47	1.45	1.49	1.20	1.55	1.55	*1.50 A,B/1.50 C*
DIV'DS DECL'D PER SH	1.14	1.14	1.14	1.14	1.16	1.18	1.18	1.18	1.20	
CAP'L SPENDING PER SH	4.71	3.31	3.58	2.83	3.72	2.90	2.80	1.65	2.39	
BOOK VALUE PER SH	12.55	12.39	12.73	13.12	13.51	14.49	15.26	15.73	16.16	
COMMON SHS OUTST'G (MILL)	2.38	2.41	2.46	2.50	2.53	3.17	3.20	3.23	3.26	
AVG ANN'L P/E RATIO	16.9	19.5	10.9	12.3	14.1	14.5	20.1	16.8	16.9	*16.8/16.8*
RELATIVE P/E RATIO	.88	1.11	.71	.63	.77	.83	1.06	.89	.91	
AVG ANN'L DIV'D YIELD	6.5%	6.5%	7.3%	6.3%	5.7%	5.5%	4.9%	4.5%	4.6%	
SALES ($MILL)	44.3	38.7	45.9	70.8	55.9	68.4	79.2	84.2	117.3	***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.***
OPERATING MARGIN	29.6%	34.0%	34.9%	23.2%	29.3%	24.7%	21.2%	21.9%	16.2%	
DEPRECIATION ($MILL)	3.8	3.9	4.6	4.0	4.4	4.5	4.7	4.3	4.6	
NET PROFIT ($MILL)	2.5	2.2	3.5	3.6	3.6	3.9	3.8	5.0	5.0	
INCOME TAX RATE	36.4%	36.6%	37.4%	38.0%	38.2%	38.0%	38.1%	38.3%	36.6%	
NET PROFIT MARGIN	5.5%	5.6%	7.5%	5.1%	6.5%	5.8%	4.8%	5.9%	4.3%	
WORKING CAP'L ($MILL)	d5.2	d9.3	d12.3	d12.8	d15.3	d.2	d.7	.9	4.6	
LONG-TERM DEBT ($MILL)	52.6	51.7	50.7	49.3	48.6	53.4	53.0	52.7	58.8	
SHR. EQUITY ($MILL)	29.8	29.9	31.3	32.8	34.2	45.9	48.8	50.8	52.6	
RETURN ON TOTAL CAP'L	5.0%	5.0%	6.6%	6.7%	6.6%	5.9%	5.6%	6.7%	6.7%	
RETURN ON SHR. EQUITY	8.2%	7.2%	11.1%	11.1%	10.6%	8.6%	7.9%	9.8%	9.5%	
RETAINED TO COM EQ	NMF	NMF	2.2%	2.5%	2.1%	1.6%	.2%	2.4%	2.1%	
ALL DIV'DS TO NET PROF	110%	NMF	80%	78%	80%	81%	98%	76%	77%	

A No. of analysts changing earn. est. in last 2 days: 0 up, 0 down, consensus 5-year earnings growth 2.0% per year. B Based upon 2 analysts' estimates. C Based upon one analyst's estimate.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	6.5%	38.0%
"Cash Flow"	-1.0%	2.5%
Earnings	2.5%	--
Dividends	1.0%	1.5%
Book Value	4.5%	2.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
06/30/04	10.1	16.8	35.7	16.6	79.2
06/30/05	9.8	25.8	33.4	15.2	84.2
06/30/06	14.2	42.1	46.5	14.5	117.3
06/30/07	13.1				

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
06/30/03	d.36	.27	1.66	d.08	1.49
06/30/04	d.28	.13	1.19	.16	1.20
06/30/05	d.35	.87	1.16	d.13	1.55
06/30/06	d.18	.89	1.03	d.19	1.55
06/30/07	d.16	*.70*	*1.12*	*d.17*	

Calendar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.295	.295	.295	.295	1.18
2004	.295	.295	.295	.295	1.18
2005	.295	.295	.30	.30	1.19
2006	.30	.30	.305	.305	1.21

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	7	5	8
to Sell	3	3	3
Hld's(000)	283	284	324

ASSETS ($mill.)	2005	2006	9/30/06
Cash Assets	.1	.2	.2
Receivables	6.6	7.9	7.3
Inventory (Avg cost)	10.2	11.8	17.8
Other	3.6	3.6	3.7
Current Assets	20.5	23.5	29.0
Property, Plant & Equip, at cost	174.7	182.2	--
Accum Depreciation	58.2	61.8	--
Net Property	116.5	120.4	120.8
Other	7.8	11.7	11.5
Total Assets	144.8	155.6	161.3
LIABILITIES ($mill.)			
Accts Payable	7.4	6.4	6.0
Debt Due	7.6	8.3	15.8
Other	4.6	4.2	4.2
Current Liab	19.6	18.9	26.0

LONG-TERM DEBT AND EQUITY as of 9/30/06

Total Debt $74.6 mill. **Due in 5 Yrs.** NA
LT Debt $58.8 mill.
Including Cap. Leases NA
(53% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '06 vs. None in '05

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 3,261,034 shares
(47% of Cap'l)

INDUSTRY: Natural Gas (Div.)

BUSINESS: Delta Natural Gas Company, Inc. sells natural gas to retail customers on its distribution system in central and southeastern Kentucky. As of March 31, the company sold natural gas to approximately 39,000 retail customers on its distribution system. It also transports natural gas to its industrial customers, who purchase their gas in the open market. In addition, Delta Natural transports natural gas on behalf of local producers and customers not on its distribution system. Delta Natural Gas serves residential, commercial, and industrial customers in the areas of Nicholasville, Corbin, and Berea, Kentucky. As of the above date, the company served approximately 8,000 customers in Nicholasville, approximately 6,000 in Corbin, and approximately 4,000 in Berea. Has 156 employees. Chairman: Harrison D. Peet. Inc.: KY. Address: 3617 Lexington Road, Winchester, KY 40391. Tel.: (859) 744-6171. Internet: http://www.deltagas.com.

L.Y.

December 15, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 11/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
2.01%	5.46%	4.11%	24.75%	60.02%

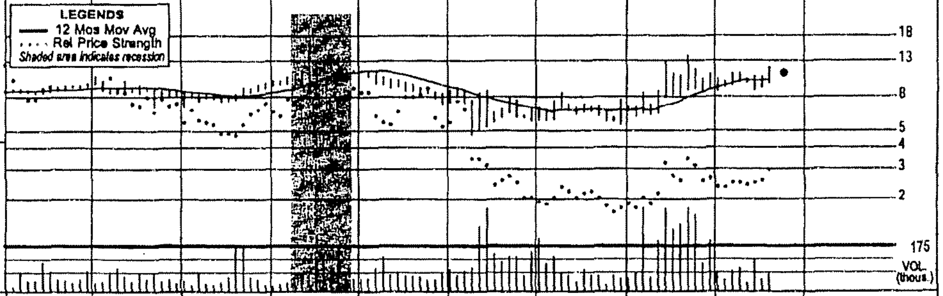
ENERGY WEST INC. NDQ-EWST

RECENT PRICE 11.00 | TRAILING P/E RATIO 17.5 | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.6% | VALUE LINE

RANKS											
	9.75 / 8.38	10.63 / 7.00	9.75 / 7.00	16.50 / 9.05	11.50 / 7.25	9.00 / 4.74	8.50 / 5.41	13.89 / 6.05	11.94 / 8.57		High / Low

PERFORMANCE 3 Average
Technical 2 Above Average
SAFETY 4 Below Average
BETA .35 (1.00 = Market)

Financial Strength C++
Price Stability 30
Price Growth Persistence 30
Earnings Predictability 15



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	17.92	21.97	29.17	47.72	38.72	30.50	28.21	26.34	--	
"CASH FLOW" PER SH	1.35	1.35	1.28	2.05	1.45	.97	.68	1.27	--	
EARNINGS PER SH	.64	.66	.53	1.10	.55	d.03	d.21	.53	NA	NA/NA
DIV'DS DECL'D PER SH	.45	.45	.49	.51	.53	.41	--	--	--	
CAP'L SPENDING PER SH	1.25	1.53	1.92	1.30	2.50	1.59	.89	.96	--	
BOOK VALUE PER SH	5.33	5.56	5.64	6.21	6.32	5.89	5.16	5.90	--	
COMMON SHS OUTST'G (MILL)	2.40	2.43	2.48	2.51	2.57	2.60	2.60	2.91	--	
AVG ANN'L P/E RATIO	13.7	13.9	15.9	8.5	20.2	--	--	13.0	NA	NA/NA
RELATIVE P/E RATIO	.71	.79	1.03	.44	1.10	--	--	.69	--	
AVG ANN'L DIV'D YIELD	5.1%	4.9%	5.8%	5.4%	4.7%	5.0%	--	--	--	
SALES ($MILL)	43.1	53.5	72.2	119.9	99.6	79.1	73.3	76.7	--	*Bold figures*
OPERATING MARGIN	14.2%	10.6%	7.8%	7.6%	6.6%	5.9%	6.5%	10.9%	--	*are consensus*
DEPRECIATION ($MILL)	1.7	1.7	1.9	2.4	2.3	2.6	2.3	2.3	--	*earnings*
NET PROFIT ($MILL)	1.5	1.6	1.3	2.8	1.4	d.1	d.6	1.4	--	*estimates*
INCOME TAX RATE	34.2%	38.1%	36.6%	36.3%	38.4%	--	--	35.3%	--	*and, using the*
NET PROFIT MARGIN	3.5%	3.0%	1.8%	2.3%	1.4%	NMF	NMF	1.8%	--	*recent prices,*
WORKING CAP'L ($MILL)	5.6	4.2	1.5	2.2	d.8	d3.4	.0	3.9	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	17.3	16.8	16.4	15.9	15.4	14.8	21.7	18.7	--	
SHR. EQUITY ($MILL)	12.8	13.5	14.0	15.6	16.3	15.3	13.4	17.2	--	
RETURN ON TOTAL CAP'L	7.1%	7.3%	6.3%	10.7%	6.3%	1.6%	1.2%	7.0%	--	
RETURN ON SHR. EQUITY	11.9%	11.8%	9.3%	17.7%	8.6%	NMF	NMF	8.0%	--	
RETAINED TO COM EQ	5.1%	4.3%	2.0%	10.9%	.2%	NMF	NMF	8.0%	--	
ALL DIV'DS TO NET PROF	57%	64%	78%	30%	97%	NMF	--	--	--	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	4.5%	-6.5%
"Cash Flow"	-6.0%	85.5%
Earnings	--	--
Dividends	--	--
Book Value	0.5%	14.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
06/30/04	12.5	22.6	24.5	13.7	73.3
06/30/05	11.9	22.9	27.8	14.1	76.7
06/30/06	10.3	28.9	32.2		
06/30/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
06/30/03	d.40	.05	.69	d.37	d.03
06/30/04	d.19	.08	.23	d.33	d.21
06/30/05	d.43	.22	.84	d.10	.53
06/30/06	d.21	.38	.56		
06/30/07					

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.405	--	--	--	.41
2004	--	--	--	--	--
2005	--	--	--	.04	.04
2006	.05	.08	.10		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	6	4	3
to Sell	--	2	--
Hld's(000)	110	80	94

ASSETS ($mill.)	2004	2005	3/31/06
Cash Assets	1.3	.1	.5
Receivables	7.6	8.7	14.1
Inventory (Avg cost)	5.5	4.2	3.6
Other	2.4	2.4	.6
Current Assets	16.7	15.4	18.8
Property, Plant & Equip, at cost	69.0	71.6	--
Accum Depreciation	30.4	32.7	--
Net Property	38.6	38.9	39.0
Other	6.1	5.1	4.5
Total Assets	61.4	59.4	62.3
LIABILITIES ($mill.)			
Accts Payable	3.6	2.7	5.8
Debt Due	7.7	4.9	2.5
Other	5.4	3.9	4.6
Current Liab	16.7	11.5	12.9

LONG-TERM DEBT AND EQUITY as of 3/31/06

Total Debt $20.8 mill. **Due in 5 Yrs.** NA
LT Debt $18.3 mill.
Including Cap. Leases NA
(49% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability $ 3 mill. in '05 vs. $.3 mill. in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 2,931,158 shares
(51% of Cap'l)

INDUSTRY: Natural Gas (Distrib.)

BUSINESS: Energy West, Inc. distributes natural gas to its customers in the Great Falls, Montana and Cody, Wyoming areas. Its regulated utility operations include the distribution of natural gas through an underground system in West Yellowstone, Montana, which is supplied by liquefied natural gas. The company conducts certain nonregulated, nonutility operations through its three wholly owned subsidiaries, Energy West Propane, Inc.; Energy West Resources, Inc.; and Energy West Development, Inc. Energy West Propane is engaged in the distribution of bulk propane in Wyoming, South Dakota, Nebraska, Colorado, Arizona, and Montana. Energy West Resources is involved in gas storage, a small amount of oil and gas development, and the marketing and transportation of gas in Montana. Energy West Development owns two real estate properties in Great Falls, Montana. Has 111 employees. Chairman: G. Montgomery Mitchell. Inc.: MT. Address: 1 First Avenue South, Great Falls, MT 59401. Tel.: (406) 791-7500. Internet: http://www.energywest.com.

A.O.

September 15, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 8/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
20.13%	26.02%	25.74%	79.62%	6.51%

ENERGYSOUTH INC. NDQ–ENSI

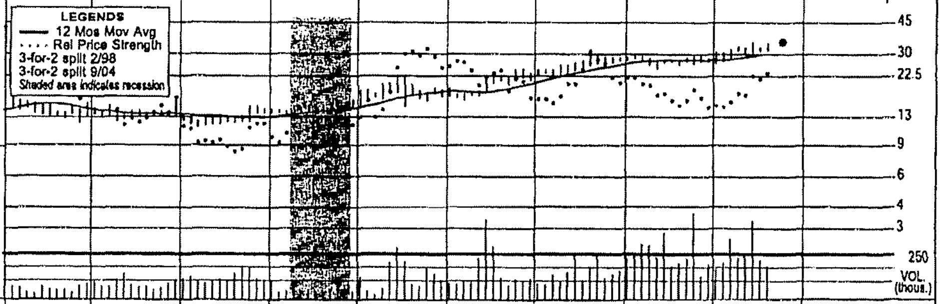
RECENT PRICE **35.15** | TRAILING P/E RATIO **20.0** | RELATIVE P/E RATIO **1.05** | DIV'D YLD **2.6%** | VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	18.33	16.67	15.33	16.57	22.63	24.76	29.67	29.91	35.20	High
Low	12.00	12.17	11.33	13.57	14.70	16.39	22.08	24.65	26.40	Low

RANKS

PERFORMANCE	3	Average
Technical	3	Average
SAFETY	2	Above Average
BETA .60		(1.00 = Market)

Financial Strength	B++
Price Stability	95
Price Growth Persistence	85
Earnings Predictability	90



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	10.13	9.27	10.06	14.55	11.41	12.94	14.82	15.78	–	
"CASH FLOW" PER SH	2.06	2.10	2.15	2.06	2.49	2.65	2.89	3.08	–	
EARNINGS PER SH	1.14	1.17	1.19	1.01	1.35	1.45	1.60	1.74	***1.78*** [A,B]	***1.88*** [C]***/NA***
DIV'DS DECL'D PER SH	.56	.61	.66	.68	.71	.74	.78	.83	–	
CAP'L SPENDING PER SH	1.05	1.37	1.57	5.88	3.38	2.04	1.10	2.08	–	
BOOK VALUE PER SH	8.20	8.74	9.30	9.47	10.21	10.99	11.99	12.98	–	
COMMON SHS OUTST'G (MILL)	7.31	7.34	7.37	7.41	7.57	7.70	7.83	7.90	–	
AVG ANN'L P/E RATIO	13.6	11.8	10.7	14.1	12.9	13.1	15.3	16.0	***19.7***	***18.7/NA***
RELATIVE P/E RATIO	.71	.67	.70	.72	.70	.75	.81	.85	–	
AVG ANN'L DIV'D YIELD	3.6%	4.4%	5.2%	4.8%	4.1%	3.9%	3.2%	3.0%	–	
SALES ($MILL)	74.0	68.1	74.1	107.8	86.4	99.6	116.0	124.6	–	*Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.*
OPERATING MARGIN	41.0%	45.8%	43.1%	32.6%	47.0%	44.9%	40.6%	39.9%	–	
DEPRECIATION ($MILL)	6.6	6.8	7.1	7.7	8.6	9.3	10.1	10.5	–	
NET PROFIT ($MILL)	8.4	8.6	8.8	7.6	10.2	11.1	12.6	13.8	–	
INCOME TAX RATE	37.1%	36.7%	37.5%	37.8%	36.9%	37.6%	37.7%	39.4%	–	
NET PROFIT MARGIN	11.4%	12.7%	11.9%	7.0%	11.8%	11.2%	10.8%	11.1%	–	
WORKING CAP'L ($MILL)	1.8	3.1	1.6	1.8	3.2	1.8	7.4	5.2	–	
LONG-TERM DEBT ($MILL)	59.0	58.0	55.2	90.6	98.6	92.6	84.7	77.8	–	
SHR. EQUITY ($MILL)	59.9	64.2	68.5	70.1	77.3	84.7	93.9	102.5	–	
RETURN ON TOTAL CAP'L	9.4%	9.2%	9.1%	7.3%	8.7%	9.0%	9.3%	9.7%	–	
RETURN ON SHR. EQUITY	14.1%	13.5%	12.8%	10.8%	13.2%	13.2%	13.4%	13.5%	–	
RETAINED TO COM EQ	7.9%	7.2%	6.4%	3.6%	6.4%	6.5%	6.9%	7.3%	–	
ALL DIV'DS TO NET PROF	44%	47%	50%	66%	52%	51%	48%	46%	–	

[A] No. of analysts changing earn. est. in last 2 days: 0 up, 0 down, consensus 5-year earnings growth 5.0% per year. [B] Based upon one analyst's estimate. [C] Based upon one analyst's estimate.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	8.0%	6.5%
"Cash Flow"	6.5%	6.5%
Earnings	6.5%	8.5%
Dividends	5.0%	6.5%
Book Value	6.5%	8.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
09/30/04	32.7	42.9	21.0	19.4	116.0
09/30/05	36.3	44.1	22.4	21.8	124.6
09/30/06	44.8	46.1	23.1		
09/30/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
09/30/03	.44	.73	.13	.15	1.45
09/30/04	52	81	17	.10	1.60
09/30/05	55	85	18	16	1.74
09/30/06	.56	.84	20	*.19*	
09/30/07	*.58*	*.92*			

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.18	.18	.19	.19	.74
2004	.19	.19	.20	.20	.78
2005	.20	.20	.215	.215	.83
2006	.215	.215	.23		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	19	17	19
to Sell	14	22	23
Hld's(000)	2430	2304	2313

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	9.5	9.7	1.2
Receivables	8.9	10.4	9.6
Inventory (Avg cost)	5.8	7.0	6.4
Other	7.0	7.4	10.7
Current Assets	31.2	34.5	27.9
Property, Plant & Equip, at cost	275.0	289.9	--
Accum Depreciation	70.4	78.0	--
Net Property	204.6	211.9	222.6
Other	6.7	6.1	5.8
Total Assets	242.5	252.6	256.3
LIABILITIES ($mill.)			
Accts Payable	5.3	8.2	7.5
Debt Due	6.2	5.2	5.0
Other	12.3	17.9	15.1
Current Liab	23.8	29.3	27.6

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $77.8 mill. **Due in 5 Yrs.** NA
LT Debt $72.9 mill.
Including Cap. Leases NA
(40% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability $.8 mill. in '05 vs. $.5 mill. in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 7,936,000 shares
(60% of Cap'l)

INDUSTRY: Natural Gas (Distrib.)

BUSINESS: EnergySouth, Inc., through its subsidiaries, operates in three segments: natural gas distribution, natural gas storage, and other energy-related services. Through Mobile Gas, it is engaged in the purchase, distribution, sale, and transportation of natural gas to over 97,000 residential, commercial, and industrial customers in southwest Alabama, including the city of Mobile and adjacent areas. Through EnergySouth Services, Inc., the company provides contract and consulting work for utilities and industrial customers. Through MGS Marketing Services, Inc., it assists existing and potential customers in the purchase of natural gas. The company also holds a general partnership interest of 87.5% in Bay Gas Storage Company, Ltd., which owns an underground gas storage cavern and related pipeline facilities. Has 261 employees. Chairman: John C. Hope III. Inc.: AL. Address: 2828 Dauphin Street, Mobile, AL 36606. Tel.: (251) 450-4774. Internet: http://www.energysouth.com.

A.O.

September 15, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 8/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
9.04%	17.23%	27.04%	72.00%	165.83%

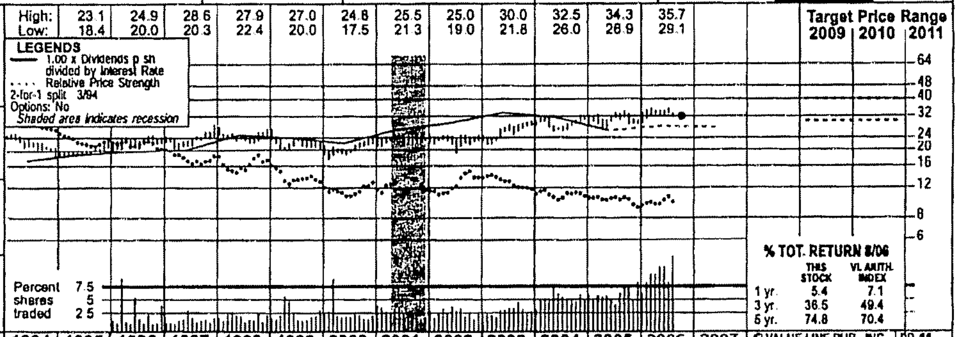
LACLEDE GROUP NYSE-LG

RECENT PRICE 32.13 | P/E RATIO 15.5 (Trailing: 14.8 Median: 15.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 4 Raised 9/8/06
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 9/15/06
BETA .85 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	23.1	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	35.7
Low:	18.4	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/94
Options: No
Shaded area indicates recession



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	30	(-5%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	1	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	50	67	60
to Sell	37	30	47
Hld's(000)	8521	9470	10115

% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.4	7.1
3 yr.	36.5	49.4
5 yr.	74.8	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
30.21	28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	*93.50*	*98.60*	Revenues per sh	*116.65*
2.13	2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	*3.70*	*3.85*	"Cash Flow" per sh	*4.70*
1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	*2.15*	*2.15*	Earnings per sh A B	*2.50*
1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	*1.40*	*1.43*	Div'ds Decl'd per sh C■	*1.50*
1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	*3.15*	*3.40*	Cap'l Spending per sh	*4.40*
11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	*19.70*	*20.65*	Book Value per sh D	*26.00*
15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	*21.50*	*21.50*	Common Shs Outst'g E	*24.00*
14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	*Value Line*		Relative P/E Ratio	*.95*
7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
	544.8	602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	*2010*	*2120*	Revenues ($mill) A	*2800*
	32.8	32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	*46.0*	*46.0*	Net Profit ($mill)	*60.0*
	35.9%	38.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	*34.0%*	*34.0%*	Income Tax Rate	*35.0%*
	6.0%	5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	*2.3%*	*2.2%*	Net Profit Margin	*2.1%*
	42.5%	38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	*49.0%*	*49.0%*	Long-Term Debt Ratio	*48.0%*
	57.1%	61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	*51.0%*	*51.0%*	Common Equity Ratio	*52.0%*
	422.2	406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	*830*	*870*	Total Capital ($mill)	*1200*
	452.2	467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	679.5	*775*	*815*	Net Plant ($mill)	*1050*
	9.4%	9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.7%	*7.0%*	*7.0%*	Return on Total Cap'l	*6.5%*
	13.5%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	*11.0%*	*10.5%*	Return on Shr. Equity	*9.5%*
	13.6%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	*11.0%*	*10.5%*	Return on Com Equity	*9.5%*
	4.5%	3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	*4.0%*	*3.5%*	Retained to Com Eq	*4.0%*
	67%	70%	83%	89%	98%	83%	113%	74%	73%	72%	*65%*	*67%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $518.8 mill. Due in 5 Yrs $175.0 mill.
LT Debt $395.4 mill. LT Interest $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $1.7 mill.
Pension Assets-9/05 $272.8 mill. Oblig. $327.2 mill.
Pfd Stock $.8 mill. Pfd Div'd $.05 mill.
Common Stock 21,357,009 shs.
as of 7/28/06

MARKET CAP: $675 million (Small Cap)

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	13.9	6.0	31.9
Other	323.7	418.1	319.1
Current Assets	337.6	424.1	351.0
Accts Payable	68.4	138.4	118.2
Debt Due	96.5	110.7	123.4
Other	97.7	116.5	181.1
Current Liab.	262.6	365.6	304.5
Fix. Chg. Cov.	279%	293%	290%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	17.0%	*10.5%*
"Cash Flow"	1.0%	1.5%	*8.0%*
Earnings	2.5%	4.5%	*5.0%*
Dividends	1.0%	.5%	*2.0%*
Book Value	3.0%	2.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	280.1	422.2	186.6	161.4	1050.3
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.5	*281.5*	*2010*
2007	*635*	*655*	*440*	*390*	*2120*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.80	1.14	.11	d.21	1.82
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	*d.26*	*2.15*
2007	*1.15*	*1.05*	*.25*	*d.30*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.335	.335	.335	.335	1.34
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 8 other counties. Has more than 630,000 customers. Purchased SM&P for $43 million (1/02). Therms sold and transported in fiscal 2005: 1.12 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 23%; transportation, 2%; other, 15%. Has around 3,815 employees. Officers and directors own approximately 6.0% of common shares (1/06 Proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.lacledegas.com.

Laclede Group is on track to register healthy results in fiscal 2006 (ends September 30th). Laclede Energy Resources, the non-utility gas marketing segment, is still benefiting from supply/demand imbalances resulting from last year's Gulf Coast hurricanes, plus a surge in volumes (reflecting higher interstate pipeline wholesale transactions). Furthermore, SM&P Utility Resources, the unregulated unit specializing in locating and marking services for underground facilities, is being aided by new business signups in existing markets. And we note that this subsidiary recently bought Reliant Services, which provides similar services. Given that both businesses have customers in the same geographic areas, synergies ought to generate decent cost savings going forward.

But the core natural gas unit has underperformed of late. This can be attributed partly to higher operation and maintenance expenses, as well as an increased provision for uncollectible accounts. A decline in volumes within the service territory has further eroded earnings. On the bright side, there have been benefits from a general rate hike effective since last October, and income from entities located outside the system has been rising.

On a consolidated basis, share net ought to grow about 13%, to $2.15, in fiscal 2006. Laclede's bottom line may flatten out next year because of the difficult comparison.

We believe that unexciting results are in store for the company over the 2009-2011 timeframe. The market in which the natural gas division operates has sluggish customer growth because it is in a mature stage. Moreover, it appears that major acquisitions are not likely to take place anytime soon. Consequently, annual share-net gains may only be in the mid-single-digit range, with some volatility, over the 3- to 5-year horizon.

The stock's good yield aside, total-return potential is not appealing. That is because these shares are already trading within our 2009-2011 Target Price Range, and we are assuming that future dividend increases will be moderate. Also, the Timeliness rank is 4 (Below Average).

Frederick L. Harris, III September 15, 2006

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: Q2 '06, 7¢. Next earnings report due late Oct.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '05: $203.8 mill., $9.63/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

NEW JERSEY RES. NYSE-NJR

RECENT PRICE **49.55** | P/E RATIO **20.6** (Trailing: 16.2 Median: 15.0) | RELATIVE P/E RATIO **1.21** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS **4** Raised 2/17/06
SAFETY **1** Raised 9/15/06
TECHNICAL **2** Raised 8/25/06
BETA .60 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	50	(Nil)	3%

Insider Decisions

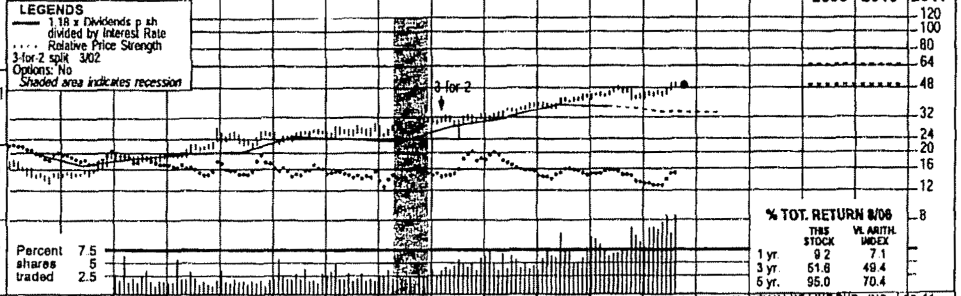
	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	4	0	0	5	0	0	2	0
to Sell	1	4	0	0	4	0	0	2	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	64	71	73
to Sell	60	52	60
Hld's(000)	13455	14778	16255

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	20.3	19.9	28.0	26.8	27.4	29.8	32.5	33.6	39.5	44.6	49.3	51.4	
Low:	14.3	17.8	18.8	21.0	22.4	24.1	24.8	24.3	30.0	36.5	40.7	41.5	

LEGENDS
—— 1.18 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
Options: No
Shaded area indicates recession



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.2	7.1
3 yr.	51.6	49.4
5 yr.	95.0	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
16.01	15.89	16.88	18.02	19.22	17.03	20.22	25.97	26.59	33.98	44.13	76.82	66.17	93.43	91.33	114.29	*117.45*	*120.60*	Revenues per sh A	*129.80*
1.54	1.58	1.95	2.14	2.31	2.13	2.22	2.45	2.60	2.79	2.99	3.18	3.21	3.58	3.75	3.92	*4.00*	*4.20*	"Cash Flow" per sh	*4.70*
.65	.55	1.09	1.15	1.28	1.29	1.37	1.48	1.55	1.66	1.79	1.95	2.09	2.38	2.55	2.65	*2.80*	*2.90*	Earnings per sh B	*3.30*
.96	1.00	1.01	1.01	1.01	1.01	1.03	1.07	1.09	1.12	1.15	1.17	1.20	1.24	1.30	1.36	*1.45*	*1.50*	Div'ds Decl'd per sh C■	*1.70*
4.37	2.91	1.99	2.31	2.10	1.77	1.78	1.72	1.60	1.81	1.85	1.66	1.53	1.71	2.17	1.92	*1.80*	*1.95*	Cap'l Spending per sh	*2.10*
8.85	8.57	9.44	9.81	9.64	9.70	10.10	10.38	10.88	11.35	12.43	13.20	13.06	15.38	16.87	15.90	*17.45*	*18.80*	Book Value per sh	*23.15*
20.28	20.95	24.43	25.23	25.95	26.69	27.13	26.82	26.72	26.61	26.39	26.66	27.67	27.23	27.74	27.55	*28.10*	*28.20*	Common Shs Outst'g D	*28.50*
24.0	22.3	12.4	15.1	13.0	11.7	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
1.78	1.42	.75	.89	.85	.78	.85	.78	.80	.87	.96	.73	.80	.80	.81	.90	*Value Line*		Relative P/E Ratio	*1.15*
6.2%	8.1%	7.5%	5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $490.8 mill. Due in 5 Yrs $250.0 mill.
LT Debt $333.8 mill. LT Interest $22.0 mill.
Incl. $6.9 mill. capitalized leases.
(LT interest earned: 5.5x; total interest coverage: 4.8x)
Pension Assets-9/05 $82.6 mill. Oblig. $99.9 mill.

Pfd Stock None

Common Stock 28,080,314 shs.
as of 8/8/06
MARKET CAP: $1.4 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
548.5	696.5	710.3	904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	*3300*	*3400*	Revenues ($mill) A	*3700*
38.7	41.5	43.3	44.9	47.9	52.3	56.8	65.4	71.6	74.4	*80.0*	*82.0*	Net Profit ($mill)	*95.0*
32.6%	33.3%	30.4%	36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
7.1%	6.0%	6.1%	5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	*2.4%*	*2.4%*	Net Profit Margin	*2.5%*
50.7%	49.3%	51.2%	48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	*42.0%*	*41.0%*	Long-Term Debt Ratio	*37.0%*
45.8%	47.1%	45.6%	51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	*58.0%*	*59.0%*	Common Equity Ratio	*63.0%*
598.2	590.6	638.2	590.4	620.1	706.2	732.4	676.8	783.8	755.3	*845*	*890*	Total Capital ($mill)	*1055*
655.2	659.4	680.0	705.4	730.6	743.9	756.4	852.6	880.4	905.1	*935*	*970*	Net Plant ($mill)	*1120*
8.1%	8.6%	8.1%	9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	*10.5%*	*10.5%*	Return on Total Cap'l	*10.5%*
13.1%	13.9%	13.9%	14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	*16.0%*	*15.5%*	Return on Shr. Equity	*14.5%*
13.5%	14.3%	14.4%	14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	*16.0%*	*15.5%*	Return on Com Equity	*14.5%*
3.4%	4.0%	4.4%	5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	*8.0%*	*7.5%*	Retained to Com Eq	*7.0%*
76%	73%	71%	67%	63%	59%	56%	51%	49%	50%	*52%*	*52%*	All Div'ds to Net Prof	*52%*

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	5.0	25.0	4.7
Other	681.0	927.8	808.7
Current Assets	686.0	952.8	813.4
Accts Payable	42.9	54.7	38.0
Debt Due	287.4	177.4	157.0
Other	357.4	744.2	510.4
Current Liab.	687.7	976.3	705.4
Fix. Chg. Cov.	826%	660%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	18.5%	23.5%	*4.5%*
"Cash Flow"	5.5%	6.0%	*4.0%*
Earnings	7.5%	8.5%	*4.5%*
Dividends	2.5%	3.0%	*4.5%*
Book Value	5.0%	7.0%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	668.9	1152.7	369.7	353.1	2544.4
2004	643.0	1037.7	438.5	414.4	2533.6
2005	854.0	1065.1	544.3	684.9	3148.3
2006	1164.6	1064.4	536.1	*534.9*	*3300*
2007	*1085*	*1150*	*610*	*555*	*3400*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.85	1.50	.16	d.13	2.38
2004	.87	1.82	.06	d.20	2.55
2005	.91	1.84	.07	d.17	2.65
2006	1.23	2.14	d.14	*d.43*	*2.80*
2007	*1.13*	*1.84*	*.10*	*d.17*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.30	.30	.30	.30	1.20
2003	.31	.31	.31	.31	1.24
2004	.325	.325	.325	.325	1.30
2005	.34	.34	.34	.34	1.36
2006	.36	.36	.36		

BUSINESS: New Jersey Resources Corp. is the holding company for New Jersey Natural Gas Co., a natural gas utility (about 463,000 customers at 9/30/05) in Monmouth, Ocean, and parts of other N.J. counties. Fiscal 2005 volume: 124.7 bill. cu ft. (50% firm, 8% interruptible industrial and electric utility, 42% off-system and capacity release). New Jersey Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy services to customers in 17 states. 2005 deprec. rate: 2.8%. Est'd plant age: 8 years. Has 551 utility employees, 16,300 stckhldrs. Off. & dir. own about 3% of common stock (12/05 Proxy). Chairman and CEO: Laurence M. Downes. Inc.: N.J. Address: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1000. Internet: www.njliving.com.

New Jersey Resources results over the first nine months of fiscal 2006 (year ends September 30th) have been solid. Earnings over this timeframe increased about 14.5%, to $3.23 a share, with most of the gains being driven by an improved performance at the company's energy services subsidiary. In fact, the segment posted an earnings advance of about 90% this year due to growth in its portfolio of storage and transportation contracts. Since the unit covers many markets in the eastern half of the United States and Canada, it is able to capture additional value when prices fluctuate between regions. All told, the business now represents over 20% of corporate earnings.

The third quarter was a weak one at the company's main subsidiary, New Jersey Natural Gas (NJNG). It posted earnings of $1.7 million, well below the $3.9 million in the year-earlier period. The decrease was primarily the result of conservation by customers. The utility currently has a weather normalization plan in place to protect against temperatures that are warmer than normal, though, it is unable to protect against lower usage. Therefore, in December, NJNG proposed a plan with the New Jersey Board of Public Utilities to implement a conservation usage adjustment (CUA) plan to replace the normalization policy, which would provide protection against both temperature and usage changes. Management remains optimistic that the program will be approved and be in place by next winter's heating season. However, should regulatory approval not be granted, the company is exploring alternatives that includes filing for a rate increase. Meanwhile, the utility added about 7,870 new customers through the third quarter, and will likely grow at a rate above the industry average for the next few years thanks to the strong demographics of the region NJNG serves. About a third of new customers are conversions from other fuel sources.

Though untimely, this stock offers decent total return potential. This is largely due to expanding profits from its nonutility operations. Other pluses include the likelihood of a more consistent earnings stream through the CUA proposal, and steady dividend increases.

Evan I. Blatter *September 15, 2006*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Next earnings report due late Oct.
(C) Dividends historically paid in early January, April, July, and October ■ Dividend reinvestment plan available.
(D) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	100

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 38.19 | P/E RATIO 16.7 (Trailing: 17.6 Median: 15.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Raised 8/25/06
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 9/15/06
BETA .75 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	40	(+5%)	5%

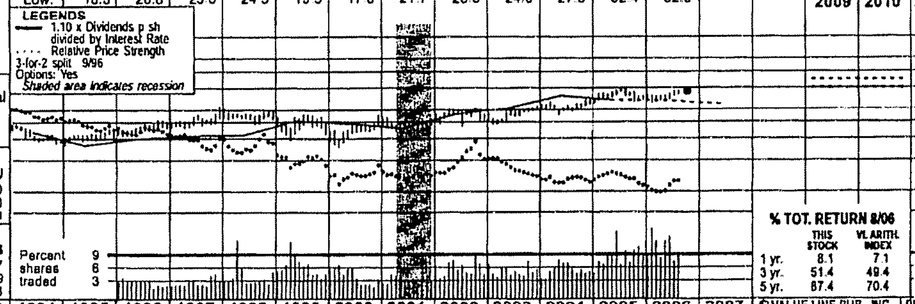
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	1	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	1	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	59	62	77
to Sell	54	59	59
Hld's(000)	12922	13095	14328

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	22.8	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	38.8
Low:	18.3	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.1	7.1
3 yr.	51.4	49.4
5 yr.	87.4	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
17.02	16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	**39.65**	**42.25**	Revenues per sh	**51.80**
3.22	2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	**4.60**	**4.75**	"Cash Flow" per sh	**5.10**
1.62	.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	**2.22**	**2.40**	Earnings per sh [A]	**2.85**
1.10	1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	**1.38**	**1.42**	Div'ds Decl'd per sh [B]■	**1.70**
3.85	3.58	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	**3.70**	**3.60**	Cap'l Spending per sh	**3.60**
12.61	12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	**22.10**	**22.95**	Book Value per sh	**25.55**
17.41	17.68	19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	**27.75**	**27.80**	Common Shs Outst'g [C]	**28.00**
10.2	28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	*Value Line*		Relative P/E Ratio	**.95**
6.7%	5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	*estimates*		Avg Ann'l Div'd Yield	**4.3%**
						380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	**1025**	**1050**	Revenues ($mill)	**1450**
						46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	**62.0**	**66.5**	Net Profit ($mill)	**80.0**
						38.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
						12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	**5.7%**	**5.7%**	Net Profit Margin	**5.5%**
						41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	**47.0%**	**47.0%**	Long-Term Debt Ratio	**47%**
						52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	**53.0%**	**53.0%**	Common Equity Ratio	**53%**
						657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	**1150**	**1200**	Total Capital ($mill)	**1350**
						745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	**1375**	**1400**	Net Plant ($mill)	**1500**
						8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
						12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	**10.0%**	**10.5%**	Return on Shr. Equity	**10.5%**
						12.7%	11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	**10.0%**	**10.5%**	Return on Com Equity	**10.5%**
						5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	**3.7%**	**3.7%**	Retained to Com Eq	**3.8%**
						63%	70%	118%	74%	70%	67%	79%	72%	69%	63%	**62%**	**59%**	All Div'ds to Net Prof	**60%**

CAPITAL STRUCTURE as of 6/30/06
Total Debt $577.3 mill. Due in 5 Yrs $204.2 mill.
LT Debt $492.0 mill. LT Interest $31.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/05 $218.6 mill.
Oblig. $267.9 mill.
Pfd Stock None

Common Stock 27,548,346 shs
as of 7/31/06
MARKET CAP $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	5.2	7.1	6.6
Other	231.9	316.6	191.5
Current Assets	237.1	323.7	198.1
Accts Payable	102.5	135.3	76.8
Debt Due	117.5	134.7	85.3
Other	47.3	56.6	53.0
Current Liab.	267.3	326.6	215.1
Fx. Chg. Cov.	316%	340%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	4.5%	8.0%	*11.0%*
"Cash Flow"	1.5%	2.5%	*4.5%*
Earnings	1.5%	5.0%	*7.0%*
Dividends	1.0%	1.0%	*4.0%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	*130*	*333.6*	*1025*
2007	*375*	*185*	*140*	*350*	*1050*

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	*d.30*	*.97*	*2.22*
2007	*1.55*	*.05*	*d.30*	*1.10*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345		

BUSINESS: Northwest Natural Gas Co. distributes natural gas at retail to 90 communities, 624,000 customers, in Oregon (90% of custs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system to bring gas to market. Owns local underground storage. Rev. breakdown: residential, 53%; commercial, 27%; industrial, gas transportation, and other, 20%. Employs 1,305. Barclays owns 6.2% of shares; insiders, 1% (4/06 proxy). CEO: Mark S. Dodson. Inc.: OR. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's second-quarter earnings turned out a bit better than expected, despite weather that was 16% warmer than average and 12% warmer than last year's. The company's share of commodity cost savings added about $0.03 a share in the June period, and profits from interstate gas storage contributed an additional $0.02. Operations and maintenance expenses were up 3% but would have risen 2% without increased bad debt costs, due to higher gas prices.

We anticipate roughly normal earnings growth over the balance of the year. Northwest Natural increased its customer count by 3.3% in the 12 months ended in June, and the new accounts should boost earnings through 2006 and 2007. While the national economy is definitely slowing, Portland seems to be doing better than the nation as a whole, with little decline in new home construction. (Northwest's share of new home heating fuel is over 90%.) But the company plans to lay off 50 to 100 employees in the second half of the year, and severance costs will probably add up to around $0.04 a share in the fourth quarter.

Earnings in 2007 will likely benefit from new efficiency and cost-cutting efforts. Northwest has begun to implement a companywide plan to reduce costs by consolidating some operations, standardizing functions, and outsourcing some operations, such as new construction. The plan will take a few years to implement completely and will probably result in a workforce reduction of 200 to 250 employees, some by normal attrition.

Northwest's earnings will probably grow faster than its industry's, thanks to above-average customer growth. The area to the southeast of Portland will soon be zoned for higher density, permitting profitable installation of gas mains and significant customer growth. And the company serves less than 60% of its market at present, allowing it to pick up new customers as old oil tanks need replacing.

These neutrally ranked shares have below-average total return potential at their recent quotation. Although we like Northwest's prospects, we think investors will have an opportunity to invest at a better price.

Sigourney B. Romaine September 15, 2006

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due early November.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock split.

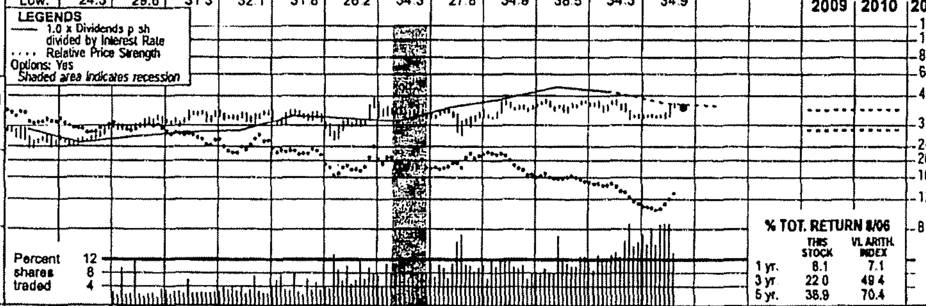
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	75

PEOPLES ENERGY NYSE-PGL

RECENT PRICE 41.41 | P/E RATIO 31.9 (Trailing: 23.9 Median: 14.0) | RELATIVE P/E RATIO 1.88 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS – Susp. 7/21/06
SAFETY 2 Lowered 3/17/06
TECHNICAL – Susp. 7/21/06
BETA .85 (1.00 = Market)

High:	32.0	37.4	39.9	40.1	40.3	46.9	44.6	40.4	45.3	46.0	45.5	43.9
Low:	24.3	29.6	31.3	32.1	31.8	26.2	34.3	27.8	34.9	38.5	34.3	34.9



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(-5%)	4%
Low	30	(-30%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	92	78	83
to Sell	82	94	88
Hld's(000)	21830	24457	25874

% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.1	7.1
3 yr.	22.0	49.4
5 yr.	38.9	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
35.63	33.69	31.54	36.09	36.70	29.60	34.29	36.34	32.28	33.66	40.16	64.13	41.81	58.28	59.90	68.13	*76.90*	*78.75*	Revenues per sh A	*83.35*
3.74	3.73	3.67	3.85	3.99	3.68	4.98	4.92	4.44	4.74	5.58	5.84	5.59	5.88	5.32	5.31	*4.35*	*4.50*	"Cash Flow" per sh	*5.10*
2.07	2.05	2.06	2.11	2.13	1.78	2.96	2.81	2.25	2.39	2.71	3.16	2.80	2.88	2.18	2.26	*1.25*	*1.50*	Earnings per sh A B	*2.00*
1.65	1.71	1.76	1.78	1.80	1.80	1.82	1.87	1.91	1.95	2.00	2.04	2.07	2.12	2.16	2.18	*2.18*	*2.18*	Div'ds Decl'd per sh C ■	*2.18*
3.15	3.10	3.40	3.77	2.50	2.75	2.45	2.55	4.05	6.45	7.02	7.52	5.66	5.10	5.02	4.27	*8.95*	*6.90*	Cap'l Spending per sh	*7.15*
16.61	16.95	17.72	18.02	18.39	18.38	19.49	20.43	21.03	21.66	22.02	22.76	22.74	23.11	23.06	20.97	*19.60*	*18.40*	Book Value per sh D	*16.55*
32.70	32.76	34.77	34.88	34.87	34.91	34.96	35.07	35.26	35.49	35.30	35.40	35.46	36.69	37.73	38.16	*39.00*	*40.00*	Common Shs Outst'g E	*42.00*
11.2	11.8	13.1	15.0	13.3	14.7	10.7	12.7	16.2	15.5	12.1	12.3	13.3	13.4	19.1	18.9	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.0*
.83	.75	.79	.89	.87	.98	.67	.73	.84	.88	.79	.63	.73	.76	1.01	1.01	*estimates*		Relative P/E Ratio	*1.15*
7.1%	7.0%	6.5%	5.6%	6.3%	6.9%	5.7%	5.2%	5.2%	5.3%	6.1%	5.2%	5.5%	5.5%	5.2%	5.1%			Avg Ann'l Div'd Yield	*6.4%*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $1065.0 mill. Due in 5 Yrs $546.4 mill.
LT Debt $893.6 mill. LT Interest $60.0 mill.
(Total interest coverage: 1.8x)

Pension Assets-9/05 $520.4 mill. Oblig. $641.7 mill.

Pfd Stock None

Common Stock 38,471,441 shs. as of 7/31/06
MARKET CAP: $1.6 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
1198.7	1274.4	1138.1	1194.4	1417.5	2270.2	1482.5	2138.4	2260.2	2599.6	*3000*	*3150*	Revenues ($mill) A	*3500*
103.4	98.4	79.4	84.8	96.1	111.7	99.3	103.9	81.6	86.2	*50.0*	*60.0*	Net Profit ($mill)	*85.0*
37.6%	36.4%	36.2%	35.9%	34.1%	35.4%	34.2%	36.3%	31.7%	34.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
8.6%	7.7%	7.0%	7.1%	6.8%	4.9%	6.7%	4.9%	3.6%	3.3%	*1.6%*	*1.9%*	Net Profit Margin	*2.4%*
43.6%	42.4%	41.1%	40.4%	35.1%	44.4%	40.7%	46.7%	50.8%	52.8%	*53.9%*	*54.8%*	Long-Term Debt Ratio	*56.2%*
56.4%	57.6%	58.9%	59.6%	64.9%	55.6%	59.3%	53.3%	49.2%	47.2%	*46.1%*	*45.2%*	Common Equity Ratio	*43.8%*
1208.3	1243.5	1258.0	1290.5	1196.7	1449.8	1360.3	1592.3	1767.5	1695.7	*1660*	*1625*	Total Capital ($mill)	*1585*
1381.1	1402.2	1446.7	1519.8	1645.3	1753.9	1773.9	1838.2	1904.2	1947.3	*2150*	*2300*	Net Plant ($mill)	*2550*
10.3%	9.5%	7.8%	8.0%	9.5%	9.3%	8.4%	8.1%	6.0%	6.6%	*4.5%*	*5.5%*	Return on Total Cap'l	*7.0%*
15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	10.8%	*6.5%*	*8.0%*	Return on Shr. Equity	*12.0%*
15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	10.8%	*6.5%*	*8.0%*	Return on Com Equity	*12.0%*
5.9%	4.7%	1.7%	2.1%	3.4%	5.0%	3.3%	3.4%	.2%	.5%	*NMF*	*NMF*	Retained to Com Eq	*NMF*
61%	66%	84%	81%	73%	64%	73%	73%	97%	95%	*170%*	*145%*	All Div'ds to Net Prof	*106%*

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	21.1	43.5	157.0
Other	531.3	855.1	715.1
Current Assets	552.4	898.6	872.1
Accts Payable	144.7	236.2	198.5
Debt Due	55.6	8.1	171.4
Other	335.8	657.4	525.9
Current Liab.	536.1	901.7	895.8
Fix. Chg. Cov.	304%	332%	176%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	6.0%	12.0%	*5.0%*
"Cash Flow"	3.5%	2.0%	*NMF*
Earnings	2.0%	--	*NMF*
Dividends	2.0%	2.0%	*Nil*
Book Value	2.0%	0.5%	*NMF*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	549.2	903.8	398.1	287.3	2138.4
2004	604.9	927.0	401.1	327.2	2260.2
2005	737.4	1026.9	455.9	379.4	2599.6
2006	1052.4	1180.0	400.4	*367.2*	*3000*
2007	*1100*	*1225*	*425*	*400*	*3150*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.87	1.77	.22	.04	F 2.88
2004	.85	1.46	.15	d.27	F 2.18
2005	.77	1.37	.18	d.06	2.26
2006	.93	1.12	d.32	*d.48*	*1.25*
2007	*.95*	*1.15*	*d.20*	*d.40*	*1.50*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.51	.52	.52	.52	2.07
2003	.53	.53	.53	.53	2.12
2004	.54	.54	.54	.54	2.16
2005	.54	.545	.545	.545	2.18
2006	.545	.545	.545		

BUSINESS: Peoples Energy Corporation distributes natural gas via its utility subsidiaries, Peoples Gas Light & Coke Co. (approx. 814,000 customers at 9/30/05) and North Shore Gas Co. (155,000), in Chicago and northeastern Illinois. Fiscal 2005 gas distribution revenues: $1.7 billion: residential, 77%; commercial, 13%; industrial, 2%; other, 8%. Main supplier is Natural Gas Pipeline Co. of America. Purchased gas costs and revenue taxes accounted for 77% of gas revenues in fiscal '05. Depreciation rate: 3.5%. Est'd plant age: 11 years. Has 2,182 employees. Officers and Directors own 1.5% of common (1/06 Proxy). Chrmn. and CEO: Thomas Patrick. Inc.: IL. Address: 130 E. Randolph Dr., Chicago, IL 60601. Telephone: 312-240-4000. Internet: www.peoplesenergy.com.

Shares of Peoples Energy have increased by almost 12% since our last report, following the July announcement of a definitive merger agreement with WPS Resources. The deal was unanimously approved by the boards of directors of both companies. Each common share of Peoples Energy would be converted into .825 shares of WPS Resources stock. Using the recent closing price of WPS Resources, this would result in an approximate value of $41.32 per share for Peoples Energy stock. The acquisition, which will most likely occur in the first calendar quarter of 2007, is conditional upon shareholder and regulatory approvals. Upon completion, PGL shareholders would own about 42.4% of the new company.

The combined company will have about $9.2 billion in assets. It will operate natural gas and electric utilities in Wisconsin, Illinois, Michigan and Minnesota. The new company will likely pay a quarterly dividend of approximately $0.66 per share, the same payout Peoples Energy shareholders currently receive (factoring in the exchange ratio). WPS Resources CEO Larry Weyers will take the helm of the combined company. The board of directors will comprise nine members selected by WPS Resources and seven members selected by Peoples Energy.

Meanwhile, Peoples reported subpar results for the three-month period ended June 30th. Revenues declined by 12%, compared to the prior year. Warmer weather resulted in lower deliveries for the Gas distribution segment. Higher maintenance costs and depreciation expense also hindered the bottom line. The share loss was $0.32 for the second quarter. In addition, the company has lowered its share-net guidance for fiscal year 2006. We now expect share earnings of $1.25 for this period, a decline of roughly 45% from the prior year.

With a dividend yield of 5.3%, this stock may appeal to income-oriented accounts. The current quotation of PGL already reflects the price WPS Resources will likely pay for the company. Moreover, should the deal fall through, Peoples Energy shares could decline significantly. On PGL's own, appreciation potential to late decade is subpar.

Michael F. Napoli *September 15, 2006*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings per share. Excludes nonrecurring gains/(losses): '05, ($0.21). Next earnings report due late October.
(C) Dividends historically paid mid-January, April, July, October.
(D) Includes deferred charges. At 6/30/06: $46.1 mill., $1.19/sh.
(E) In millions. (F) Earnings don't sum due to change in shares outstanding.
(G) Suspended due to pending acquisition by WPS Resources.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE **25.29** | P/E RATIO **18.9** (Trailing: 18.2; Median: 17.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS **4** Raised 12/23/05
SAFETY **2** New 7/27/90
TECHNICAL **2** Raised 9/8/06
BETA .80 (1.00 = Market)

High:	12.4	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	26.2
Low:	9.1	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+60%)	15%
Low	30	(+20%)	8%

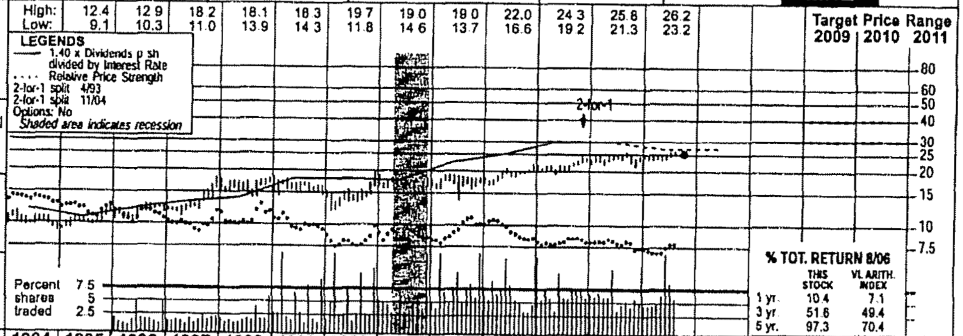
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	10	24	11	10	9	9	9	9	9
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	2	0	1	1	1	0	1

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	76	66	85
to Sell	77	71	81
Hld's(000)	30419	31060	32936

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 4/93
2-for-1 split 11/04
Options: No
Shaded area indicates recession



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.4	7.1
3 yr.	51.6	49.4
5 yr.	97.3	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
9.42	8.32	8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	16.14	19.95	22.96	*26.00*	*28.20*	Revenues per sh A	*33.10*
.97	.78	1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	*2.50*	*2.65*	"Cash Flow" per sh	*3.20*
.61	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	*1.30*	*1.40*	Earnings per sh B	*1.75*
.42	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	*.96*	*1.00*	Div'ds Decl'd per sh C■	*1.17*
1.62	1.37	1.41	1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	*2.65*	*2.40*	Cap'l Spending per sh	*2.20*
4.58	4.83	5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	*10.85*	*11.35*	Book Value per sh D	*12.75*
42.87	49.46	51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	*75.00*	*74.50*	Common Shs Outst'g E	*72.50*
11.3	16.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	Bold figures are	Value Line	Avg Ann'l P/E Ratio	*19.0*
.84	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	estimates		Relative P/E Ratio	*1.25*
6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%			Avg Ann'l Div'd Yield	*3.5%*
						685.1	775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	*1950*	*2100*	Revenues ($mill) A	*2400*
						48.6	55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	*100*	*105*	Net Profit ($mill)	*130*
						38.9%	39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	*35.0%*	*36.0%*	Income Tax Rate	*36.0%*
						7.1%	7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	*5.1%*	*5.1%*	Net Profit Margin	*5.3%*
						50.3%	47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	*43.5%*	*42.5%*	Long-Term Debt Ratio	*42.0%*
						49.7%	52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	*56.5%*	*57.5%*	Common Equity Ratio	*58.0%*
						777.1	800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	*1440*	*1470*	Total Capital ($mill)	*1600*
						862.0	941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	*2040*	*2170*	Net Plant ($mill)	*2400*
						8.2%	8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	*8.5%*	*8.5%*	Return on Total Cap'l	*9.0%*
						12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*12.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
						12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*12.0%*	*12.5%*	Return on Com Equity	*13.0%*
						3.9%	4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
						69%	65%	65%	72%	71%	75%	83%	74%	66%	68%	*72%*	*70%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 4/30/06
Total Debt $912.0 mill. **Due in 5 Yrs** $325.0 mill
LT Debt $625.0 mill. **LT Interest** $40.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)

Pension Assets-10/05 $199.2 mill. Oblig. $236.6 mill.

Pfd Stock None

Common Stock 75,277,520 shs. as of 6/2/06

MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	4/30/06
Cash Assets	5.7	7.1	20.3
Other	329.5	497.8	431.7
Current Assets	335.2	504.9	452.0
Accts Payable	99.6	182.8	73.7
Debt Due	109.5	193.5	287.0
Other	97.1	152.3	123.0
Current Liab.	306.2	528.6	483.7
Fix. Chg. Cov.	378%	400%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	11.0%	*8.5%*
"Cash Flow"	7.0%	5.5%	*6.0%*
Earnings	5.5%	5.0%	*6.0%*
Dividends	5.5%	5.0%	*5.5%*
Book Value	6.5%	6.5%	*3.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	493.5	407.8	140.1	179.4	1220.8
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	*307.5*	*1950*
2007	*875*	*565*	*315*	*345*	*2100*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	.87	.47	d.15	d.08	1.11
2004	1.03	.54	d.11	d.21	1.27
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	*d.05*	*1.30*
2007	*.98*	*.57*	*d.06*	*d.09*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.193	.20	.20	.20	.79
2003	.20	.208	.208	.208	.82
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24		

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 990,000 customers in North Carolina, South Carolina, and Tennessee. 2005 revenue mix: residential (39%), commercial (24%), industrial (13%), other (24%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 71.6% of revenues. '05 deprec. rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,125 employees. Officers & directors own less than 1% of common stock (1/06 proxy). CEO & President: Thomas E. Skains. Inc.: NC. Addr.: 1915 Rexford Road, P.O. Box 33068 Charlotte, NC 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas posted a larger share loss than we had anticipated. The fiscal third quarter (ended July 31st) was impacted by reduced margins due to rate design changes, and costs associated with the company's corporate restructuring program. In July, Piedmont and North Carolina's Attorney General office reached a settlement on its customer utilization tracker rate mechanism, which decouples the collection of utility margin from customer volume. This plan is favorable for both customers, who will benefit by the more efficient use of natural gas, and Piedmont shareholders, who will not suffer the negative consequences of conservation by customers. As part of the agreement, the company will fund up to $1.5 million annually over the next few years toward customer conservation programs, in addition to the $500,000 it had already committed to spend. Furthermore, Piedmont's initial restructuring involved offering early retirement to management-level employees and will eventually include other positions as part of an effort to streamline business processes and improve corporate efficiencies. The company should realize about $5 million to $6 million in annual cost savings beginning in 2007.

The company's nonutility operations will likely represent a greater percentage of future profits. Over the first six months of 2006, these activities contributed earnings of $25.5 million, which is nearly 20% above the year-ago period. Even though regulated operations make up most of Piedmont's total income, unregulated operations such as Cardinal Pipeline, Pine Needle, and SouthStar Energy provide an added boost to the company's bottom line. We expect Piedmont to continue to pursue strategic investments to diversify its earnings stream over the next few years.

Though untimely, this stock is suitable for conservative income-oriented investors. Piedmont offers a respectable dividend yield at 3.9% and has an Above Average Safety rank (2). Moreover, the company should benefit as it diversifies its supply portfolio away from the Gulf Coast region through agreements with Midwestern Gas Transmission Company and Hardy Storage Company.

Evan I. Blatter *September 15, 2006*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due mid-Dec.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. At 10/31/05: $4.0 million, 5¢/share.
(E) In millions, adjusted for stock splits.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	80

RGC RESOURCES INC NDQ–RGCO

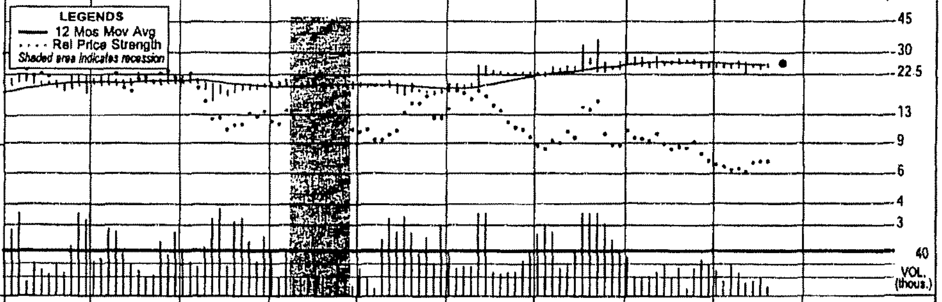
RECENT PRICE 25.96 | TRAILING P/E RATIO 17.5 | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.6% | VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	22.75	23.25	22.50	21.25	20.75	25.50	35.75	29.55	26.90	High
Low	17.50	19.25	15.81	18.22	16.99	17.86	21.79	24.50	22.72	Low

RANKS

PERFORMANCE 3 Average
Technical 3 Average
SAFETY 3 Average
BETA .40 (1.00 = Market)

Financial Strength B+
Price Stability 90
Price Growth Persistence 60
Earnings Predictability 50



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	33.10	31.15	41.32	61.34	40.92	52.10	49.94	57.96	–	
"CASH FLOW" PER SH	3.09	3.82	3.94	3.80	3.97	4.47	3.00	3.65	–	
EARNINGS PER SH	1.60	1.59	1.54	1.21	1.28	1.77	1.01	1.62	NA	NA/NA
DIV'DS DECL'D PER SH	1.06	1.08	1.10	1.12	1.14	1.14	1.17	1.18	--	
CAP'L SPENDING PER SH	5.15	4.88	4.21	4.19	4.39	4.17	3.84	3.54	–	
BOOK VALUE PER SH	14.75	15.36	15.94	16.05	16.36	16.90	17.73	18.18	--	
COMMON SHS OUTST'G (MILL)	1.79	1.83	1.88	1.91	1.96	2.00	2.07	2.10	–	
AVG ANN'L P/E RATIO	12.4	12.9	12.8	16.2	15.0	11.5	24.0	16.2	NA	NA/NA
RELATIVE P/E RATIO	.64	.74	.83	.83	.82	.66	1.27	.86	–	
AVG ANN'L DIV'D YIELD	5.3%	5.3%	5.6%	5.7%	5.9%	5.6%	4.8%	4.5%	–	
SALES ($MILL)	59.4	57.1	77.8	117.4	80.2	104.4	103.1	121.6	--	*Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.*
OPERATING MARGIN	14.5%	18.0%	14.7%	12.6%	16.2%	14.5%	10.5%	11.0%	–	
DEPRECIATION ($MILL)	2.8	4.1	4.5	5.0	5.3	5.4	4.1	4.3	–	
NET PROFIT ($MILL)	2.7	2.9	2.9	2.3	2.5	3.5	2.1	3.4	–	
INCOME TAX RATE	29.5%	31.9%	34.6%	40.3%	37.9%	37.8%	37.2%	37.6%	–	
NET PROFIT MARGIN	4.6%	5.0%	3.7%	2.0%	3.1%	3.4%	2.0%	2.8%	–	
WORKING CAP'L ($MILL)	d3.9	d4.2	d6.3	d8.2	d1.6	d3.0	3.0	6.4	–	
LONG-TERM DEBT ($MILL)	20.7	23.3	23.3	22.5	30.4	30.2	26.0	30.0	–	
SHR. EQUITY ($MILL)	26.5	28.2	30.0	30.7	32.1	33.9	36.6	38.2	–	
RETURN ON TOTAL CAP'L	7.4%	7.1%	7.7%	5.8%	5.3%	6.7%	4.3%	6.2%	–	
RETURN ON SHR. EQUITY	10.3%	10.2%	9.6%	7.5%	7.8%	10.4%	5.6%	8.9%	–	
RETAINED TO COM EQ	3.7%	3.3%	2.8%	.6%	.9%	3.8%	NMF	8.9%	–	
ALL DIV'DS TO NET PROF	64%	68%	71%	92%	88%	64%	113%	–	–	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	8.5%	16.0%
"Cash Flow"	0.5%	22.0%
Earnings	-1.5%	60.5%
Dividends	1.5%	1.0%
Book Value	3.0%	2.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
09/30/04	29.9	39.7	18.2	15.3	103.1
09/30/05	34.7	43.3	20.8	22.8	121.6
09/30/06	52.8	45.8	13.0		
09/30/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
09/30/03	.78	1.58	d.28	d.31	1.77
09/30/04	.57	.93	d.13	d.36	1.01
09/30/05	.77	.99	.06	d.20	1.62
09/30/06	.69	1.02	d.03		
09/30/07					

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.285	.285	.285	.285	1.14
2004	.285	.295	.295	.295	1.17
2005	.295	.295	.295	.295	1.18
2006	.30	.30	.30		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	4	6	5
to Sell	3	6	2
Hld's(000)	233	238	247

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	14.5	1.4	4.9
Receivables	6.6	9.7	7.1
Inventory (Avg cost)	2.5	24.2	18.6
Other	20.2	3.7	5.1
Current Assets	43.8	39.0	35.7
Property, Plant & Equip, at cost	105.3	109.5	--
Accum Depreciation	34.7	35.4	--
Net Property	70.6	74.1	77.0
Other	.6	.5	.5
Total Assets	115.0	113.6	113.2
LIABILITIES ($mill.)			
Accts Payable	10.7	19.1	14.9
Debt Due	12.8	7.7	2.7
Other	17.2	5.9	10.6
Current Liab	40.7	32.7	28.2

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $32.7 mill. Due in 5 Yrs. NA
LT Debt $30.0 mill.
Including Cap. Leases NA
(42% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '05 vs None in '04

Pfd Stock None Pfd Div'd Paid None

Common Stock 2,130,573 shares
(58% of Cap'l)

INDUSTRY: Natural Gas (Distrib.)

BUSINESS: RGC Resources Inc. engages in the regulated sale and distribution of natural gas to approximately 59,000 residential, commercial, and industrial customers in Roanoke, Virginia, and Bluefield, Virginia, and West Virginia, as well as the surrounding areas through its Roanoke Gas Company and Bluefield Gas Company subsidiaries. Roanoke Gas and Bluefield Gas hold the only franchises and/or certificates of public convenience and necessity to distribute natural gas in its Virginia and West Virginia service areas. RGC also provides information system services to software providers in the utility industry through a subsidiary, RGC Ventures, Inc. of Virginia, which operates as Application Resources. Has 137 employees. Chairman, C.E.O. & President: John B. Williamson III. Inc.: VA. Address: 519 Kimball Avenue, N.E., Roanoke, VA 24016. Tel.: (540) 777-4427. Internet: http://www.rgcresources.com.

A.O.

September 15, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 8/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
3.46%	7.91%	-0.31%	29.53%	73.79%

o

SEMCO ENERGY NYSE-SEN

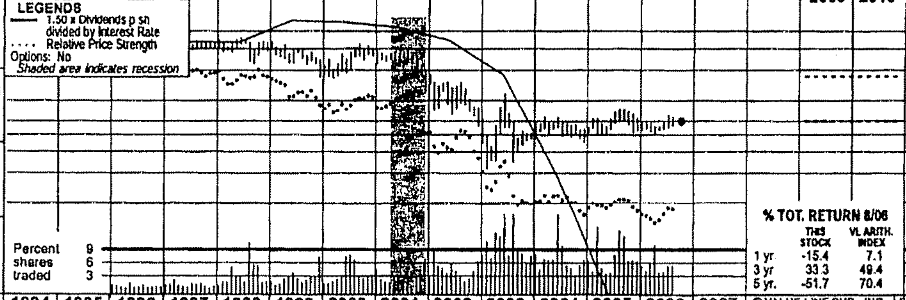
RECENT PRICE	5.99	P/E RATIO	20.0 (Trailing: 46.1 Median: 23.0)	RELATIVE P/E RATIO	1.18	DIV'D YLD	Nil	VALUE LINE

TIMELINESS 3 Lowered 1/13/06
SAFETY 4 Lowered 12/17/04
TECHNICAL 2 Raised 8/25/06
BETA .80 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	17.5	17.5	19.3	18.4	17.5	16.9	15.8	11.4	8.8	6.4	7.1	6.5
Low:	14.0	13.5	15.7	13.1	10.9	10.8	8.9	5.6	3.2	4.5	5.0	5.0

Target Price Range 2009 | 2010 | 2011

LEGENDS
—— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	11	(+85%)	16%
Low	6	(Nil)	Nil

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	31	28	30
to Sell	22	25	22
Hld's(000)	22501	21575	22128

Percent shares traded 9 6 3

% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.4	7.1
3 yr.	33.3	49.4
5 yr.	-51.7	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
20.04	19.84	20.97	23.39	27.21	24.49	40.06	55.56	36.67	21.48	23.41	24.28	25.53	19.44	17.90	18.25	*17.35*	*15.50*	Revenues per sh	*14.20*
1.43	1.65	1.78	1.77	1.67	1.71	1.71	1.63	1.39	2.06	2.78	1.98	2.35	1.37	1.12	1.12	*1.10*	*1.25*	"Cash Flow" per sh	*1.40*
.59	.63	.78	.78	.84	.83	.88	.71	55	.96	.90	d.01	.48	.14	.12	.26	*.25*	*.35*	Earnings per sh A	*.65*
.53	.55	.58	.61	.62	.67	.71	.74	.74	.81	.84	.84	.59	.35	.08	--	*Nil*	*Nil*	Div'ds Decl'd per sh B	*Nil*
1.40	2.53	2.10	1.83	1.49	1.92	2.21	2.12	1.45	1.96	3.69	3.02	1.86	1.08	1.37	1.19	*1.20*	*1.15*	Cap'l Spending per sh	*.95*
5.86	6.08	6.47	6.93	7.85	7.99	6.61	6.82	7.61	7.95	7.50	6.20	5.84	6.22	5.79	5.65	*5.90*	*6.35*	Book Value per sh C	*7.90*
11.40	11.67	12.00	12.35	13.69	13.70	13.67	13.86	17.38	17.91	18.06	18.36	18.84	28.06	28.40	33.70	*35.50*	*35.50*	Common Shs Outst'g D	*45.00*
18.4	17.3	16.1	21.4	18.3	19.3	17.7	23.8	29.7	15.3	15.3	--	17.7	36.5	45.5	22.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
1.37	1.11	.98	1.26	1.20	1.29	1.11	1.37	1.54	.87	.99	--	.97	2.08	2.40	1.22	*Value Line*		Relative P/E Ratio	*.85*
4.9%	5.1%	4.7%	3.6%	4.0%	4.2%	4.5%	4.4%	4.5%	5.5%	6.1%	6.1%	7.0%	6.8%	1.5%	--	*estimates*		Avg Ann'l Div'd Yield	*Nil*

CAPITAL STRUCTURE as of 6/30/06
Total Debt $472.8 mill. Due in 5 Yrs $263.9 mill.
LT Debt $441.6 mill. LT Interest $38.0 mill.

(Total interest coverage: 1.4x)

Leases, Uncapitalized Annual rentals $1.9 mill.
Pension Assets-12/05 $70 mill. Oblig. $94 mill.

Pfd Stock $47.8 mill. Pfd Div'd $2.4 mill.
239,216 shs., 5% cum., liqu. val. $200, ea. convertible into common stock at a conversion price of $7.65 per share.
Common Stock 35,381,479 shs.
MARKET CAP: $200 million (Small Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
547.6	770.3	637.5	384.8	422.6	445.8	481.0	545.4	508.3	615.1	*615*	*550*	Revenues ($mill)	*640*
12.0	9.9	9.0	17.0	16.7	d.2	8.9	3.0	4.2	11.7	*10.0*	*14.0*	Net Profit ($mill)	*28.0*
34.7%	36.2%	41.4%	28.0%	34.8%	NMF	38.1%	35.6%	--	33.9%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.2%	1.3%	1.4%	4.4%	4.0%	NMF	1.9%	.6%	.8%	1.9%	*1.6%*	*2.5%*	Net Profit Margin	*4.4%*
54.1%	62.6%	55.7%	54.4%	76.8%	80.8%	82.1%	75.2%	69.3%	62.9%	*63.0%*	*61.5%*	Long-Term Debt Ratio	*54.0%*
45.9%	36.2%	43.3%	45.6%	23.2%	19.2%	17.9%	24.8%	23.6%	27.1%	*30.0%*	*31.5%*	Common Equity Ratio	*46.0%*
197.0	261.3	305.5	312.3	582.8	592.2	615.5	703.4	697.8	702.2	*700*	*715*	Total Capital ($mill)	*775*
246.4	257.2	290.2	474.3	510.0	524.5	521.1	562.5	559.7	577.4	*585*	*600*	Net Plant ($mill)	*645*
8.3%	5.6%	5.4%	7.5%	5.4%	2.9%	4.3%	2.8%	3.6%	4.7%	*4.5%*	*3.5%*	Return on Total Cap'l	*6.0%*
13.3%	10.1%	6.6%	11.9%	12.3%	NMF	8.1%	1.7%	1.9%	4.5%	*4.0%*	*5.0%*	Return on Shr. Equity	*8.0%*
13.3%	10.3%	6.6%	11.9%	12.3%	NMF	8.1%	1.7%	2.5%	4.9%	*5.0%*	*6.0%*	Return on Com Equity	*8.0%*
2.4%	NMF	NMF	1.1%	1.2%	NMF	NMF	NMF	NMF	4.9%	*3.5%*	*5.0%*	Retained to Com Eq	*8.0%*
82%	105%	NMF	91%	90%	NMF	121%	NMF	102%	20%	*27%*	*17%*	All Div'ds to Net Prof	*Nil*

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	3.7	5.7	5.3
Other	182.7	257.0	152.4
Current Assets	186.4	262.7	157.7
Accts Payable	29.3	64.6	19.7
Debt Due	54.4	78.9	31.2
Other	43.4	54.8	42.6
Current Liab.	127.1	198.3	93.5
Fix. Chg. Cov	122%	125%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	-3.0%	-7.5%	*NMF*
"Cash Flow"	-3.5%	-10.5%	*2.5%*
Earnings	-14.5%	-26.5%	*24.5%*
Dividends	-14.0%	-29.0%	*NMF*
Book Value	-2.5%	-5.0%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	207.6	100.5	74.2	163.1	545.4
2004	207.8	81.8	54.0	164.7	508.3
2005	226.6	95.6	62.3	230.6	615.1
2006	271.5	97.0	*65.0*	*196.5*	*615*
2007	*215*	*100*	*60.0*	*175*	*550*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.57	d.27	d.32	.16	.14
2004	.45	d.13	d.26	.06	.12
2005	.38	d.11	d.29	.22	.26
2006	.30	d.10	*d.25*	*.30*	*.25*
2007	*.35*	*d.10*	*d.25*	*.35*	*.35*

Calendar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.21	.125	.125	.125	.59
2003	.125	.125	.075	.075	.40
2004	.075	.075	--	--	.15
2005	--	--	--	--	--
2006	--	--			

BUSINESS: SEMCO Energy, Inc. distributes natural gas to about 409,000 customers in Michigan and Alaska. Residential (62% of total sales). Other businesses include information technology services, propane distribution, and natural gas pipeline and storage. Construction Services business discontinued in 2003. Sold energy marketing business in 3/99. Divested NOARK, 1/98. Acquired Hotflame Transport, 3/98; Enstar, 11/99. 2005 depreciation rate: 3.6%. Has about 566 employees. Off./dir. own 2.2% of common stock; FMR Corp., 10.0%; National City Corp., 9.7% (4/06 proxy). Chairman: Dr. John M. Albertine. President & CEO: George Schreiber, Jr. Inc.: MI. Address: 405 Water Street, Port Huron, MI 48060. Telephone: 810-987-2200. Internet: www.semcoenergy.com.

SEMCO Energy has been hurt by weather and customer conservation trends. Unseasonably warmer temperatures in Michigan have contributed to a decline in gas consumption. To make matters worse, higher natural gas prices seem to have prompted a greater number of customers in both Michigan and Alaska to step up their conservation efforts. These unforeseen setbacks probably decreased net income by $3.1 million in the first half of 2006. We assume that weather conditions will return to normal through the balance of the year, but the company is still faced with several challenges on the operating front.

There is a good argument for rate relief, in our view. Indeed, further increases in customers' conservation habits may put greater stress on the company's already weak finances. Mounting operating and maintenance expenses (higher employee benefit costs and delinquent accounts) are taking a toll on the bottom line. Under such conditions, it is not likely that SEMCO will be able to achieve its allowed rate of return of 11.0%. That said, a request with the Michigan Public Service Commission was filed in late May for an $18.9 million increase in base rates. Hearings are scheduled to begin in December, but the decision process is typically time consuming, taking between nine-12 months. An early settlement should not be ruled out, but this would likely be at the cost of a reduced rate hike.

Our 2007 sales and earnings estimates are tentative, at best. Assuming normal weather conditions through next year, profits should rebound. The timing of the aforementioned rate decision is difficult to predict, but there is upside potential should a rate hike be awarded.

Most investors should avoid these shares at this time. Although we believe that the company will receive rate relief, the amount that regulators will allow is uncertain. The worst appears to be over for SEMCO, but it's still too early to get on board here.

Charles W. Noh *September 15, 2006*

CASH POSITION	5-Year Av'g	6/30/06
Current Assets to Current Liabilities:	79.6%	169%
Cash & Equiv's to Current Liabilities:	1.7%	6%
Working Capital to Sales:	NMF	10%

(A) Diluted egs. Excludes nonrecurring gain/(loss): '98, 8¢; '99, 4¢; '01, (34¢); '03, ($1.48); '05, ($0.27); '06, ($0.02). Excludes gain/(loss) from discontinued operations: '04, ($0.28); '05, $0.02. Next earnings report due early Nov. Quarterly figures may not sum to total due to rounding or change in share count (antidilution). (B) Dividends on common stock suspended as of 6/04. (C) Includes intangibles; '05: $143.4 mill., $4.26/sh. (D) In millions.

Company's Financial Strength	C+
Stock's Price Stability	25
Price Growth Persistence	5
Earnings Predictability	35

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 28.80 | P/E RATIO 15.2 (Trailing: 17.2 Median: 14.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 5 Lowered 4/7/06
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Raised 7/21/06
BETA .70 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+40%)	11%
Low	30	(+5%)	4%

Insider Decisions

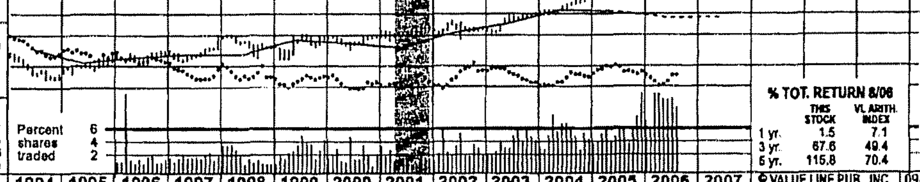
	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	3	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	63	58	64
to Sell	49	52	46
Hld's(000)	14085	14260	15700

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	11.8	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	30.2
Low:	8.9	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6

Target Price Range 2009 | 2010 | 2011



% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.5	7.1
3 yr.	67.6	49.4
5 yr.	115.8	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
14.40	15.10	16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	32.90	34.10	Revenues per sh	38.25
1.34	1.37	1.56	1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	2.80	3.00	"Cash Flow" per sh	3.50
.67	.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	1.85	1.95	Earnings per sh A	2.35
.70	.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	.96	Div'ds Decl'd per sh B ■	1.15
2.11	2.17	1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	3.60	3.70	Cap'l Spending per sh	4.05
6.79	6.77	6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	14.30	15.10	Book Value per sh C	17.55
18.06	18.48	19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.20	29.60	Common Shs Outst'g D	31.00
13.6	14.5	13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	Bold figures are		Avg Ann'l P/E Ratio	14.0
1.01	.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	Value Line		Relative P/E Ratio	.95
7.7%	7.6%	6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 6/30/06
Total Debt $505.1 mill. Due in 5 Yrs $175.0 mill.
LT Debt $358.1 mill. LT Interest $20.0 mill.
(Total interest coverage: 4.8x)

Pension Assets-12/05 $108.5 mill. Oblig. $126.7 mill.

Pfd Stock none

Common Stock 29,232,801 common shs. as of 8/1/06

MARKET CAP: $850 milllon (Small Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
355.5	348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	921.0	960	1010	Revenues ($mill)	1185
18.5	18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	55.0	60.0	Net Profit ($mill)	70.0
35.5%	36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	40.5%	40.5%	Income Tax Rate	40.5%
5.2%	5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	5.6%	5.6%	Net Profit Margin	6.0%
46.1%	54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	43.0%	43.0%	Long-Term Debt Ratio	40.0%
53.2%	35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	57.0%	57.0%	Common Equity Ratio	60.0%
324.8	387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	710.3	735	780	Total Capital ($mill)	895
423.9	456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	877.3	940	1010	Net Plant ($mill)	1200
7.9%	8.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	8.5%	8.5%	Return on Total Cap'l	9.0%
10.5%	10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	13.0%	13.0%	Return on Shr. Equity	13.0%
10.6%	13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	13.0%	13.0%	Return on Com Equity	13.0%
1.6%	2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	6.5%	6.5%	Retained to Com Eq	6.5%
85%	84%	112%	72%	67%	76%	62%	57%	52%	50%	50%	50%	All Div'ds to Net Prof	52%

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	10.6	4.9	6.9
Other	273.3	352.6	288.9
Current Assets	283.9	357.5	295.8
Accts Payable	118.8	179.0	74.8
Debt Due	97.6	149.7	147.0
Other	68.9	74.4	105.2
Current Liab.	285.3	403.1	327.0
Fix. Chg. Cov.	426%	486%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	5.5%	7.5%	4.5%
"Cash Flow"	4.5%	6.5%	6.5%
Earnings	8.0%	11.5%	7.0%
Dividends	1.5%	2.5%	6.0%
Book Value	5.5%	13.0%	6.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	279.9	106.2	90.1	220.6	696.8
2004	307.6	136.5	129.5	245.5	819.1
2005	328.6	154.0	157.0	281.4	921.0
2006	365.0	155.5	162	277.5	960
2007	375	175	172	288	1010

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.92	.08	d.07	.44	1.37
2004	.91	.15	.02	.50	1.58
2005	.96	.27	.09	.39	1.71
2006	.93	.25	.14	.53	1.85
2007	.98	.30	.12	.55	1.95

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.185	.188	.188	.38	.94
2003	--	.193	.193	.395	.78
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	.225	.225		

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 322,424 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '05: residential, 45%; commercial, 23%; cogeneration and electric generation 4%; industrial, 23%. Non-utility operations include: South Jersey Energy, South Jersey Resource Group, Marina Energy, and South Jersey Energy Services Plus. Has 636 employees. Off./dir. cntrl. 1.5% of com. shares; Dimensional Fund Advisors, 7.9%; Barclays, 5.3% (3/06 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Rte. 54, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries' earnings comparisons have been weak over the first six months of 2006. This is largely due to warmer than normal temperatures and conservation by customers as a result of high natural gas prices. On the positive side, there is continued optimism that the company's conservation and usage adjustment proposal will be approved by the New Jersey Board of Public Utilities and be in place by next winter's heating season. Moreover, the utility added 8,740 customers during the past 12 months, which represents nearly a 3% increase over the prior year. Due to the strength of the local economy and demand for housing in the region, the company should add customers at a rate exceeding the industry average over the next few years. For 2006, we look for earnings to advance about 8%, to $1.85, due to a pickup in nonregulated activities, followed by a more sustainable 6%–7% rate out to late decade.

Marina Energy still has room for growth. It recently completed the expansion of its Atlantic City thermal plant to support the 500,000-square-foot expansion to the gaming area at the Borgata Hotel Casino & Spa. Results should be further enhanced toward the end of next year when an 800-room tower is completed at the Borgata. Also, Marina is in the process of completing a 3.8 megawatt methane-to-electric generation project at the Warren County district landfill, which should provide additional opportunities for growth. Looking ahead, the subsidiary may be able to benefit should a casino/hotel be built on a 50-acre property owned by MGM that is located next to the Borgata.

After a slow start to the year, the Residential & Commercial Service business may exceed its 2005 performance going forward. This is primarily due to recent additions to its portfolio of services that include propane heaters and appliances, and small commercial heating, ventilating, and air conditioning systems.

This untimely stock is best suited for investors seeking moderate yield and good dividend growth potential. Over the 2009–2011 period, we look for steady dividend increases, which should push the yield to around 3.5%, along with a slight reduction in the debt-to-equity ratio.

Evan I. Blatter *September 15, 2006*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02). Excl. gains due to acct'g change: '93, $0.04; '01, $0.14. Next egs report due late Oct.
(B) Dividends paid early Apr., Jul., Oct, and late Dec. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets ($121.5 mill.): at 12/31/05, $4.19 per shr.
(D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	90

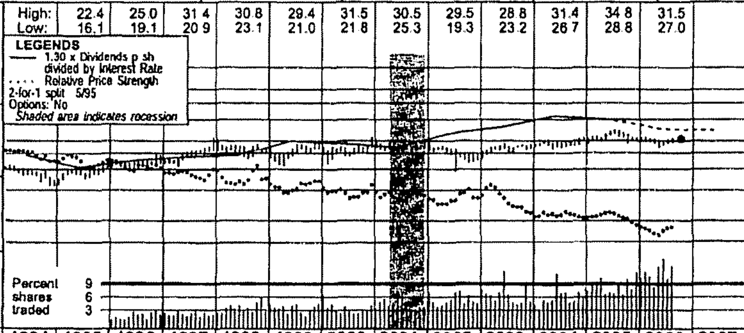
WGL HOLDINGS NYSE-WGL

RECENT PRICE 30.77 | P/E RATIO 14.4 (Trailing: 17.1; Median: 15.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 4 Raised 8/4/06
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Raised 5/26/06
BETA .80 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	31.5
Low:	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/95
Options: No
Shaded area indicates recession



Target Price Range 2009 | 2010 | 2011

80
60
50
40
30
25
20
15
10
7.5

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+15%)	7%
Low	30	(-5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	88	70	73
to Sell	67	77	78
Hld's(000)	27959	27311	29760

Percent shares traded 9 6 3

% TOT. RETURN 8/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	-1.2	7.1
3 yr.	32.0	49.4
5 yr.	44.8	70.4

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
18.75	17.50	18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	**53.80**	**55.40**	Revenues per sh A	**61.50**
2.17	2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	**3.75**	**3.90**	"Cash Flow" per sh	**4.50**
1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	**1.85**	**1.95**	Earnings per sh B	**2.35**
1.01	1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	**1.35**	**1.38**	Div'ds Decl'd per sh C■	**1.48**
2.38	2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	**3.40**	**3.30**	Cap'l Spending per sh	**4.00**
10.17	9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	**17.85**	**18.60**	Book Value per sh D	**21.15**
39.23	39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	**48.70**	**48.70**	Common Shs Outst'g E	**48.80**
11.7	12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**14.0**
.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	*estimates*		Relative P/E Ratio	**.90**
6.9%	7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%			Avg Ann'l Div'd Yield	**4.3%**

CAPITAL STRUCTURE as of 6/30/06
Total Debt $726.8 mill. Due in 5 Yrs $520.0 mill.
LT Debt $581.8 mill. LT Interest $40.0 mill.
(LT interest earned: 4.6x; total interest coverage: 4.2x)
Pension Assets-9/05 $691.7 mill. Oblig. $691.2 mill.
Preferred Stock $28.2 mill. Pfd Div'd $1.3 mill.

Common Stock 48,773,729 shs. as of 7/31/06

MARKET CAP: $1.5 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	**2620**	**2700**	Revenues ($mill) A	**3000**
81.6	82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	**90.0**	**95.0**	Net Profit ($mill)	**115**
37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	**38.0%**	**38.0%**	Income Tax Rate	**38.0%**
8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	**3.5%**	**3.6%**	Net Profit Margin	**3.8%**
37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	**39.0%**	**39.0%**	Long-Term Debt Ratio	**39.0%**
59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	**59.0%**	**59.0%**	Common Equity Ratio	**59.0%**
941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	**1515**	**1575**	Total Capital ($mill)	**1780**
1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	**2120**	**2270**	Net Plant ($mill)	**2550**
10.1%	9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.5%**
14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	**10.0%**	**10.0%**	Return on Com Equity	**11.0%**
5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	**2.5%**	**3.0%**	Retained to Com Eq	**4.0%**
62%	63%	78%	82%	69%	67%	112%	56%	65%	62%	**74%**	**72%**	All Div'ds to Net Prof	**64%**

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	6.6	4.8	88.1
Other	426.3	476.2	454.3
Current Assets	432.9	481.0	542.4
Accts Payable	179.0	204.9	172.4
Debt Due	156.3	91.0	145.0
Other	77.6	115.5	147.8
Current Liab.	412.9	411.4	465.2
Fix. Chg. Cov.	449%	460%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	14.5%	6.0%
"Cash Flow"	5.0%	6.5%	2.0%
Earnings	4.5%	6.0%	1.5%
Dividends	1.5%	1.5%	2.0%
Book Value	4.0%	3.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	560.0	851.1	373.2	278.9	2064.2
2004	585.3	862.2	356.9	285.2	2089.6
2005	623.4	929.8	349.0	284.1	2186.3
2006	909.3	1070.4	346.9	*293.4*	*2620*
2007	*960*	*1010*	*380*	*350*	*2700*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.91	1.16	d.01	*d.21*	*1.85*
2007	*.95*	*1.40*	*d.15*	*d.25*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.318	.318	.318	1.27
2002	318	.32	.32	.32	1.28
2003	.32	.325	.325	.325	1.30
2004	.325	.333	.333	.333	1.32
2005	.333	.338	.338		

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA. and MD. to resident'l and comm'l users (1,032,198 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 9.3% of common stock; Off./dir. less than 1% (1/06 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted solid results in the seasonally weak fiscal third quarter (ended June 30th). It reported a share net loss of $0.01, which excluded the results from the recently sold American Combustion Industries subsidiary, significantly ahead of last year's figure. The results were driven by lower operation and maintenance expense, utility customer growth, and improved performance at the retail energy-marketing business. In fact, income from this segment nearly doubled from the year-ago period, to $6.1 million, thanks to higher gross margins from the sale of natural gas and electricity. This should help push nonutility earnings to about $0.21 a share this year, with additional improvements likely in 2007.

WGL expects to file a pair of rate increases. One will soon be with the Virginia State Corporation Commission, and another with the Maryland Public Service Commission next spring. The primary need for the Maryland rate increase is to recover costs associated with the Prince George's County rehabilitation program. The project is scheduled to be completed in 2008 at a $144 million price tag. If this project is fully recovered through a rate increase, which is probable, WGL should realize a $0.16-a-share boost to earnings.

The company is slated to spend about $855 million on capital improvement projects out to 2010. WGL expects to begin construction on its LNG storage facility in late 2008 pending regulatory approval, two years later than previously anticipated due to zoning and other legal challenges, and scheduled to be completed by the 2011-2012 winter. However, until approval is granted WGL will explore other opportunities to meet its peak day requirements to serve its customers.

These shares are best suited for conservative investors. The dividend yield stands at 4.5%, above the industry average, while the stock's Safety rank is 1 (Highest). Long term, we look for Washington Gas to add about 25,000–30,000 new utility customers annually, thanks to the new home construction expected in its service areas over the next 20 years. The stock, which is not well ranked for performance is dependable for income. But its price range only inches up over time.

Evan I. Blatter *September 15, 2006*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); discontinued operations: '06, (3¢).
Next earnings report due early Nov.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '05: $150.0 million, $3.08/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

AMERICAN DENTAL NDQ–ADPI

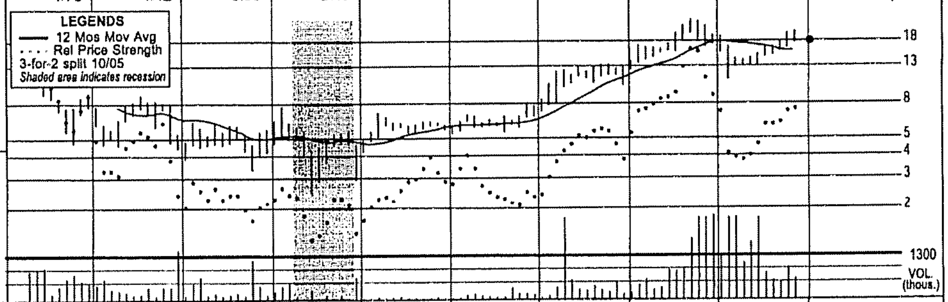
RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
17.99	20.7	1.03	Nil	

High	12.92	8.92	6.25	7.67	7.00	7.97	13.39	23.71	20.45	High
Low	4.75	4.42	3.33	2.49	4.20	5.33	7.08	12.36	10.84	Low

RANKS

PERFORMANCE	1	Highest
Technical	1	Highest
SAFETY	3	Average
BETA .50		(1.00 = Market)

Financial Strength	B+
Price Stability	35
Price Growth Persistence	85
Earnings Predictability	70



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	7.54	11.01	12.90	13.70	13.49	14.84	15.10	16.07	--	
"CASH FLOW" PER SH	.57	1.15	1.28	1.14	1.26	1.43	1.59	1.82	--	
EARNINGS PER SH	.36	.52	.56	.30	.42	.55	.71	.81	***.88***[A,B]	***1.02***[C]***/NA***
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	.45	1.17	.84	.63	.52	.67	.82	.90	--	
BOOK VALUE PER SH	4.33	4.90	5.25	5.74	6.15	6.70	7.37	8.31	--	
COMMON SHS OUTST'G (MILL)	11.15	10.66	11.13	10.76	10.88	11.03	11.83	12.26	--	
AVG ANN'L P/E RATIO	NMF	12.6	8.9	16.4	13.7	11.5	15.8	21.7	***20.4***	***17.6/NA***
RELATIVE P/E RATIO	NMF	.72	.58	.84	.75	.66	.83	1.15	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	84.1	117.4	143.6	147.4	146.8	163.7	178.6	196.9	--	***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.***
OPERATING MARGIN	11.8%	15.9%	16.2%	21.7%	22.3%	22.8%	14.6%	15.6%	--	
DEPRECIATION ($MILL)	2.5	6.2	8.1	9.0	9.0	9.6	10.3	12.0	--	
NET PROFIT ($MILL)	3.9	6.0	6.2	3.3	4.7	6.2	8.5	10.3	--	
INCOME TAX RATE	38.8%	43.3%	43.0%	40.6%	38.5%	40.8%	39.6%	39.1%	--	
NET PROFIT MARGIN	4.6%	5.1%	4.3%	2.2%	3.2%	3.8%	4.8%	5.2%	--	
WORKING CAP'L ($MILL)	d2.7	.1	4.1	9.2	6.4	3.9	d2.3	2.0	--	
LONG-TERM DEBT ($MILL)	10.0	40.3	55.3	54.8	49.7	42.3	28.0	32.0	--	
SHR. EQUITY ($MILL)	48.3	52.2	58.5	61.8	66.9	73.9	87.2	101.9	--	
RETURN ON TOTAL CAP'L	7.6%	7.5%	7.3%	4.6%	5.3%	6.4%	8.1%	8.4%	--	
RETURN ON SHR. EQUITY	8.1%	11.5%	10.5%	5.3%	7.0%	8.4%	9.8%	10.1%	--	
RETAINED TO COM EQ	8.1%	11.5%	10.5%	5.3%	7.0%	8.4%	9.8%	10.1%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

[A] No. of analysts changing earn. est. in last 9 days: 0 up, 0 down, consensus 5-year earnings growth 17.5% per year. [B] Based upon 2 analysts' estimates. [C] Based upon 2 analysts' estimates.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	8.0%	6.5%
"Cash Flow"	10.0%	14.0%
Earnings	7.5%	14.5%
Dividends	--	--
Book Value	9.0%	12.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	44.1	45.0	44.6	44.9	178.6
12/31/05	48.1	49.4	49.6	49.8	196.9
12/31/06	54.1	55.1	53.8		
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.11	.15	.13	.16	.55
12/31/04	.18	.19	.17	.17	.71
12/31/05	.20	.23	.17	.21	.81
12/31/06	.22	.25	.19	***.22***	
12/31/07	***.25***	***.28***			

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS

	1Q'06	2Q'06	3Q'06
to Buy	31	27	18
to Sell	35	35	31
Hld's(000)	9875	9124	8440

ASSETS ($mill.)	2004	2005	9/30/06
Cash Assets	1.4	.6	1.8
Receivables	13.5	14.8	14.8
Inventory	1.8	2.1	2.1
Other	4.9	4.8	5.2
Current Assets	21.6	22.3	23.9
Property, Plant & Equip, at cost	76.0	87.7	--
Accum Depreciation	36.7	42.5	--
Net Property	39.3	45.2	43.6
Other	93.3	103.2	104.2
Total Assets	154.2	170.7	171.7
LIABILITIES ($mill.)			
Accts Payable	7.5	6.9	8.4
Debt Due	.5	.1	.1
Other	15.9	13.3	14.3
Current Liab	23.9	20.3	22.8

LONG-TERM DEBT AND EQUITY as of 9/30/06

Total Debt $20.6 mill. **Due in 5 Yrs.** NA
LT Debt $20.6 mill.
Including Cap. Leases NA (16% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability None in '05 vs. None in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 12,312,075 shares (84% of Cap'l)

INDUSTRY: Medical Services

BUSINESS: American Dental Partners, Inc. provides business services to multidisciplinary dental groups in certain markets in the US. The company acquires certain assets of the dental practices with which it affiliates and enters into long-term service agreements with these affiliated dental groups. It provides services necessary for the administration of the nonclinical aspects of the dental operations. American Dental's services to the affiliated dental groups include providing assistance with organizational planning and development; recruiting, retention, and training programs; quality assurance initiatives; facilities development and management; employee benefits administration; procurement; information systems; marketing and payor relations; and financial planning, reporting, and analysis. As of October 30, American Dental Partners was affiliated with 21 dental groups, which had 201 dental facilities with approximately 1,876 operatories in 18 states. Has 2197 employees. Chairman, C.E.O. & President: Gregory A. Serrao. Inc.: DE. Address: 201 Edgewater Drive, Suite 285, Wakefield, MA 01880. Tel.: (781) 224-0880. Internet: http://www.amdpi.com. L.Y.

December 22, 2006

TOTAL SHAREHOLDER RETURN *Dividends plus appreciation as of 11/30/2006*

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
7.65%	27.85%	-5.09%	146.34%	266.62%

AMREP CORP. NYSE--AXR

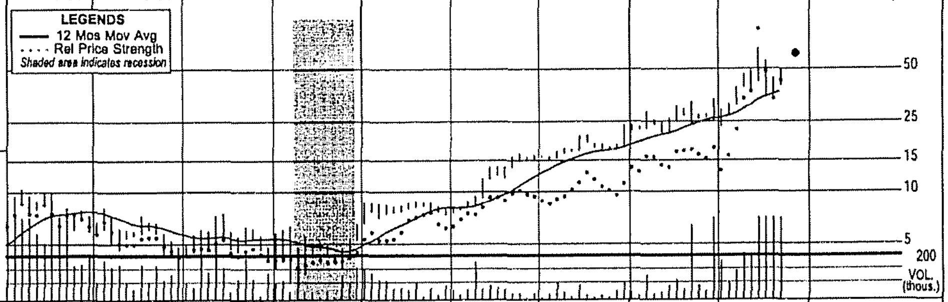
RECENT PRICE **61.17** | TRAILING P/E RATIO **11.1** | RELATIVE P/E RATIO **0.57** | DIV'D YLD **0.9%** | VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	10.50	8.00	7.44	6.50	8.85	16.45	24.00	33.88	65.00	High
Low	5.50	3.63	4.00	2.70	6.50	7.50	15.27	21.58	23.22	Low

RANKS

PERFORMANCE	2	Above Average
Technical	3	Average
SAFETY	3	Average
BETA .55		(1.00 = Market)

Financial Strength	B+
Price Stability	45
Price Growth Persistence	75
Earnings Predictability	35



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	25.82	16.55	11.14	12.69	11.20	19.83	20.30	19.99	--	
"CASH FLOW" PER SH	1.86	.73	.66	.97	1.42	2.52	3.16	3.78	--	
EARNINGS PER SH	1.21	.16	.38	.56	.95	1.77	2.35	3.39	NA	NA/NA
DIV'DS DECL'D PER SH	--	--	--	--	--	.25	.40	.55	--	
CAP'L SPENDING PER SH	.45	.37	.31	.44	.29	.55	.75	.53	--	
BOOK VALUE PER SH	12.43	12.70	13.66	14.22	14.24	15.96	17.72	16.04	--	
COMMON SHS OUTST'G (MILL)	7.37	7.24	6.57	6.57	6.59	6.61	6.63	7.42	--	
AVG ANN'L P/E RATIO	5.8	33.8	13.6	10.0	8.5	8.3	8.6	8.4	NA	NA/NA
RELATIVE P/E RATIO	.30	1.93	.88	.51	.46	.47	.45	.44	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	1.7%	2.0%	1.9%	--	
SALES ($MILL)	190.3	119.8	73.2	83.4	73.8	131.1	134.5	148.3	--	*Bold figures*
OPERATING MARGIN	10.4%	7.5%	8.1%	12.1%	18.3%	18.7%	21.5%	26.1%	--	*are consensus*
DEPRECIATION ($MILL)	4.8	4.1	1.8	2.7	3.1	5.0	5.3	5.6	--	*earnings*
NET PROFIT ($MILL)	8.9	1.2	2.6	3.7	6.3	11.7	15.6	22.5	--	*estimates*
INCOME TAX RATE	13.5%	40.0%	--	39.9%	36.4%	37.0%	31.8%	31.3%	--	*and, using the*
NET PROFIT MARGIN	4.7%	1.0%	3.5%	4.4%	8.5%	8.9%	11.6%	15.2%	--	*recent prices,*
WORKING CAP'L ($MILL)	112.4	97.2	93.3	81.1	79.2	88.5	93.3	100.6	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	47.9	31.3	34.8	13.2	14.3	10.8	10.0	4.3	--	
SHR. EQUITY ($MILL)	91.6	92.0	89.8	93.5	93.8	105.5	117.4	119.0	--	
RETURN ON TOTAL CAP'L	8.1%	2.1%	3.2%	4.1%	6.1%	10.4%	12.5%	18.4%	--	
RETURN ON SHR. EQUITY	9.7%	1.3%	2.8%	4.0%	6.7%	11.1%	13.3%	18.9%	--	
RETAINED TO COM EQ	9.7%	1.3%	2.8%	4.0%	6.7%	9.5%	11.1%	NMF	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	14%	17%	119%	--	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	2.5%	-1.5%
"Cash Flow"	24.0%	19.5%
Earnings	34.0%	44.5%
Dividends	--	37.5%
Book Value	5.0%	-9.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
04/30/05	33.6	33.2	31.5	36.2	134.5
04/30/06	30.1	34.8	35.6	47.8	148.3
04/30/07	58.3				
04/30/08					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
04/30/04	.54	.41	.51	.31	1.77
04/30/05	.59	.66	.38	.72	2.35
04/30/06	.28	.76	.79	1.56	3.39
04/30/07	2.38				
04/30/08					

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	.25	--	.25
2004	--	--	.40	--	.40
2005	--	--	.55	--	.55
2006	3.50	--	.85		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	7	10	24
to Sell	3	7	4
Hld's(000)	679	725	849

ASSETS ($mill.)	2004	2005	7/31/06
Cash Assets	37.7	46.9	95.2
Receivables	57.7	51.7	53.3
Inventory	52.9	47.5	42.1
Other	.0	.0	7.8
Current Assets	148.3	146.1	198.4
Property, Plant & Equip, at cost	31.6	34.6	--
Accum Depreciation	20.0	23.7	--
Net Property	11.6	10.9	20.0
Other	34.4	32.0	21.3
Total Assets	194.3	189.0	239.7
LIABILITIES ($mill.)			
Accts Payable	50.7	39.4	7.3
Debt Due	2.1	1.7	1.7
Other	2.2	4.5	17.4
Current Liab	55.0	45.6	26.4

LONG-TERM DEBT AND EQUITY as of 7/31/06

Total Debt $4.4 mill. Due in 5 Yrs. NA
LT Debt $2.7 mill.
Including Cap. Leases NA
(2% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability $3.2 mill in '05 vs $5.8 mill. in '04

Pfd Stock None Pfd Div'd Paid None

Common Stock 6,645,112 shares
(98% of Cap'l)

INDUSTRY: Diversified Co.

BUSINESS: AMREP Corporation engages in the real estate, fulfillment services, and newsstand distribution businesses. It conducts real estate business primarily in Rio Rancho, New Mexico.The company owns approximately 18,550 acres in Rio Rancho, as well as two tracts of land in Colorado, consisting of one residential property of approximately 160 acres planned for approximately 350 homes; and one property of approximately 10 acres zoned for commercial use. Its fulfillment services include magazine subscription, lettershop and graphics arts services, customer telephone support, list services, and product fulfillment services. The company distributes magazines for approximately 250 publishers in its newsstand distribution businesses. Among the titles are special interest magazines, including automotive, puzzle, men's sophisticates, comics, romance, and sports. Has 1295 employees. Chairman: Edward B. Cloues II. Inc.: OK. Address: 212 Carnegie Center, Suite 302, Princeton, NJ 08540. Tel.: (609) 716-8200. Internet: http://www.amrepcorp.com.

A.O.

October 20, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 9/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
-10.03%	23.72%	82.69%	237.92%	1139.61%

AXSYS TECH NDQ–AXYS

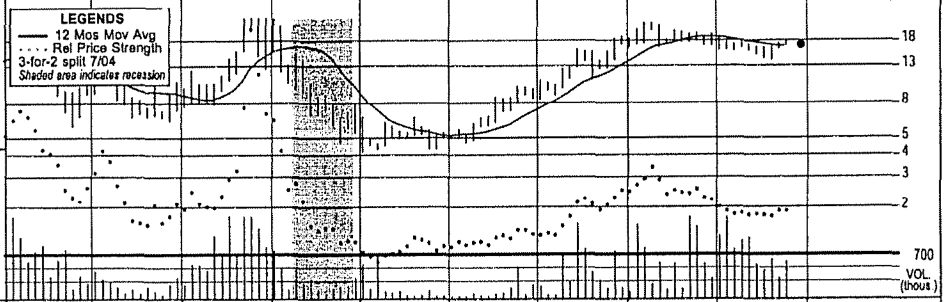
RECENT PRICE **16.98** | TRAILING P/E RATIO **17.9** | RELATIVE P/E RATIO **0.90** | DIV'D YLD **Nil** | VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	18.33	13.33	34.00	24.08	6.67	10.03	19.05	22.75	18.67	High
Low	5.83	6.25	7.50	4.71	4.14	4.67	8.33	16.45	13.89	Low

RANKS

PERFORMANCE	1	Highest
Technical	2	Above Average
SAFETY	3	Average
BETA .60	(1.00 = Market)	

Financial Strength	B+
Price Stability	40
Price Growth Persistence	35
Earnings Predictability	15



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	19.41	14.34	13.07	12.67	11.40	12.18	14.67	12.58	--	
"CASH FLOW" PER SH	2.12	.02	.03	d.58	d.05	1.13	1.69	1.08	--	
EARNINGS PER SH	1.35	d.47	d.41	d1.02	d.43	.71	1.26	.90	*.96*[A,B]	*1.09*[C]*/NA*
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	.60	.41	.56	.56	.20	.43	.60	.33	--	
BOOK VALUE PER SH	8.68	7.34	7.60	6.59	5.60	6.28	7.52	11.26	--	
COMMON SHS OUTST'G (MILL)	6.01	5.96	7.03	7.04	6.98	6.99	7.06	10.62	--	
AVG ANN'L P/E RATIO	9.1	--	--	--	--	9.8	10.4	20.9	*17.7*	*15.6/NA*
RELATIVE P/E RATIO	.47	--	--	--	--	.56	.55	1.11	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	116.6	85.4	91.8	89.2	79.6	85.1	103.5	133.5	--	***Bold figures***
OPERATING MARGIN	12.7%	3.6%	NMF	NMF	5.6%	9.3%	11.6%	13.4%	--	***are consensus***
DEPRECIATION ($MILL)	4.2	3.0	3.1	3.1	2.7	2.9	2.7	4.0	--	***earnings***
NET PROFIT ($MILL)	8.5	d2.9	d2.9	d7.2	d3.0	5.0	9.2	7.5	--	***estimates***
INCOME TAX RATE	11.1%	--	--	--	--	4.5%	--	37.5%	--	***and, using the***
NET PROFIT MARGIN	7.3%	NMF	NMF	NMF	NMF	5.9%	8.8%	5.6%	--	***recent prices,***
WORKING CAP'L ($MILL)	30.7	31.4	41.5	35.4	30.6	33.4	31.5	36.3	--	***P/E ratios.***
LONG-TERM DEBT ($MILL)	5.6	1.8	1.5	1.4	1.2	.6	3.5	--	--	
SHR. EQUITY ($MILL)	52.1	43.7	53.4	46.4	39.1	43.9	53.1	119.5	--	
RETURN ON TOTAL CAP'L	15.6%	NMF	NMF	NMF	NMF	11.4%	16.4%	7.0%	--	
RETURN ON SHR. EQUITY	16.4%	NMF	NMF	NMF	NMF	11.4%	17.3%	6.3%	--	
RETAINED TO COM EQ	16.4%	NMF	NMF	NMF	NMF	11.4%	17.3%	6.3%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

[A]No. of analysts changing earn. est. in last 18 days: 0 up, 0 down, consensus 5-year earnings growth 14.0% per year. [B]Based upon 4 analysts' estimates. [C]Based upon 4 analysts' estimates.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	-3.5%	-14.5%
"Cash Flow"	12.5%	-36.0%
Earnings	--	-28.5%
Dividends	--	--
Book Value	1.0%	49.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	23.4	25.7	26.4	28.0	103.5
12/31/05	28.6	33.4	35.6	35.9	133.5
12/31/06	37.5	38.5	39.8		
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.12	.21	.17	.21	.71
12/31/04	.23	.27	.27	.49	1.26
12/31/05	.22	.23	.22	.23	.90
12/31/06	.23	.24	.25	***.25***	
12/31/07	***.27***	***.25***			

Calendar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	22	20	17
to Sell	14	15	10
Hld's(000)	6222	5497	5589

ASSETS ($mill.)	2004	2005	9/30/06
Cash Assets	6.0	7.1	5.7
Receivables	15.7	18.8	18.9
Inventory (FIFO)	29.7	37.9	43.4
Other	4.6	4.4	4.4
Current Assets	56.0	68.2	72.4
Property, Plant & Equip, at cost	31.4	36.4	--
Accum Depreciation	18.1	21.0	--
Net Property	13.3	15.4	21.2
Other	16.5	72.6	71.8
Total Assets	85.8	156.2	165.4
LIABILITIES ($mill.)			
Accts Payable	6.5	8.0	8.3
Debt Due	1.4	.0	.0
Other	16.6	23.9	23.5
Current Liab	24.5	31.9	31.8

LONG-TERM DEBT AND EQUITY as of 9/30/06

Total Debt None **Due in 5 Yrs.** None
LT Debt None
Including Cap. Leases None
Leases, Uncapitalized Annual rentals NA

Pension Liability $ 6 mill. in '05 vs. $ .6 mill. in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 10,638,572 shares (100% of Cap'l)

INDUSTRY: Precision Instrument

BUSINESS: Axsys Technologies, Inc. makes micro-positioning and precision optical components, subsystems, and systems for high-performance markets. Axsys also distributes precision ball bearings for use in a variety of industrial and commercial applications. Through its Aerospace and Defense Group, the company offers its capabilities in magnetics, precision optics, precision machining, and subsystems integration to space and defense original equipment manufacturers (OEMs). Through its Commercial Products Group, Axsys makes and sells components, subsystems, and systems to high-performance OEMs and end users serving the electronics capital equipment, data storage, and digital imaging markets. It operates primarily in the United States and Europe. Has 749 employees. Chairman & C.E.O.: Stephen W. Bershad. Inc.: DE. Address: 175 Capital Boulevard, Suite 103, Rocky Hill, CT 06067. Tel.: (860) 257-0200. Internet: http://www.axsys.com.

A.O.

December 1, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 10/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
8.31%	3.03%	-8.59%	76.58%	175.24%

DYNAMICS RESEARCH NDQ--DRCO

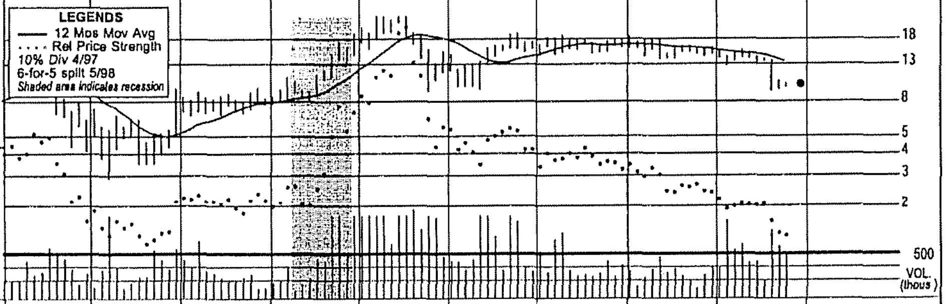
RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
9.96	17.5	0.89	Nil

VALUE LINE

RANKS											
High	12.75	9.50	9.59	19.50	25.30	19.50	18.90	18.67	15.65		High
Low	4.13	2.88	6.56	7.75	9.13	9.33	14.69	13.85	9.10		Low

PERFORMANCE 4 Below Average
Technical 3 Average
SAFETY 3 Average
BETA .50 (1.00 = Market)

Financial Strength B
Price Stability 30
Price Growth Persistence 60
Earnings Predictability 25



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	24.74	26.02	26.33	25.33	23.59	29.00	31.55	33.03	--	
"CASH FLOW" PER SH	.91	d.38	1.07	1.25	1.34	1.59	1.75	2.00	--	
EARNINGS PER SH	.06	d1.21	.56	.80	.83	.98	1.03	1.24	*.39*[A,B]	*.60*[C]*/NA*
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	.43	.37	.41	.47	.41	.97	.52	.50	--	
BOOK VALUE PER SH	4.24	3.23	3.85	4.68	4.88	5.76	7.02	8.16	--	
COMMON SHS OUTST'G (MILL)	7.37	7.36	7.60	7.94	8.16	8.44	8.74	9.10	--	
AVG ANN'L P/E RATIO	NMF	--	13.8	13.8	22.2	14.7	16.1	12.6	**25.5**	**16.6/NA**
RELATIVE P/E RATIO	NMF	--	.90	.71	1.21	.84	.85	.67	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	182.3	191.6	200.2	201.1	192.6	244.8	275.7	300.4	--	*Bold figures*
OPERATING MARGIN	4.8%	NMF	6.5%	7.6%	8.4%	8.2%	8.5%	9.3%	--	*are consensus*
DEPRECIATION ($MILL)	6.2	6.1	3.7	3.5	3.6	4.7	5.9	6.8	--	*earnings*
NET PROFIT ($MILL)	.5	d8.9	4.4	6.5	7.4	8.7	9.4	11.4	--	*estimates*
INCOME TAX RATE	41.2%	--	40.9%	40.7%	40.2%	42.3%	40.1%	40.5%	--	*and, using the*
NET PROFIT MARGIN	.3%	NMF	2.2%	3.2%	3.8%	3.5%	3.4%	3.8%	--	*recent prices,*
WORKING CAP'L ($MILL)	39.2	9.6	25.0	34.0	12.3	16.5	23.6	14.8	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	26.8	--	9.3	8.8	8.3	7.8	51.5	15.2	--	
SHR. EQUITY ($MILL)	31.3	23.8	29.3	37.1	39.8	48.7	61.3	74.2	--	
RETURN ON TOTAL CAP'L	2.2%	NMF	12.8%	14.9%	15.5%	15.7%	9.2%	15.3%	--	
RETURN ON SHR. EQUITY	1.6%	NMF	14.9%	17.5%	18.5%	17.8%	15.3%	15.4%	--	
RETAINED TO COM EQ	1.6%	NMF	14.9%	17.5%	18.5%	17.8%	15.3%	15.4%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

[A]No. of analysts changing earn. est. in last 4 days: 0 up, 1 down, consensus 5-year earnings growth 8.5% per year. [B]Based upon 6 analysts' estimates. [C]Based upon 6 analysts' estimates.

ANNUAL RATES of change (per share)	5 Yrs.	1 Yr.
Sales	4.0%	4.5%
"Cash Flow"	27.5%	14.0%
Earnings	--	20.5%
Dividends	--	--
Book Value	13.0%	16.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	62.1	65.0	70.5	78.1	275.7
12/31/05	73.5	76.2	79.1	71.6	300.4
12/31/06	68.2	67.3	61.6		
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.18	.23	.27	.30	.98
12/31/04	.23	.24	.25	.31	1.03
12/31/05	.23	.36	.34	.31	1.24
12/31/06	.16	.02	.08	*.14*	
12/31/07	*.13*	*.14*			

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS	4Q'05	1Q'06	2Q'06
to Buy	13	12	9
to Sell	4	11	11
Hld's(000)	3860	3745	3497

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	.9	1.0	.3
Receivables	94.1	93.1	82.2
Inventory (FIFO)	.0	.0	.0
Other	5.7	1.5	3.4
Current Assets	100.7	95.6	85.9
Property, Plant & Equip, at cost	58.2	32.3	--
Accum Depreciation	36.1	20.0	--
Net Property	22.1	12.3	12.2
Other	82.3	79.9	77.7
Total Assets	205.1	187.8	175.8
LIABILITIES ($mill.)			
Accts Payable	20.6	25.7	21.1
Debt Due	18.4	10.2	7.9
Other	38.1	44.9	36.8
Current Liab	77.1	80.8	65.8

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $23.4 mill. **Due in 5 Yrs. NA**
LT Debt $15.5 mill.
Including Cap. Leases NA (17% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability $5.3 mill in '05 vs $11.3 mill. in '04

Pfd Stock None **Pfd Div'd Paid None**

Common Stock 9,251,912 shares (83% of Cap'l)

INDUSTRY: Computer Software/Svcs

BUSINESS: Dynamics Research Corp. provides information technology (IT), engineering, logistics and other consulting services to federal defense, civil, and state agency customers. It operates in two segments: Systems and Services, and Metrigraphics. The Systems and Services segment provides technical and IT solutions that include operation and maintenance of business intelligence systems, defense program acquisition management services, training and performance support systems and services, and IT infrastructure services. The Metrigraphics segment develops and builds components for original equipment manufacturers. In September, Dynamics Research was awarded a new task order, worth at $1 million, to provide developmental research supporting the General Item Unique Identification program for the Air Force's Air Logistics Center at Hill Air Force Base, Utah. In October, Dynamics Research entered into a $50 million revolving credit facility. Has 1822 employees. Chmn., C.E.O., Pres. & C.O.O.: James P. Regan. Inc.: MA. Address: 60 Frontage Road, Andover, MA 01810. Tel.: (978) 475-9090. Internet: http://www.drc.com.
E.B.

November 17, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 10/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
-26.77%	-33.22%	-37.50%	-42.26%	-40.12%

EXPONENT INC. NDQ-EXPO

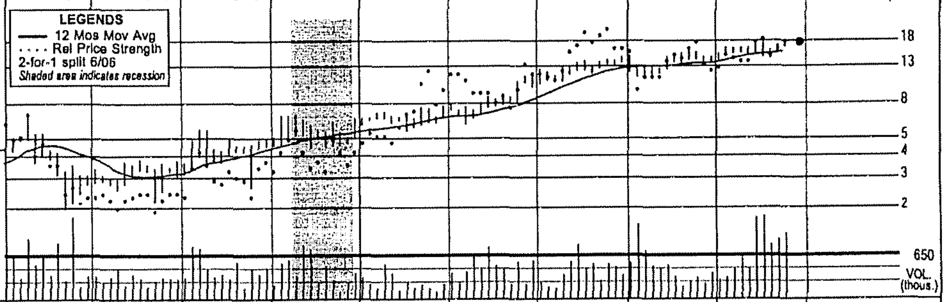
RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
17.68	21.8	1.12	Nil	VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	6.63	3.80	5.66	6.88	7.63	11.77	14.64	15.80	18.91	High
Low	1.97	2.19	2.63	4.40	5.50	6.02	10.27	11.23	14.01	Low

RANKS

PERFORMANCE	2	Above Average
Technical	2	Above Average
SAFETY	3	Average
BETA 55		(1.00 = Market)

Financial Strength	B++
Price Stability	65
Price Growth Persistence	90
Earnings Predictability	80



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	5.41	6.98	7.87	8.05	8.87	9.57	9.46	9.58	--	
"CASH FLOW" PER SH	.54	.74	.92	.83	.80	.93	1.01	1.09	--	
EARNINGS PER SH	.27	.39	.53	.43	.53	.64	.71	.81	NA	NA/NA
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	.34	.37	.67	.17	.15	.16	.16	.19	--	
BOOK VALUE PER SH	3.69	4.50	5.06	5.44	5.90	6.52	7.31	8.23	--	
COMMON SHS OUTST'G (MILL)	15.80	13.36	12.91	12.98	14.21	14.60	16.01	16.19	--	
AVG ANN'L P/E RATIO	15.0	8.1	8.0	12.5	12.4	13.0	18.0	16.7	NA	NA/NA
RELATIVE P/E RATIO	.78	.46	.52	.64	.68	.74	.95	.88	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	85.5	93.3	101.6	104.5	126.1	139.7	151.5	155.2	--	*Bold figures*
OPERATING MARGIN	10.2%	13.3%	14.9%	30.3%	27.7%	27.3%	27.9%	28.7%	--	*are consensus*
DEPRECIATION ($MILL)	4.5	4.4	4.4	4.7	3.4	3.4	4.1	3.4	--	*earnings*
NET PROFIT ($MILL)	4.1	5.4	7.4	6.1	7.9	10.2	12.0	14.2	--	*estimates*
INCOME TAX RATE	25.8%	41.5%	41.6%	42.4%	45.9%	42.6%	41.0%	37.3%	--	*and, using the*
NET PROFIT MARGIN	4.8%	5.8%	7.3%	5.9%	6.3%	7.3%	7.9%	9.1%	--	*recent prices,*
WORKING CAP'L ($MILL)	32.6	26.6	24.0	31.8	44.7	57.6	79.0	93.8	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	16.1	4.1	.2	.1	.2	.2	--	.1	--	
SHR. EQUITY ($MILL)	58.3	60.2	65.3	70.5	83.8	95.2	117.0	133.2	--	
RETURN ON TOTAL CAP'L	5.9%	8.9%	11.4%	8.7%	9.5%	10.7%	10.3%	10.6%	--	
RETURN ON SHR. EQUITY	7.0%	9.0%	11.4%	8.7%	9.5%	10.7%	10.3%	10.7%	--	
RETAINED TO COM EQ	7.0%	9.0%	11.4%	8.7%	9.5%	10.7%	10.3%	10.7%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

Note: No analyst estimates available.

ANNUAL RATES of change (per share)	5 Yrs.	1 Yr.
Sales	7.0%	1.5%
"Cash Flow"	6.5%	8.0%
Earnings	12.5%	15.0%
Dividends	--	--
Book Value	10.5%	12.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	38.8	39.6	38.0	35.1	151.5
12/31/05	39.2	39.9	37.2	38.9	155.2
12/31/06	42.0	41.7	43.3		
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.16	.17	.18	.13	.64
12/31/04	.22	.20	.18	.11	.71
12/31/05	.22	.23	.20	.16	.81
12/31/06	.22	.21	.22		
12/31/07					

Calendar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS	4Q'05	1Q'06	2Q'06
to Buy	34	29	32
to Sell	19	34	29
Hld's(000)	11752	11624	11459

ASSETS ($mill.)	2004	2005	9/29/06
Cash Assets	60.0	68.9	54.0
Receivables	38.6	46.2	51.4
Inventory	.0	.0	.7
Other	4.9	5.1	5.1
Current Assets	103.5	120.2	111.2
Property, Plant & Equip, at cost	66.2	68.1	--
Accum Depreciation	36.0	38.3	--
Net Property	30.2	29.8	29.8
Other	10.4	14.2	17.7
Total Assets	144.1	164.2	158.7
LIABILITIES ($mill.)			
Accts Payable	3.1	3.0	5.8
Debt Due	.0	.0	.0
Other	21.4	23.4	22.1
Current Liab	24.5	26.4	27.9

LONG-TERM DEBT AND EQUITY as of 9/29/06

Total Debt None **Due In 5 Yrs.** None
LT Debt None
Including Cap. Leases None
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '05 vs. None in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 14,920,571 shares (100% of Cap'l)

INDUSTRY: Industrial Services

BUSINESS: Exponent, Inc. operates as an engineering and scientific consulting company that provides solutions to problems facing industry and business. Its services include analysis of product development or product recall, regulatory compliance, discovery of potential problems related to products, people or property, and impending litigation, as well as the development of technical new products. The company also offers the services through a practice-focused format in the areas of Biomechanics, Civil Engineering, Data/Risk Analysis, EcoSciences, Electrical Engineering, Environmental Science, Food & Chemicals, Health and Epidemiology, Human Factors, Human Health Risk Assessment, Industrial Structures, Mechanical Engineering & Materials Science, Technology Development, Thermal Sciences, and Vehicle Analysis. Exponent serves clients in automotive, aviation, chemical, construction, energy, government, health, insurance, manufacturing, technology, and other sectors. Has 785 employees. Chairman: Leslie G. Denend. Inc.: DE. Address: 149 Commonwealth Drive, Menlo Park, CA 94025. Tel.: (650) 326-9400. Internet: http://www.exponent.com. *A.Z.*

December 8, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 10/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
14.85%	11.21%	25.61%	71.32%	262.36%

FRISCH'S RESTAURANTS AMEX--FRS

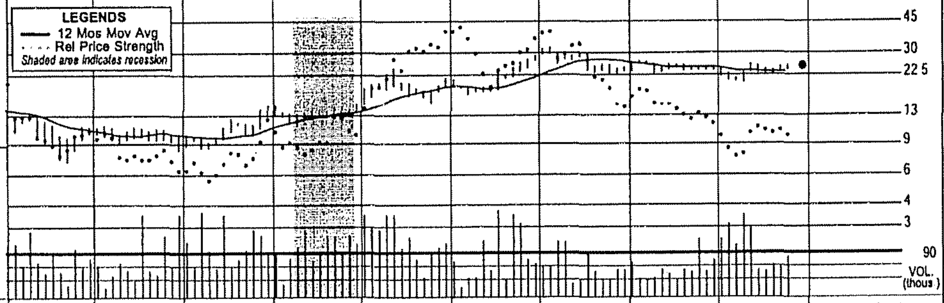
RECENT PRICE 25.25 | TRAILING P/E RATIO 14.7 | RELATIVE P/E RATIO 0.75 | DIV'D YLD 1.7% | VALUE LINE

RANKS

PERFORMANCE	3 Average
Technical	3 Average
SAFETY	3 Average
BETA .60	(1.00 = Market)
Financial Strength	B+
Price Stability	80
Price Growth Persistence	60
Earnings Predictability	65

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	13.88	11.50	15.13	15.45	24.80	28.98	32.24	26.90	26.00	High
Low	7.13	8.25	8.50	11.45	15.10	17.29	22.50	22.58	20.15	Low

LEGENDS
— 12 Mos Mov Avg
···· Rel Price Strength
Shaded area indicates recession



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	25.35	27.04	28.33	37.92	43.12	47.44	51.84	55.23	57.34	
"CASH FLOW" PER SH	2.30	2.56	2.66	3.22	3.57	4.19	4.27	5.28	4.39	
EARNINGS PER SH	.73	.86	1.08	1.47	1.59	1.95	2.05	2.82	1.78	*NA/NA*
DIV'DS DECL'D PER SH	.26	.28	.31	.32	.35	.36	.42	.44	.44	
CAP'L SPENDING PER SH	1.87	2.15	2.35	4.93	5.89	4.35	5.97	4.77	3.76	
BOOK VALUE PER SH	8.31	9.37	9.18	11.26	12.47	14.09	15.79	18.23	19.84	
COMMON SHS OUTST'G (MILL)	6.01	5.90	5.90	5.01	4.91	4.95	5.03	5.06	5.07	
AVG ANN'L P/E RATIO	18.7	11.9	9.0	8.3	10.2	9.6	12.6	9.0	13.3	*NA/NA*
RELATIVE P/E RATIO	.97	.68	.59	.43	.56	.55	.67	.48	.71	
AVG ANN'L DIV'D YIELD	1.9%	2.7%	3.2%	2.6%	2.2%	1.9%	1.6%	1.7%	1.9%	
SALES ($MILL)	152.2	159.6	167.2	190.0	211.8	234.9	260.9	279.2	291.0	***Bold figures***
OPERATING MARGIN	12.6%	12.8%	12.8%	12.0%	31.4%	32.5%	31.5%	30.9%	31.6%	***are consensus***
DEPRECIATION ($MILL)	9.3	9.9	9.6	8.6	9.6	11.0	11.0	12.1	13.1	***earnings***
NET PROFIT ($MILL)	4.5	5.2	6.1	7.6	8.0	9.8	10.5	14.6	9.2	***estimates***
INCOME TAX RATE	33.3%	36.3%	35.5%	34.5%	34.8%	33.5%	33.3%	24.9%	32.1%	***and, using the***
NET PROFIT MARGIN	3.0%	3.2%	3.6%	4.0%	3.8%	4.2%	4.0%	5.2%	3.1%	***recent prices,***
WORKING CAP'L ($MILL)	d8.5	d9.6	3.1	d10.9	d14.9	d14.0	d20.6	d21.2	d18.5	***P/E ratios.***
LONG-TERM DEBT ($MILL)	35.5	26.4	30.8	28.2	40.2	38.0	38.4	32.7	34.1	
SHR. EQUITY ($MILL)	49.9	55.3	54.2	56.5	61.2	69.8	79.5	92.2	100.7	
RETURN ON TOTAL CAP'L	7.1%	7.8%	8.6%	10.5%	9.1%	10.4%	10.0%	12.8%	7.9%	
RETURN ON SHR. EQUITY	9.1%	9.3%	11.2%	13.4%	13.0%	14.0%	13.2%	15.8%	9.1%	
RETAINED TO COM EQ	5.8%	6.3%	8.0%	10.5%	10.2%	11.5%	10.6%	13.4%	6.9%	
ALL DIV'DS TO NET PROF	36%	32%	29%	22%	22%	18%	20%	15%	24%	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	12.0%	4.0%
"Cash Flow"	10.5%	-17.0%
Earnings	14.5%	-37.0%
Dividends	7.5%	--
Book Value	12.5%	9.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
05/31/04	77.4	60.4	59.6	63.5	260.9
05/31/05	84.1	66.7	62.8	65.6	279.2
05/31/06	86.5	67.0	67.3	70.2	291.0
05/31/07	88.2				

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
05/31/03	.58	.44	.32	.61	1.95
05/31/04	.64	.47	.43	.51	2.05
05/31/05	.56	.53	1.19	.54	2.82
05/31/06	.50	.33	.43	.52	1.78
05/31/07	.44				

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.09	.09	.09	.11	.38
2004	.11	.11	.11	.11	.44
2005	.11	.11	.11	.11	.44
2006	.11	.11	.11	.11	.44

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	8	11	14
to Sell	6	10	7
Hld's(000)	1867	1911	2116

ASSETS ($mill.)	2005	2006	9/14/06
Cash Assets	.3	.8	.3
Receivables	1.2	1.5	1.4
Inventory (FIFO)	4.6	4.8	5.1
Other	3.7	5.0	5.0
Current Assets	9.8	12.1	11.8
Property, Plant & Equip, at cost	257.7	270.3	--
Accum Depreciation	109.5	115.9	--
Net Property	148.2	154.4	154.3
Other	7.6	8.8	8.3
Total Assets	165.6	175.3	174.4
LIABILITIES ($mill.)			
Accts Payable	12.8	10.3	11.6
Debt Due	8.1	9.3	9.2
Other	10.1	11.0	10.0
Current Liab	31.0	30.6	30.8

LONG-TERM DEBT AND EQUITY as of 9/14/06

Total Debt $41.3 mill. **Due in 5 Yrs.** NA
LT Debt $32.1 mill.
Including Cap. Leases NA (24% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability None in '06 vs. None in '05

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 5,078,501 shares (76% of Cap'l)

INDUSTRY: Restaurant

BUSINESS: Frisch's Restaurants, Inc. engages in the operation and licensing of full service family-style restaurants under the name "Frisch's Big Boy"; and operation of grill buffet style restaurants under the name "Golden Corral". As of September 19, it operated 90 Big Boy restaurants and 34 Golden Corral restaurants, as well as 28 Big Boy restaurants that were licensed to other operators. These restaurants are located in Ohio, Indiana, Kentucky, and Pennsylvania. Big Boy restaurants feature various items, such as the hamburger sandwich, onion rings, and hot fudge cake. Menu selections also include sandwiches, pasta, roast beef, chicken and seafood dinners, desserts, nonalcoholic beverages, and other items. The Golden Corral concept offers various buffet items, including fried and rotisserie chicken, meat loaf, pot roast, fish, and a carving station that rotates hot roast beef, ham, and turkey. Has about 9000 employees. C.E.O. & President: Daniel W. Geeding. Inc.: OH. Address: 2800 Gilbert Avenue, Cincinnati, OH 45206. Tel.: (513) 961-2660. Internet: http://www.frischs.com.

L.Y.

December 8, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 10/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
8.40%	8.08%	7.01%	8.40%	102.94%

LOJACK CORP NDQ-LOJN

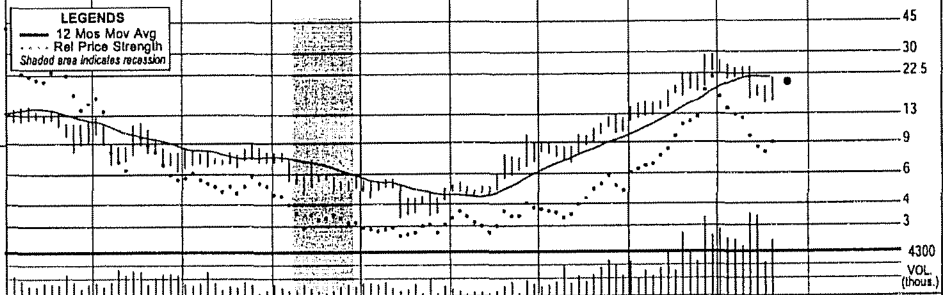
RECENT PRICE 20.10 | TRAILING P/E RATIO 20.3 | RELATIVE P/E RATIO 1.04 | DIV'D YLD Nil | VALUE LINE

High	15.63	12.75	8.88	7.97	5.65	9.90	12.85	29.00	26.79	High
Low	8.00	6.25	6.50	4.65	3.35	4.49	6.92	11.88	15.10	Low

RANKS

PERFORMANCE 4 Below Average
Technical 4 Below Average
SAFETY 3 Average
BETA .60 (1.00 = Market)

Financial Strength B+
Price Stability 35
Price Growth Persistence 20
Earnings Predictability 35



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	4.71	4.93	6.15	5.74	7.90	8.40	8.46	10.08	--	
"CASH FLOW" PER SH	.77	.60	.60	.42	.42	.66	.89	1.32	--	
EARNINGS PER SH	.53	.52	.45	.19	.12	.51	.64	.96	*1.05*[A,B]	*1.25*[C]*/NA*
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	.04	.15	.17	.26	.20	.29	.20	.41	--	
BOOK VALUE PER SH	1.42	1.18	1.40	1.34	1.38	1.95	3.71	5.49	--	
COMMON SHS OUTST'G (MILL)	17.66	18.28	15.58	14.70	14.74	14.98	17.22	18.93	--	
AVG ANN'L P/E RATIO	21.9	15.8	16.4	29.1	39.1	11.7	14.8	18.7	*19.1*	*16.1/NA*
RELATIVE P/E RATIO	1.14	.90	1.07	1.49	2.14	.67	.78	.99	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	83.2	90.2	95.9	84.4	116.4	125.8	145.7	190.7	--	***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.***
OPERATING MARGIN	23.8%	17.9%	13.8%	9.2%	6.1%	11.7%	14.5%	17.5%	--	
DEPRECIATION ($MILL)	3.3	1.9	1.9	3.2	4.3	2.3	4.9	6.6	--	
NET PROFIT ($MILL)	10.3	9.1	7.5	3.0	1.8	7.6	10.4	18.4	--	
INCOME TAX RATE	39.3%	38.9%	36.8%	37.0%	39.0%	39.0%	39.0%	33.0%	--	
NET PROFIT MARGIN	12.4%	10.1%	7.8%	3.5%	1.6%	6.1%	7.1%	9.7%	--	
WORKING CAP'L ($MILL)	18.8	17.4	18.8	14.3	12.8	21.5	30.5	67.3	--	
LONG-TERM DEBT ($MILL)	1.4	1.2	1.1	1.0	1.1	.2	20.9	14.5	--	
SHR. EQUITY ($MILL)	25.1	21.5	21.8	19.7	20.4	29.2	64.0	104.0	--	
RETURN ON TOTAL CAP'L	39.4%	40.7%	33.5%	14.7%	9.0%	26.1%	12.4%	16.0%	--	
RETURN ON SHR. EQUITY	41.0%	42.3%	34.4%	15.0%	9.0%	26.1%	16.3%	17.7%	--	
RETAINED TO COM EQ	41.0%	42.3%	34.4%	15.0%	9.0%	26.1%	16.3%	17.7%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

[A]No. of analysts changing earn. est. in last 23 days: 0 up, 0 down, consensus 5-year earnings growth not available. [B]Based upon 3 analysts' estimates. [C]Based upon 3 analysts' estimates.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	11.5%	19.0%
"Cash Flow"	8.0%	48.5%
Earnings	7.0%	50.0%
Dividends	--	--
Book Value	23.0%	48.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	32.2	35.9	38.0	39.6	145.7
12/31/05	42.9	49.1	52.3	46.4	190.7
12/31/06	50.7	56.7			
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.06	.12	.17	.16	.51
12/31/04	.10	.15	.21	.18	.64
12/31/05	.15	.26	.30	.25	.96
12/31/06	.15	.29	*.33*	*.29*	
12/31/07	*.23*				

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	77	72	56
to Sell	41	48	71
Hld's(000)	12891	14202	15560

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	21.4	47.6	35.1
Receivables	29.7	33.4	38.5
Inventory (FIFO)	12.6	18.0	17.9
Other	7.0	12.4	10.5
Current Assets	70.7	111.4	102.0
Property, Plant & Equip, at cost	28.7	35.7	--
Accum Depreciation	13.1	17.6	--
Net Property	15.6	18.1	20.9
Other	63.2	62.1	65.2
Total Assets	149.5	191.6	188.1
LIABILITIES ($mill.)			
Accts Payable	9.2	9.2	9.6
Debt Due	4.2	5.3	6.8
Other	26.8	29.6	32.0
Current Liab	40.2	44.1	48.4

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $19.2 mill. Due in 5 Yrs. NA
LT Debt $12.4 mill.
Including Cap. Leases NA
(11% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '05 vs. None in '04

Pfd Stock None Pfd Div'd Paid None

Common Stock 18,184,869 shares
(89% of Cap'l)

INDUSTRY: Electronics

BUSINESS: LoJack Corp. develops and markets the LoJack Stolen Vehicle Recovery System (LoJack System), a patented system, which comprises a registration system, a sector activation system, and vehicle tracking units. It also offers LoJack Early Warning recovery system, which provides early notification to vehicle owners in the event of unauthorized user operating the vehicle. In addition, the company offers Boomerang Tracking System, which consists of a cellular band radio frequency transponder with antenna, microprocessor, and power supply; Boomerang2 Unit, a product that builds upon the Boomerang Unit by integrating two-way communications and diagnostics to provide automatic theft notification; Water Resistant Boomerang Unit for installation on construction equipment and marine crafts; and Portable Boomerang Unit for installation in special applications. Has 890 employees. Chairman & C.E.O.: Joseph F. Abely. Inc.: MA. Address: 200 Lowder Brook Drive, Suite 1000, Westwood, MA 02090. Tel.: (781) 251-4700. Internet: http://www.lojack.com.

A.O.

October 6, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 8/31/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
18.30%	-8.22%	-1.00%	197.01%	265.67%

MAUI LD & PINEAPPLE AMEX–MLP

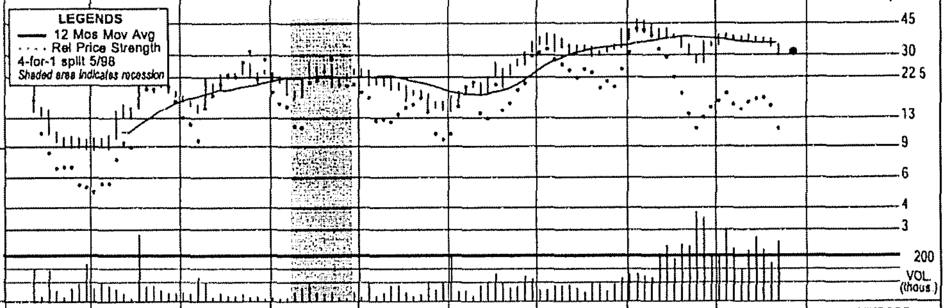
RECENT PRICE **31.05** | TRAILING P/E RATIO **12.6** | RELATIVE P/E RATIO **0.62** | DIV'D YLD **Nil** | VALUE LINE

	1998	1999	2000	2001	2002	2003	2004	2005	2006	
High	21.63	30.75	27.00	27.53	25.00	35.75	41.95	47.20	39.40	High
Low	8.63	8.50	14.00	17.00	13.75	14.15	29.20	26.75	29.27	Low

RANKS

PERFORMANCE 4 Below Average
Technical 3 Average
SAFETY — Short History
BETA .55 (1.00 = Market)

Financial Strength NMF
Price Stability 60
Price Growth Persistence 70
Earnings Predictability 5



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	19.99	20.43	19.66	22.46	21.61	23.44	20.88	25.21	--	
"CASH FLOW" PER SH	1.74	1.82	1.31	2.47	.75	2.23	1.33	3.97	--	
EARNINGS PER SH	.60	.65	.06	1.05	d.79	.54	d.06	2.02	NA	NA/NA
DIV'DS DECL'D PER SH	--	.13	.13	--	--	--	--	--	--	
CAP'L SPENDING PER SH	1.14	2.53	2.53	1.86	1.45	.94	1.57	2.33	--	
BOOK VALUE PER SH	8.69	9.23	9.16	10.20	8.72	9.94	9.91	12.57	--	
COMMON SHS OUTST'G (MILL)	7.19	7.20	7.20	7.20	7.20	7.20	7.23	7.25	--	
AVG ANN'L P/E RATIO	18.7	23.5	NMF	21.3	--	43.0	--	18.3	NA	NA/NA
RELATIVE P/E RATIO	.97	1.34	NMF	1.09	--	2.45	--	.97	--	
AVG ANN'L DIV'D YIELD	--	.8%	.6%	--	--	--	--	--	--	
SALES ($MILL)	143.7	147.0	141.5	161.6	155.5	168.7	150.9	182.9	--	*Bold figures*
OPERATING MARGIN	12.5%	12.7%	9.5%	9.0%	3.6%	12.6%	5.7%	18.8%	--	*are consensus*
DEPRECIATION ($MILL)	8.2	8.5	9.0	10.2	11.1	12.2	10.0	14.3	--	*earnings*
NET PROFIT ($MILL)	4.3	4.7	.5	7.6	d5.7	3.9	d.5	14.6	--	*estimates*
INCOME TAX RATE	17.8%	32.6%	--	31.3%	--	40.3%	--	37.5%	--	*and, using the*
NET PROFIT MARGIN	3.0%	3.2%	.3%	4.7%	NMF	2.3%	NMF	8.0%	--	*recent prices,*
WORKING CAP'L ($MILL)	18.9	13.0	19.3	25.5	25.5	23.6	11.2	8.9	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	23.6	25.6	41.0	39.6	43.3	23.0	14.0	10.3	--	
SHR. EQUITY ($MILL)	62.5	66.4	65.9	73.4	62.7	71.5	71.6	91.2	--	
RETURN ON TOTAL CAP'L	6.8%	6.1%	1.8%	8.2%	NMF	5.4%	.1%	14.6%	--	
RETURN ON SHR. EQUITY	6.9%	7.0%	.7%	10.3%	NMF	5.4%	NMF	16.0%	--	
RETAINED TO COM EQ	6.9%	5.7%	NMF	10.3%	NMF	5.4%	NMF	16.0%	--	
ALL DIV'DS TO NET PROF	--	19%	NMF	--	--	--	--	--	--	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	3.0%	20.5%
"Cash Flow"	9.0%	199.5%
Earnings	14.0%	--
Dividends	--	--
Book Value	3.5%	27.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	40.6	30.0	34.6	45.7	150.9
12/31/05	37.8	51.1	44.1	49.9	182.9
12/31/06	59.0	33.6			
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	d.09	d.56	1.12	07	.54
12/31/04	.21	d.33	d 30	.36	d.06
12/31/05	.17	.90	.28	.67	2.02
12/31/06	1.88	d.36			
12/31/07					

Calendar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	22	14	21
to Sell	7	19	14
Hld's(000)	1168	1308	1452

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	11.5	7.2	3.1
Receivables	12.7	19.6	14.6
Inventory (LIFO)	15.1	17.3	21.3
Other	8.1	5.3	5.6
Current Assets	47.4	49.4	44.6
Property, Plant & Equip, at cost	240.5	236.3	--
Accum Depreciation	146.6	139.4	--
Net Property	93.9	96.9	115.1
Other	19.6	39.7	50.0
Total Assets	160.9	186.0	209.7
LIABILITIES ($mill.)			
Accts Payable	12.7	18.4	14.8
Debt Due	3.3	.8	.4
Other	20.2	21.3	29.0
Current Liab	36.2	40.5	44.2

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $19.3 mill. Due in 5 Yrs. NA
LT Debt $18.9 mill.
Including Cap. Leases NA
(15% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability $29.8 mill. in '05 vs. $33.1 mill. in '04

Pfd Stock None Pfd Div'd Paid None

Common Stock 7,258,779 shares
(85% of Cap'l)

INDUSTRY: Food Wholesalers

BUSINESS: Maui Land & Pineapple Company, Inc. engages in the growing, packing, processing, and marketing of processed pineapple. The pineapples grown by the company primarily consist of Maui Gold and Hawaiian Gold, which are sold as whole fruits; Champaka, which is used for canning; and organic pineapple. It also sells pineapple juice, and pineapple juice blended with orange juice, and canned pineapple products. The company sells its products to grocery chains, food processors, wholesale grocers, and wholesalers in the United States and internationally. The company is also involved in the operation of Kapalua Resort, which includes three championship golf courses, a tennis facility, a vacation rental program, retail outlets, and regulated water and sewage transmission operations. In addition, Maui Land & Pineapple engages in the real estate entitlement, development, construction, and sales and leasing activities. Has 1275 employees. Chairman, C.E.O. & President: David C. Cole . Inc.: HI. Address: 120 Kane Street, P. O. Box 187, Kahului, Maui, HI 96733. Tel.: (808) 877-3351. Internet: http://www.mauiland.com.

L.Y.

October 27, 2006

TOTAL SHAREHOLDER RETURN
Dividends plus appreciation as of 9/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
-21.51%	-21.40%	-1.20%	14.73%	48.35%

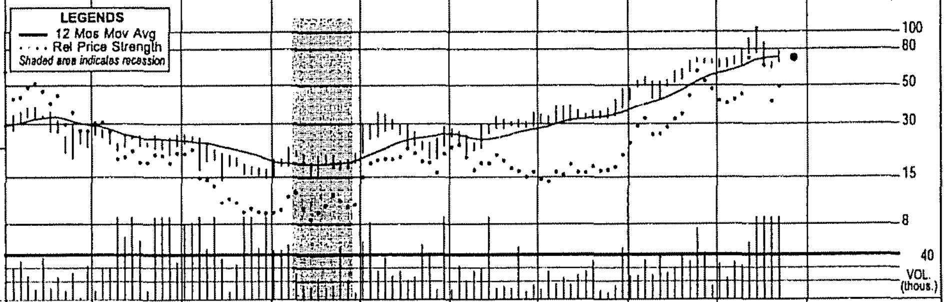
PATRIOT TRANSPORT. NDQ--PATR

RECENT PRICE	TRAILING P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
71.48	28.7	1.45	Nil	VALUE LINE

RANKS	1998	1999	2000	2001	2002	2003	2004	2005	2006	
	38.00	29.00	26.12	22.00	35.00	34.65	47.99	71.23	102.00	High
	19.00	20.00	14.25	15.00	18.84	20.00	29.92	41.06	62.41	Low

PERFORMANCE 3 Average
Technical 2 Above Average
SAFETY 3 Average
BETA .60 (1.00 = Market)

Financial Strength B+
Price Stability 45
Price Growth Persistence 55
Earnings Predictability 60



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
SALES PER SH	21.33	24.30	28.05	38.62	30.69	32.70	39.53	44.19	--	
"CASH FLOW" PER SH	3.93	4.81	3.94	4.84	5.30	5.03	6.26	6.77	--	
EARNINGS PER SH	1.28	1.78	.61	1.19	1.79	1.28	2.05	2.50	NA	NA/NA
DIV'DS DECL'D PER SH	--	--	--	--	--	--	--	--	--	
CAP'L SPENDING PER SH	4.42	6.38	6.52	5.87	5.71	7.27	7.50	9.64	--	
BOOK VALUE PER SH	19.83	21.53	22.06	23.28	25.06	24.70	33.49	36.39	--	
COMMON SHS OUTST'G (MILL)	3.47	3.38	3.35	3.14	3.16	3.16	2.93	2.97	--	
AVG ANN'L P/E RATIO	25.0	13.7	34.6	14.7	13.9	20.0	15.6	19.6	NA	NA/NA
RELATIVE P/E RATIO	1.30	.78	2.25	.75	.76	1.14	.82	1.04	--	
AVG ANN'L DIV'D YIELD	--	--	--	--	--	--	--	--	--	
SALES ($MILL)	74.0	82.0	93.9	121.3	96.9	103.3	115.8	131.0	--	*Bold figures*
OPERATING MARGIN	25.4%	27.4%	19.2%	17.3%	24.1%	21.2%	22.2%	21.1%	--	*are consensus*
DEPRECIATION ($MILL)	9.2	10.1	11.1	11.5	11.1	12.0	12.2	12.5	--	*earnings*
NET PROFIT ($MILL)	4.5	6.2	2.0	3.7	5.7	3.9	6.1	7.6	--	*estimates*
INCOME TAX RATE	39.0%	38.9%	40.5%	38.8%	39.0%	39.0%	38.9%	36.3%	--	*and, using the*
NET PROFIT MARGIN	6.1%	7.5%	2.2%	3.1%	5.8%	3.8%	5.3%	5.8%	--	*recent prices,*
WORKING CAP'L ($MILL)	.6	.6	d2.4	d.4	d.5	2.8	7.0	3.4	--	*P/E ratios.*
LONG-TERM DEBT ($MILL)	33.3	37.9	42.0	47.1	47.3	57.8	41.2	48.5	--	
SHR. EQUITY ($MILL)	68.8	72.7	73.8	73.1	79.2	78.0	98.1	107.9	--	
RETURN ON TOTAL CAP'L	5.5%	6.6%	3.2%	4.5%	5.8%	4.2%	5.6%	6.0%	--	
RETURN ON SHR. EQUITY	6.5%	8.5%	2.8%	5.1%	7.1%	5.0%	6.2%	7.1%	--	
RETAINED TO COM EQ	6.5%	8.5%	2.8%	5.1%	7.1%	5.0%	6.2%	7.1%	--	
ALL DIV'DS TO NET PROF	--	--	--	--	--	--	--	--	--	

Note: No analyst estimates available.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Sales	9.5%	12.0%
"Cash Flow"	7.5%	8.5%
Earnings	9.5%	22.0%
Dividends	--	--
Book Value	8.5%	8.5%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
09/30/04	27.9	28.6	29.7	29.6	115.8
09/30/05	31.4	32.1	33.1	34.4	131.0
09/30/06	35.4	35.6	37.6		
09/30/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
09/30/03	.30	.20	.44	.34	1.28
09/30/04	.44	.44	.64	.53	2.05
09/30/05	.56	.52	.70	.72	2.50
09/30/06	.62	.56	.59		
09/30/07					

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	--	--	--	--	--
2004	--	--	--	--	--
2005	--	--	--	--	--
2006	--	--	--		

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	6	6	19
to Sell	5	8	9
Hld's(000)	713	721	744

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	.2	3.0	.7
Receivables	9.1	11.7	10.9
Inventory (FIFO)	.6	.8	.8
Other	20.2	4.1	4.5
Current Assets	30.1	19.6	16.9
Property, Plant & Equip, at cost	224.2	246.7	--
Accum Depreciation	75.2	81.8	--
Net Property	149.0	164.9	186.0
Other	6.3	9.2	9.6
Total Assets	185.4	193.7	212.5
LIABILITIES ($mill.)			
Accts Payable	3.1	5.7	5.3
Debt Due	7.7	2.4	2.5
Other	12.3	8.1	11.2
Current Liab	23.1	16.2	19.0

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $59.7 mill. **Due in 5 Yrs.** NA
LT Debt $57.2 mill.
Including Cap. Leases NA (33% of Cap'l)
Leases, Uncapitalized Annual rentals NA

Pension Liability None in '05 vs. None in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 3,011,789 shares (67% of Cap'l)

INDUSTRY: Diversified Co.

BUSINESS: Patriot Transportation Holding, Inc. and its subsidiaries engage in the transportation and real estate businesses in the southeastern and mid-Atlantic states. The company's Transportation segment conducts its business through two wholly owned subsidiaries, Florida Rock & Tank Lines, Inc. and SunBelt Transport, Inc. Florida Rock & Tank Lines hauls petroleum-related liquids and other liquids, and dry bulk commodities by tank trucks. SunBelt Transport hauls building and construction materials on flatbed trailers. This segment primarily serves customers in the petroleum, and building and construction industries. The company's Real Estate segment acquires, constructs, leases, operates, and manages land and buildings. This segment also owns real estate, which is leased under mining royalty agreements or held for investment. Has 925 employees. Chairman: Edward L. Baker. Inc.: FL. Address: 1801 Art Museum Drive, Jacksonville, FL 32207. Tel.: (904) 396-5733. Internet: http://www.patriottrans.com.

A.Z.

October 20, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 9/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
-12.93%	9.89%	9.99%	151.03%	343.69%

YORK WATER CO NDQ–YORW

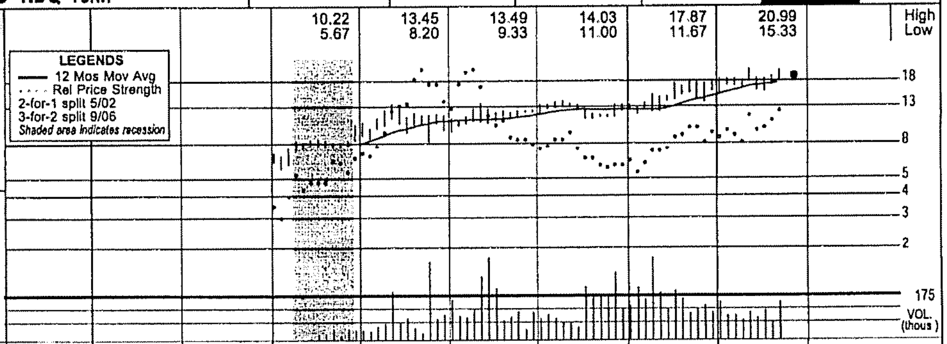
RECENT PRICE 19.13 | TRAILING P/E RATIO 34.2 | RELATIVE P/E RATIO 1.69 | DIV'D YLD 2.3% | VALUE LINE

	2001	2002	2003	2004	2005	2006	
High	10.22	13.45	13.49	14.03	17.87	20.99	High
Low	5.67	8.20	9.33	11.00	11.67	15.33	Low

RANKS

PERFORMANCE 2 Above Average
Technical 2 Above Average
SAFETY 3 Average
BETA .50 (1.00 = Market)

Financial Strength B+
Price Stability 60
Price Growth Persistence NMF
Earnings Predictability 85



© VALUE LINE PUBLISHING, INC.	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007/2008
REVENUES PER SH	--	--	--	2.05	2.05	2.17	2.18	2.58	--	
"CASH FLOW" PER SH	--	--	--	.59	.57	.65	.65	.79	--	
EARNINGS PER SH	--	--	--	.43	.40	.47	.49	.56	**.60**[A,B]	**.64**[C]/NA
DIV'D DECL'D PER SH	--	--	--	.34	.35	.37	.39	.42	--	
CAP'L SPENDING PER SH	--	--	--	.75	.66	1.07	2.50	1.69	--	
BOOK VALUE PER SH	--	--	--	3.79	3.90	4.06	4.65	4.85	--	
COMMON SHS OUTST'G (MILL)	--	--	--	9.46	9.55	9.63	10.33	10.40	--	
AVG ANN'L P/E RATIO	--	--	--	17.9	26.9	24.5	25.7	26.3	**31.9**	**29.9/NA**
RELATIVE P/E RATIO	--	--	--	.92	1.47	1.40	1.36	1.39	--	
AVG ANN'L DIV'D YIELD	--	--	--	4.3%	3.3%	3.2%	3.1%	2.9%	--	
REVENUES ($MILL)	--	--	18.5	19.4	19.6	20.9	22.5	26.8	--	
NET PROFIT ($MILL)	--	--	3.8	4.0	3.8	4.4	4.8	5.8	--	
INCOME TAX RATE	--	--	35.7%	35.8%	34.9%	34.8%	36.7%	36.7%	--	
AFUDC % TO NET PROFIT	--	--	--	2.2%	3.7%	--	--	--	--	
LONG-TERM DEBT RATIO	--	--	50.2%	47.7%	46.7%	43.4%	42.5%	44.1%	--	
COMMON EQUITY RATIO	--	--	49.8%	52.3%	53.3%	56.6%	57.5%	55.9%	--	
TOTAL CAPITAL ($MILL)	--	--	65.2	68.6	69.9	69.0	83.6	90.3	--	
NET PLANT ($MILL)	--	--	97.0	102.3	106.7	116.5	140.0	155.3	--	
RETURN ON TOTAL CAP'L	--	--	7.9%	7.9%	7.4%	8.5%	7.6%	8.4%	--	
RETURN ON SHR. EQUITY	--	--	11.6%	11.2%	10.2%	11.4%	10.0%	11.6%	--	
RETURN ON COM EQUITY	--	--	11.6%	11.2%	10.2%	11.4%	10.0%	11.6%	--	
RETAINED TO COM EQ	--	--	2.5%	2.5%	1.3%	2.6%	2.1%	3.0%	--	
ALL DIV'DS TO NET PROF	--	--	78%	78%	88%	77%	79%	74%	--	

Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.

[A]No. of analysts changing earn. est. in last 14 days: 0 up, 0 down, consensus 5-year earnings growth 7.0% per year. [B]Based upon 2 analysts' estimates. [C]Based upon 2 analysts' estimates.

ANNUAL RATES

of change (per share)	5 Yrs.	1 Yr.
Revenues	--	18.5%
"Cash Flow"	--	20.5%
Earnings	--	15.0%
Dividends	-9.5%	7.5%
Book Value	--	4.0%

Fiscal Year	QUARTERLY SALES ($mill.) 1Q	2Q	3Q	4Q	Full Year
12/31/04	5.3	5.5	5.6	6.1	22.5
12/31/05	6.2	6.7	7.2	6.7	26.8
12/31/06	6.6	7.0			
12/31/07					

Fiscal Year	EARNINGS PER SHARE 1Q	2Q	3Q	4Q	Full Year
12/31/03	.08	.11	.16	.12	.47
12/31/04	.12	.11	.12	.14	.49
12/31/05	.12	.14	.17	.13	.56
12/31/06	.12	.14	*.19*	*.16*	
12/31/07	*.13*				

Cal-endar	QUARTERLY DIVIDENDS PAID 1Q	2Q	3Q	4Q	Full Year
2003	.09	.09	.09	.09	.36
2004	.097	.097	.097	.097	.39
2005	.104	.104	.104	.104	.42
2006	.112	.112	.112	.112	.45

INSTITUTIONAL DECISIONS

	4Q'05	1Q'06	2Q'06
to Buy	10	8	9
to Sell	3	0	6
Hld's(000)	775	778	718

ASSETS ($mill.)	2004	2005	6/30/06
Cash Assets	.2	.0	.0
Receivables	3.7	3.8	4.4
Inventory	.7	.8	.8
Other	.4	.5	.7
Current Assets	5.0	5.1	5.9
Property, Plant & Equip, at cost	164.3	182.4	--
Accum Depreciation	24.3	27.1	--
Net Property	140.0	155.3	162.7
Other	11.1	11.9	12.8
Total Assets	156.1	172.3	181.4
LIABILITIES ($mill.)			
Accts Payable	1.8	2.6	4.1
Debt Due	16.3	19.3	22.5
Other	3.1	2.8	2.7
Current Liab	21.2	24.7	29.3

LONG-TERM DEBT AND EQUITY as of 6/30/06

Total Debt $62.3 mill. **Due in 5 Yrs.** NA
LT Debt $39.8 mill.
Including Cap. Leases NA
(43% of Cap'l)

Leases, Uncapitalized Annual rentals NA

Pension Liability $3.9 mill in '05 vs. $3.0 mill. in '04

Pfd Stock None **Pfd Div'd Paid** None

Common Stock 10,432,089 shares
(57% of Cap'l)

INDUSTRY: Water Utility

BUSINESS: York Water Company engages in the impounding, purification, and distribution of water in York County, Pennsylvania. The company has two reservoirs, Lake Williams and Lake Redman, which together held approximately 2.23 billion gallons of water. It supplies water for residential, commercial, industrial, and other customers. As of June 30, the company served approximately 56,281 customers in 34 municipalities in York County. Has 97 employees. C.E.O. & President: Jeffrey S. Osman. Inc.: PA. Address: 130 East Market Street, York, PA 17401. Tel.: (717) 845-3601. Internet: http://www.yorkwater.com.

A.O.

October 27, 2006

TOTAL SHAREHOLDER RETURN

Dividends plus appreciation as of 9/30/2006

3 Mos.	6 Mos.	1 Yr.	3 Yrs.	5 Yrs.
20.08%	9.67%	13.23%	82.58%	171.22%

Exhibit MJB-18
Unregulated Companies of Similar Size and Risk

Company Name	Beta	2005 Total Assets (Millions)	Five Year Total Shareholder Returns (dividends plus appreciation)	2005 Return on Shareholder Equity
American Dental	0.50	$ 170.7	266.62%	10.1%
AMREP Corp.	0.55	$ 189.0	1139.61%	18.9%
Axsys Tech	0.60	$ 156.2	175.24%	6.3%
Dynamics Research	0.50	$ 187.8	-40.12%	15.4%
Exponent Inc.	0.55	$ 164.2	262.36%	10.7%
Frisch's Restaurants	0.60	$ 165.6	102.94%	15.8%
Lojack Corp.	0.60	$ 191.6	265.67%	17.7%
Maui LD & Pineapple	0.55	$ 186.0	48.35%	16.0%
Patriot Transport	0.60	$ 193.7	343.69%	7.1%
York Water Co.	0.50	$ 172.3	171.22%	11.6%
		Average	273.56%	12.96%
		Median	218.80%	13.50%
Delta Natural Gas	0.55	$ 144.8	60.02%	9.8%

Source: The Value Line Investment Survey - Small and Mid-Cap Edition, various issues 2006

Exhibit MJB-19

Interst Coverage for the Edward Jones Panel of Natural Gas Distribution Companies

Company	**Interest Coverage**
New Jersey Resources, Inc.	5.71
EnergySouth, Inc.	5.08
AGL Resources, Inc.	4.29
South Jersey Industries, Inc.	4.18
WGL Holdings,Inc.	4.12
Piedmont Natural Gas Company	3.63
Northwest Natural Gas Company	3.35
RGC Resources, Inc.	3.18
Energy West	2.91
Laclede Group	2.85
Atmos Energy Corp.	2.77
Cascade Natural Gas Corp.	2.60
Delta Natural Gas Company	**2.56**
SEMCO Energy Inc.	1.42
Peoples Energy Corp.	0.25
Mean	3.26
Median	3.18

Source: Natural Gas Industry Summary Quarterly Financial & Common Stock Information, Edward Jones Co., December 31, 2006

RECEIVED
APR 2 0 2007
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL	)	
GAS COMPANY, INC. FOR AN	)	CASE NO. 2007-00089
ADJUSTMENT OF RATES	)	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, in the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony in such case.

William Steven Seelye

STATE OF INDIANA)
)
COUNTY OF MARION)

Subscribed and sworn to before me by William Steven Seelye, this the 18th day of April, 2007.

My Commission Expires: 2/14/2015

Notary Public, State at Large, Indiana

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

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

A. The purpose of my testimony is to sponsor Delta Natural Gas Company Inc.'s ("Delta's") proposed rates for natural gas service; to describe the proposed allocation of the revenue increase; to sponsor the fully allocated class cost of service study based on Delta's embedded costs for the 12 months ended December 31, 2006; to sponsor the temperature normalization adjustment; and to sponsor Delta's depreciation study supporting the proposed depreciation rates and the pro-forma adjustment to depreciation expenses.

Q. Please summarize your testimony.

A. Delta is proposing to increase base rate revenues by $5,562,341. The Company has a large residential customer base, and, as a result, Delta is proposing to allocate $3,847,230 of the increase to the residential class. The Company is proposing to collect these revenues by increasing the residential customer charge. By recovering all of the residential increase through the customer charge, we are proposing to move in the direction of a "straight fixed variable" rate design, which is a methodology that has been adopted in other regulatory jurisdictions. More specifically, Delta is proposing to recover through the monthly customer charge most of the customer-related costs identified in the cost of service study. The Prime Group prepared a fully allocated, embedded cost of service study for Delta's test-year operations using a cost of service methodology that has been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to determine the contribution that each customer class is making towards Delta's overall rate of return. Rates of return are computed for each rate class. Delta was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service. Delta is also proposing to make a temperature normalization adjustment to sales and transportation volumes not covered by the Company's Weather Normalization Adjustment ("WNA") clause. In addition, Delta is proposing to change a number of its depreciation rates based on the depreciation study included as an exhibit to my testimony.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Rate Design and the Allocation of the Increase, (III) Cost of Service Study, (IV) Temperature Normalization Adjustment, (V) Revenue Adjustment to Reflect Year-End Customers, and (VI) Depreciation Study and Depreciation Expense Adjustment.

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have performed cost of service and rate studies for over 100 investor-owned utilities, rural electric cooperatives, and municipal utilities. I have also developed or modified fuel and purchased power adjustment mechanisms for numerous electric and gas utilities, including integrated investor-owned utilities, integrated municipal utilities and distribution cooperatives. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes, on many occasions. Concerning my background related to the subject matters addressed in this proceeding, I have testified in other proceedings regarding rate design, revenue requirements, cost of service studies, pro-forma adjustments and depreciation expenses. A listing of my testimony is included in Seelye Exhibit 1.

II. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

Q. Is Delta proposing to change the relationship between the customer charge and volumetric charge for the residential rate class?

A. Yes. The Company is proposing a significant increase in its customer charge. Delta has a traditional residential base rate design consisting of a customer charge and a volumetric charge. This type of rate design is referred to as a "two-part" rate. Under this design, a portion of Delta's non-gas costs are collected through a monthly fixed customer charge, which does not vary with usage, and a volumetric charge applied to each Ccf used. Delta's residential customer charge is currently $9.80 per month and the non-gas volumetric charge is $0.41592 per Ccf (or $4.1592 per Mcf). Gas costs are recovered through the Gas Cost Recovery Rate (GCR), which is a volumetric charge.

Some regulatory jurisdictions have shifted from a traditional two-part rate design to a design in which all non-gas costs are recovered through a fixed monthly customer charge. This type of rate structure is referred to as a "straight fixed variable" rate design. This rate design evolved from pipeline rate designs that recovered all fixed costs through a fixed charge and all variable costs through a volumetric charge. Because non-gas costs are *fixed* for a gas distributor, and do not vary with the amount of gas purchased by its customers, all non-gas costs are recovered through a *fixed* monthly customer charge under a straight fixed variable rate structure.

The Missouri Public Service Commission ("Missouri Commission") recently adopted a straight fixed variable rate design for Atmos Energy Corporation (*Case No. GR-2006-0387*, Order dated February 22, 2007) and Missouri Gas Energy, a division of Southern Union Company (*Case No. GR-2006-0422*, Order dated March 22, 2007). The straight fixed variable rate design was proposed by the Missouri Commission Staff in the Atmos proceeding. A straight fixed variable rate design is also used by the Atlanta Gas Light Company in Georgia.

In the Atmos Proceeding, the Missouri Commission accepted the Staff's recommendation to eliminate the traditional two-part rate structure and to adopt instead a straight fixed variable design because collecting fixed costs through a volumetric charge:

- Creates unnecessary volatility in customer bills by collecting too much cost in the winter months;
- Sends incorrect price signals to residential customers;
- Forces residential customers whose usage is greater than the average to pay more than the cost of service, while allowing smaller customers to pay less than the cost of service;
- Provides no incentive for the utilities to promote conservation.

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, pp. 19-20.)

Q. Is Delta proposing a straight fixed variable rate design?

A. No. Although Delta is not recommending a straight fixed variable rate design, the Company is proposing to move significantly in that direction. Specifically, Delta is proposing to leave the volumetric charge at the current level and recover all of the residential revenue increase in the customer charge. Under a straight fixed variable design the non-gas volumetric charge would be eliminated and all of Delta's non-gas costs would be recovered through the monthly customer charge.

Although Delta's proposed residential rate will fall far short of recovering all fixed costs in the customer charge, it will come reasonably close to recovering the customer-related costs identified in the fully allocated class cost of service study submitted in this proceeding. In the cost of service study, Delta's non-gas fixed costs are classified as either customer-related or demand-related. With a straight fixed variable rate design adopted in Missouri and

Georgia all of these costs – both customer-related and demand-related fixed costs – would be recovered through the monthly customer charge. In this proceeding Delta is proposing to recover most – but not all – of its customer-related costs through the monthly customer charge. Delta's customer-related cost for residential customers is currently $24.16 per month. However, the Company is only charging $9.80 per month, or 41% of the customer-related costs that were identified in the cost of service study. In this proceeding, Delta is proposing to increase the monthly customer charge to $19.74, which represents 82% of the customer-related costs identified in the cost of service study. Although this increase in the customer charge is far less than it would be with straight fixed variable rate design, Delta's proposal is a significant shift in that direction.

Q. What would the customer charge be under a straight fixed variable design?

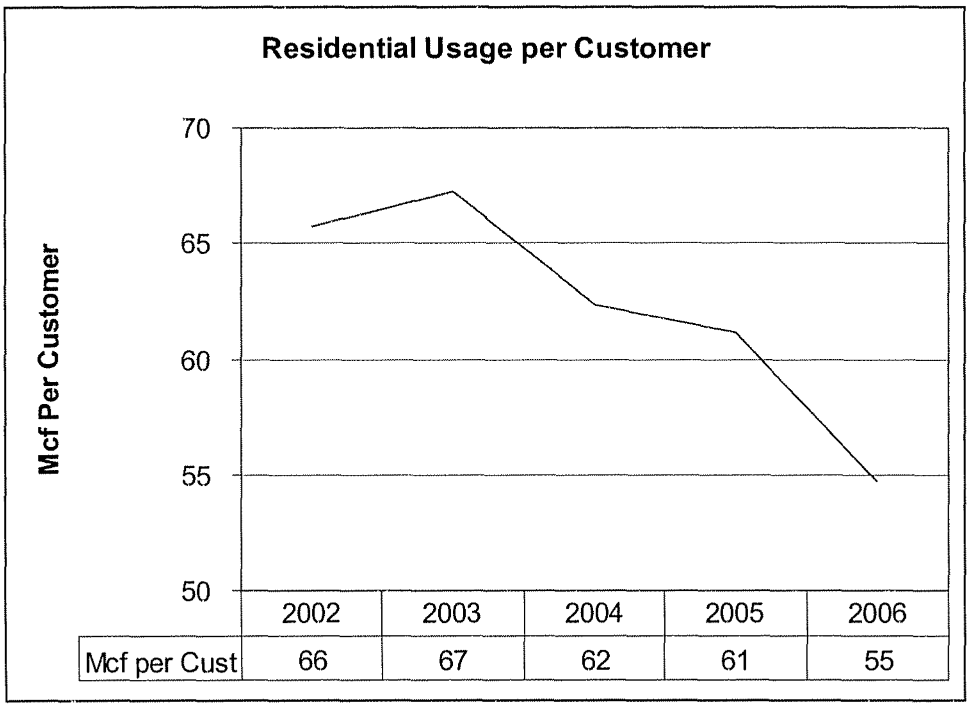
A. Under a straight fixed variable rate as was ordered by the Missouri Commission, the monthly customer charge would be $38.94, compared to the $19.74 charge proposed by Delta. Even with a $19.74 customer charge, approximately 50% of Delta's fixed costs will continue to be recovered through a volumetric charge.

Q. What are the benefits of recovering most of the customer-related costs through the customer charge?

A. Recovering more of Delta's customer-related costs through the fixed monthly customer charge will better reflect the actual cost of service through rates and will thus send a more accurate price signal to customers. In addition, Delta's proposed customer charge will reduce the volatility in customer bills by lowering the amount charged during the winter.

The Company's proposal will also eliminate rate subsidies within the residential customer class. Currently, customers with lower than average usage are being subsidized by customers with higher than average usage. Based on data that I have seen from other gas utilities, including a gas utility in the region, low income customers – contrary to a common misconception – tend to purchase more gas than the average customer. The likely reason for this is that low income customers often have poorly insulated homes, which causes their gas usage to be higher than the average even though their homes may have less square footage than the average. When customer-related costs are recovered through the volumetric charge, low income customers who use more than the average will subsidize customers who use less natural gas than the average.

Yet another advantage of Delta's proposal – and one which should be an important consideration for the Company – is that a higher customer charge should help mitigate the erosion in margins that Delta has been experiencing for a number of years. Delta's average Mcf per customer has been trending down for many years now. As shown in the following graph, in just four years the average residential usage has gone from 66 Mcf per customer in 2002 to 55 Mcf in 2006.



Because a large percentage of Delta's fixed costs have been recovered through a volumetric charge, the decline in customer usage has the effect of reducing the recovery of fixed costs and eroding the Company's earnings. Delta has not had an opportunity to earn the rate of return on equity authorized by the Commission in Delta's last three rate cases, and decreasing sales volumes have contributed heavily to this trend. Recovering more fixed costs through the customer charge should help mitigate this erosion in earnings. Furthermore, increasing the customer charge will work in tandem with the Experimental Customer Rate Stabilization ("CRS") Mechanism to provide Delta a reasonable opportunity to earn a fair, just and reasonable rate of return while preventing customers from being overcharged. Increasing the customer charge will in no way work at cross purposes with the CRS but, rather, will enhance the effectiveness of the proposed mechanism.

Q. Will the proposed rate design better position the Company to encourage conservation on the part of customers?

A. Yes it will, when considered in conjunction with the CRS and the proposed Conservation/ Efficiency Program (CEP) Cost Recovery Mechanism. Recovering a significant portion of fixed costs through a volumetric charge works to penalize the Company when customers conserve. Essentially all of Delta's non-gas costs are fixed and do not vary as customer volumes go up or down. With a significant portion of fixed costs recovered through volumetric charges, the Company's financial results are adversely affected from consumer conservation. Because Delta is not proposing to eliminate the volumetric charge for non-gas costs through the adoption a straight fixed variable rate design, the Company's non-gas revenues will continue to go down as a result of conservation, but not nearly as much as they would if Delta had proposed an increase in the volumetric charge. Furthermore, the adoption of the CRS and CEP Cost Recovery Mechanisms proposed by Delta will help position the Company so that it is not financially harmed by conservation on the part of customers. All three of these measures – increasing the customer charge, implementing the CRS Mechanism, and adopting the CEP Mechanism – work together as an integrated effort to help maintain Delta's financial integrity while encouraging customers to use less natural gas.

Q. Have you prepared an exhibit reconstructing Delta's test-year billing units?

A. Yes. In order to develop Delta's proposed rates it was necessary to reconstruct test-year billing units. The reconstruction of Delta's billing determinants is shown on Seelye Exhibit 2.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase apportioned to the individual customer classes?

A. Delta is proposing to increase its annual revenues by $5,641,650. As shown on Seelye Exhibit 3 , this amount would result in an increase of 9.2% in total operating revenue. In addition to requesting an increase in gas service rates, Delta is also proposing to increase the collection charge, reconnection charge, and bad check charge, all of which result in an increase in miscellaneous revenue of $79,309.

The proposed rates apportion the revenue increase among the customer classes as follows:

TABLE 1
Proposed Gas Increase

Customer Class	Proposed Increase	Percentage
Residential	$ 3,847,230	12.5%
Small Non-Residential	489,319	5.2%
Large Non-Residential	1,130,216	7.3%
Off-System Transportation	95,575	3.8%
Total Sales and Transportation	$ 5,562,341	9.2%

As shown on Seelye Exhibit 4, the effects on individual class revenues were determined by applying both the current and proposed charges to the adjusted billing determinants for each customer class.

Q. What was the basic underlying information that supported the proposed allocation among rate classes?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by the Company. The cost of service study indicated that the individual class rates of return ranged between 3.69%

and 19.11% as compared to an overall adjusted actual return on rate base of 5.71%, with residential being the lowest at 3.69%. This indicates a need to increase the revenues collected from the residential class more than the other classes. The rates of return for all of the rate classes except the special contracts were significantly higher than for residential. The cost of service study also showed that the earned return for the interruptible and off-system transportation rates were extremely high when compared to the other classes of service. Because the rate of return for the residential class is significantly below Delta's proposed overall rate of return of 8.82%, Delta is proposing to increase the residential rate by a larger percentage than the other classes in order to bring the residential rate of return more in line with the overall rate of return. The special contracts are served under fixed-price arrangements; therefore, none of the revenue increase will be allocated to these customers. Delta does not propose to increase the rates for the interruptible rate class because of the high rates of return for this rate class. With a rate of return of 19.11% for interruptible service, a rate increase for this rate class cannot be justified. Delta is proposing increases for the small and large non-residential rate classes that will result in a rate of return of around 10%, based on the results of the cost of service study, and the Company is proposing an increase in the off-system transportation rate that will produce a rate of return of approximately 9%.

Q. Is it important to consider competitive issues when designing rates?

A. Yes. It is extremely important to take into consideration the competitive pressures facing the utility when designing rates. Utility customers have many more options than they did in the past, and they are also becoming more sophisticated in how to utilize the various competitive products that are now available to them. However, the natural gas industry has always experienced keen competition from alternative fuels. When customers have alternatives (and the ability to substitute fuel oil for natural gas is only one example), gas distribution companies must be able to ensure that the revenues contributed by these customers are retained as long as they make some contribution to the utility's fixed costs. Industrial and commercial customers generally have more options than residential customers. Therefore, it is important not to charge rates to commercial and industrial customers that are uncompetitive and exceed the cost of providing service. Otherwise, large commercial and industrial customers will leave the system, forcing residential and small commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers. Unlike volumetric costs, such as the cost of the gas commodity that a distribution company buys for its customers, a utility's fixed costs generally do not disappear if it sells less gas, but instead are spread over a lower volume of gas, thus causing the utility's rates to increase. Therefore, if a utility loses several large high-load factor industrial customers, then the utility's fixed costs do not suddenly disappear but are shifted to the remaining customers in future rate proceedings. On the other hand, if the utility can attract high-load factor customers or, even better, customers with off-peak usage, then the utility's fixed costs can be spread over a larger volume of gas thus causing gas rates to go down, benefiting all customers. Again, that is why it is important for Delta to keep the rates applicable to price sensitive customers as competitive as possible while considering the cost of serving these customers.

Q. What were the ratemaking objectives in developing the proposed gas rates?

A. As explained earlier, we tried to develop rates that more closely reflect the cost of providing service. Therefore, one of our key objectives was to bring the unit charges more in line with the unit costs derived from the cost of service study. Thus, we developed rates that moved the charges toward the unit costs indicated by the cost of service study.

Q. Have you analyzed the customer-related costs for Delta's rate classes?

A. Yes. Page 20 of Seelye Exhibit 6 shows the unit customer-related costs for each rate class based on the results of the cost of service study. The customer-related cost for each rate class was derived by calculating the customer-related cost of service, or "revenue requirement" and dividing this amount by the number of customers. Delta's cost of service includes (1) return on investment, (2) income taxes, (3) operation and maintenance expenses, (4) depreciation expenses, and (5) other taxes. The proposed overall rate of return of 8.82% was used to calculate the unit cost.

Q. What are the proposed unit charges for the small non-residential rate class?

A. Delta is proposing a customer charge of $25.00 per customer per month and a flat commodity charge of $0.4159 for all Ccf. The current rate consists of a customer charge of $20.00 and commodity charge of $0.3795 per Ccf.

Q. What are the proposed unit charges for the large non-residential rate class?

A. Delta is proposing a customer charge of $100.00 per customer per month and a commodity charge of $0.4159 for the first 2,000 Ccf, $0.2510 for the next 8,000 Ccf, $0.1714 for the next 40,000 Ccf, $0.1314 for the next 50,000 Ccf, and $0.1114 for all usage over 100,000 Ccf. The first block was set at the same level as the first block in the small non-residential rate, and the current charge differentials between the blocks were maintained.

Q. Is Delta proposing to modify the interruptible or off-system transportation rate schedules?

A. No. As indicated earlier, rate increases for these services cannot be justified in light of the high class rates of return.

Q. Is Delta proposing to increase the off-system transportation rate?

A. Yes. We are proposing to increase the off-system transportation rate from $0.26 to $0.27 per dekatherm.

III. GAS COST OF SERVICE

Q. Did you prepare a cost of service study for Delta's natural gas operations based on financial and operating results for the 12 months ended December 31, 2006?

A. Yes. I supervised and participated in the preparation of a fully allocated, embedded cost of service study for natural gas service based on Delta's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended December 31, 2006. The Commission in other rate case proceedings has accepted the methodology used in Delta's cost of service study. The objective in performing the cost of service study is to determine the rate of return on rate base that Delta is earning from each customer class, which provides an indication as to whether Delta's service rates reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded cost of service study?

A. Yes, on many occasions. While employed at LG&E, I prepared numerous gas and electric cost of service studies, many of which were filed in rate cases before the Commission. Since leaving LG&E, I have prepared or supervised the preparation of well over 100 embedded cost of service studies for electric, gas and water utilities. In Kentucky, I supervised and participated in the preparation of gas cost of service studies for Delta (Case No. 99-176 and Case No. 2004-00067) and LG&E (Case No. 2003-00433 and Case No. 2000-080).

Q. Was the same methodology used in the cost of service study submitted in this proceeding that was used in the cost of service study filed by Delta in Case No. 2004-00067?

A. Yes.

Q. Did the Commission accept Delta's cost of service study filed in Case No. 2004-00067?

A. Yes it did, as set forth on page 57 of the Commission's November 10, 2004 Order in Case No. 2004-00067.

Q. Did you develop the model used to perform Delta's cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The cost of service study was prepared using the following basic procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to Delta's rate classes. This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated.

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Storage, (2) Transmission, (3) Distribution Commodity, (4) Distribution Structures and Equipment, (5) Distribution Mains, (6) Services, (7) Meters, (8) Customer Accounts, and (9) Customer Service Expense.

Q. How were costs classified as commodity related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics which give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were classified as demand-related and customer-related using the zero intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were all classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Seelye Exhibit 5 shows the results of the first two steps of the cost of service study: functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, Delta's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 5, Delta's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Seelye Exhibit 5. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Seelye Exhibit 5. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." The results of the class allocation step of the cost of service study are included in Seelye Exhibit 6. The costs shown in the column labeled "Total System" in Seelye Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 5. The column labeled "Ref" in Seelye Exhibit 6 provides a reference to the results included in Seelye Exhibit 5.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study:

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on expected winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the expected winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 7.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined at Delta's -3 degree F design-day mean temperature.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at Delta's -3 degree F design day mean temperature. These demands were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.

- **DEM05** is used to allocate the demand-related portion of the cost of distribution mains and represents maximum class demands determined at the design day mean temperature.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of December through March.)

- **COM03** is used to allocate Transmission commodity-related costs and represents annual throughput volumes (including both sales and transportation).

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation) of customers served on the distribution system.

- **CUST01** is used to allocate the customer-related portion of

Delta's distribution mains and represents the year-end number of customers.

- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST03** is used to allocate Meters and is based on the estimated cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and is determined on the basis of the average number of customers.

- **CUST05** is used to allocate customer service expenses using the same allocation factor used to allocate Accounts 901, 902, 903, and 905 in CUST04.

Q. How are mains typically classified between demand and customer costs?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero intercept methodology, a zero-diameter pipe is the absolute minimum system.

Q. What is the theory behind the zero intercept methodology?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and load carrying capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on Delta's system is not uniformly distributed over all sizes of pipe. For example, Delta has over 4.5 million feet of 2-inch plastic mains, but only 74 thousand feet of 3-inch plastic mains. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor (in this case the feet of pipe) for each size of pipe, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Seelye Exhibit 8 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $3.39 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.9194. The coefficient of determination is a relative measure of the goodness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

Q. Has the Commission accepted the use of the zero-intercept methodology in previous cases?

A. Yes, on many occasions. The Commission accepted the methodology in Delta's last rate case (Case No. 2004-00067). LG&E utilized the zero-intercept methodology in the cost of service studies submitted in its last two base rate cases (Case No. 2000-080 and Case No. 90-158) in which the Commission has issued orders and the Commission found them to be reasonable. The Commission also found the embedded cost of service study submitted by The Union Light Heat and Power in its gas base rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

Q. Please summarize the results of the gas cost of service study.

A. The following table (Table 2) summarizes the rates of return on net cost rate base for each customer class before and after reflecting the rate adjustments proposed by Delta. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	3.69%	7.88%
Small Non-Residential	7.03%	9.26%
Large Non-Residential	7.28%	10.10%
Interruptible	19.11%	19.11%
Special Contracts	3.23%	3.23%
Off-System Transportation	8.16%	8.81%
Total System	5.71%	8.82%

Q. Is the current rate of return for the residential class adequate?

A. No. As shown in Table 1, the rate of return for the residential class is below the rates of return for the other customer classes. Delta's overall adjusted rate of return is 5.17%, while the rate of return for the residential class is only 3.69%. In my opinion, Delta should be allowed to charge rates that bring the residential rate of return more in line with the overall rate of return.

Q. Would Delta's proposed rates move the company toward bringing the class rates of return closer together?

A. Yes. As can be seen in Table 1, the residential rates proposed by Delta result in a pro-forma rate of return of 7.88%, which brings the residential class within approximately 1 percentage point of the proposed overall rate of return of 8.82% (compared to 1.5 percentage points, currently).

IV. TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Please explain the calculations and methodology used to determine the temperature normalization adjustment to test period revenue.

A. Delta has a Weather Normalization Adjustment ("WNA") clause that automatically adjusts the commodity charge to reflect normal temperatures. The WNA clause is applicable to residential and small non-residential customers and is currently applied during the months of December through April. Because the WNA automatically normalizes customer billings for these two rate classes during the months of December through April it is not necessary to perform a temperature normalization adjustment for these two classes during these months. However, it is necessary to perform a temperature normalization adjustment for the residential and small non-residential customer classes to reflect the heating months not covered by the WNA. Additionally, it is necessary to perform a temperature normalization adjustment for rate classes not billed under the WNA, namely, large non-residential and interruptible rate classes.

Q. How was the gas temperature normalization adjustment performed for the rate classes not billed under the WNA?

A. A standard temperature normalization adjustment covering the entire heating season was performed for the large non-residential and interruptible rate classes. Heating degree days related to cycle billed customer deliveries were 196 below the 30-year average Weather Bureau heating-degree days of 4,662, where the 30-year average was determined using the period ended November 2006. Thus, Delta's actual revenues were understated due to warmer than normal temperatures experienced during the test period. The degree-day data used for purposes of calculating the temperature normalization adjustment was obtained from the Lexington, Kentucky weather station.

The first step in computing the temperature-related variance in deliveries was to determine the annual non-temperature sensitive and temperature sensitive volumes for each rate class. The determination of the non-temperature sensitive volumes was based on the gas deliveries that occurred in July and August since those months had the lowest volumes and also had no heating degree days. The volumes in those two months were then multiplied by six to calculate an annual non-temperature sensitive load that was deducted from total deliveries to arrive at the annual temperature sensitive volumes.

The next step was to determine the volumetric adjustment required to normalize deliveries to reflect normal temperatures. The annual temperature sensitive volumes were divided by the actual heating degree days (4,662 for billing cycle customers) in the test period and the resulting Mcf per degree day was then multiplied by the degree-day departure from normal (196 HDDs) to arrive at the volumetric adjustment for each rate class. In the final step, the volumetric adjustment for each rate class was applied to the applicable distribution component (rate per Mcf) for each rate schedule not billed under the WNA.

Q. How was the gas temperature normalization adjustment performed for the residential and small non-residential rate classes, which are billed under the WNA?

A. The same methodology was used for the residential and small non-residential rate classes except that the difference in degree days was determined only for the months outside of the period when the WNA is applied. In other words the temperature normalization was only applied to the 7 non-WNA months of May through November. Since the WNA adjusts customer volumes during the months of December through April, it was not necessary to make a temperature normalization adjustment during these months. During the months of May through November, actual heating degree days related to cycle billed customer deliveries were 54 above the 30-year average Weather Bureau heating-degree days of 712 for those months. This difference was then used in the calculation of the temperature normalization adjustment for the residential and small non-residential rate classes.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The temperature normalization adjustment results in a net increase of $106,452 to Delta's gas operating revenue. The calculation of this amount is summarized on Seelye Exhibit 9.

V. REVENUE ADJUSTMENT TO REFLECT YEAR-END CUSTOMERS

Q. Is Delta proposing to make a pro-forma adjustment to reflect the number of customers served at the end of the year?

A. No, and it respectfully asks that a year-end customer adjustment not be made in this proceeding. The purpose of such an adjustment is to normalize annual revenues to reflect a going forward level of customers. The rationale for a year-end adjustment is to compare the number of customers at the end of the test year to the average number of customers during the test year. If the year-end level is higher than the average then it is assumed that the Company is adding customers and that the year-end level of customers and associated revenues is more appropriate than the average test-year level on a going-forward basis for purposes of setting rates. Delta does not believe that the year-end level of customers reflects an appropriate going forward level of customers. In fact, it is likely that the revenues associated with the year-end level will overstate Delta's going forward revenue because the year-end level of customers will almost certainly be higher than the average number of customers during the first full year that the rates go into effect.

In this proceeding, the year-end level of customers is not higher than the average because of customer growth, but, rather, because of the selection of the 12 months ended December as the test year. A significant number of customers disconnect service during the summer months and return to the system during the winter months. Because the test year in this proceeding ends in December – which is a winter month – using the year-end level of customers overstates the customer level that should be used for purposes of normalization. As can be seen from the following table, Delta is not adding customers. In fact, Delta has been consistently losing customers over the past several years:

TABLE 3
Average Customers by Year

Year	Total Average Customers
2002	40,185
2003	39,765
2004	39,358
2005	38,981
2006	38,117

Based on this trend, one could expect that the number of customers served by Delta will continue to decrease, thus suggesting that a downward adjustment should be made to normalize revenues to reflect the number of customers served on a going forward basis. Delta is not proposing to make a downward revenue adjustment to reflect this trend, and asks that the Commission not make a year-end adjustment in this proceeding. The standard year-end adjustment is included in Seelye Exhibit 10 in the event that the Commission rejects the recommendation not to make a year-end adjustment.

VI. DEPRECIATION STUDY AND DEPRECIATION EXPENSE ADJUSTMENT

Q. Did you supervise the preparation of a depreciation study for Delta?

A. Yes.

Q. Was a standard methodology used to determine the depreciation accrual rates?

A. Yes. Where suitable information was available, the Simulated Plant Record (SPR) methodology was used to determine the survivor curve that best fit the plant retirement data for Delta's plant accounts. The SPR methodology is described in *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners and in other publications. Where sufficient data were not available, or the resulting statistics were not satisfactory, we relied heavily on comparisons to the survivor curves and depreciation rates utilized by neighboring gas utilities. The methodology used to develop the depreciation accrual rates is described in more detail in the report included in Seelye Exhibit 11.

Q. Was the same methodology used in this depreciation study as in study filed by Delta in its last rate case (Case No. 2004-00067)?

A. Yes. The Company submitted a depreciation study and made some corrections to the study in rebuttal testimony filed in that proceeding. The Commission accepted the corrected depreciation study filed by the Company. The depreciation study filed in this proceeding follows the methodology used in the corrected study that was approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

Seelye Exhibit 1

Summary of Qualifications

WILLIAM STEVEN SEELYE

Summary of Qualifications

Bachelor of Science degree in Mathematics; completed 54 hours of graduate level course work in Industrial Engineering and Physics. Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting and educational services in areas of utility marketing, regulatory analysis, revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Prepared and filed Order No. 888 and 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities. Prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Various Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education
Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Testified in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. Testified in Case No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Testified in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies and rate design. Testified in Cause No. 43111 on behalf of Vectren in support of a transmission cost recovery adjustment.

Kansas: Testified in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings. Testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates. Testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan and in Case No. 99-176 concerning cost of service, rate design and expense adjustments in connection with Delta's rate case. In Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program. Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings. Testified on behalf of Louisville Gas and Electric Company in Case No. 2003-00433 and on behalf of Kentucky Utilities Company in Case No. 2003-00434 regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design. Testified on behalf of Delta Natural Gas Company in Case No. 2004-00067 regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design. Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Nevada: Testified on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital and rate base adjustments. Testified on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10003 regarding cash working capital for an electric general rate case. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10005 regarding cash working capital for a gas general rate case. Testified on behalf of Nevada Power Company in Case Nos. 06-11022 and 06-11023 regarding cash working capital for a gas general rate case.

Seelye Exhibit 2

Reconstruction of Billing Determinants

Delta Natural Gas Company, Inc.

Calculations to Verify Test Period Billing Determinants
For the 12 months Ended December 31, 2003

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Actual Billed Revenue	Elimination of Gas Cost Adjustment	Billing Correction	Revenue Excluding Gas Cost Adjustment	Elimination of Weather Normalization Adjustment	Net Revenue	Calculated Net Revenue	Correction Factor
REVENUE		(See Gas Cost Exhibit)		(Column (1) + (2))	(See WNA Exhibit)	(Column (3) + (4))	(See Verification of Rates Exhibit)	(Column (6) / Column (5))
Residential	$ 34,527,341.00	$ (22,936,300.71)		$ 11,591,040.29	$ (371,842.00)	$ 11,219,198.29	$ 11,174,973.21	0.99606
Small Non-Residential GS	10,269,885.00	(7,026,753.45)		3,243,131.55	(109,891.00)	3,133,240.55	3,101,068.84	0.98973
Large Non-Residential GS								
Large Non-Residential GS - Commercial	13,254,779.00	(9,926,896.18)		3,327,882.82	-	3,327,882.82	3,328,998.71	1.00034
Large Non-Residential GS - Industrial	1,721,229.00	(1,380,929.29)		340,299.71	-	340,299.71	339,610.95	0.99798
Total Large Non-Residential GS	14,976,008.00	(11,307,825.47)		3,668,182.53	-	3,668,182.53	3,668,609.66	
Interruptible								
Interruptible -Commercial	39,289.00	(33,431.90)		5,857.10	-	5,857.10	5,602.40	0.95651
Interruptible - Industrial	484,019.46	(410,921.61)	(3,992.43)	69,105.42	-	69,105.42	69,674.40	1.00823
Total Interruptible	523,308.46	(444,353.51)	(3,992.43)	74,962.52	-	74,962.52	75,276.80	
Unmetered Gas Lights								
Residential	9,737.45	(7,262.07)		2,475.38	-	2,475.38	2,477.28	1.00077
Commercial	4,291.00	(3,266.82)		1,024.18	-	1,024.18	1,024.65	1.00046
Small Commercial	6,008.05	(4,573.55)		1,434.50	-	1,434.50	1,457.28	1.01588
Unmetered Gas Lights	20,036.50	(15,102.45)		4,934.05		4,934.05	4,959.21	
Total Retail	$ 60,316,578.96	$ (41,730,335.59)	$ (3,992.43)	$ 18,582,250.94	$ (481,733.00)	$ 18,100,517.94	$ 18,024,887.72	0.99582
Special Contracts	608,063.00			608,063.00		608,063.00	$ 608,062.27	1.00000
Small Non-Residential GS	147,218.00			147,218.00		147,218.00	147,698.65	1.00326
Large Non-Residential GS	2,016,375.00			2,016,375.00		2,016,375.00	2,023,250.48	1.00341
Residential	6,377.00			6,377.00		6,377.00	6,495.59	1.01860
Interuptible	1,550,100.00			1,550,100.00		1,550,100.00	1,550,747.52	1.00042
On System Transportation	4,328,133.00			4,328,133.00		4,328,133.00	4,336,254.51	
Off System Transportation	2,484,947.00			2,484,947.00		2,484,947.00	2,484,947.66	1.00000
Total Transportation	$ 6,813,080.00	$ -		$ 6,813,080.00	$ -	$ 6,813,080.00	$ 6,821,202.17	1.00119
Miscellaneous Revenue	$ 261,301.00	$ -		261,301.00		$ 261,301.00	$ 261,301.00	
Total Operating Revenue	$ 67,390,959.96	$ (41,730,335.59)	$ (3,992.43)	$ 25,656,631.94	$ (481,733.00)	$ 25,174,898.94	$ 25,107,390.89	0.99732
MCF								
Residential	1,778,782					1,778,782		
Small Non-Residential GS	544,113					544,113		
Large Non-Residential GS - Commercial	781,181					781,181		
Large Non-Residential GS - Industrial	107,456					107,456		
Interruptible - Commercial	2,564					2,564		
Interruptible - Industrial	32,652					32,652		
Unmetered Gas Lights - Total	1,250					1,250		
Total Retail	3,247,997					3,247,997		
On System Transportation Special	5,375,396					5,375,396		
Off System Transportation	8,525,855					8,525,855		
Total Transportation	13,901,252					13,901,252		
Total	17,149,249					17,149,249		

Seelye Exhibit 3

Summary of Proposed Increase

Delta Natural Gas Company, Inc.

Summary of Proposed Rate Increase by Rate Class
Based on Adjusted Sales and Transportation for the 12 months Ended December 31, 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Actual Billed Revenue	Elimination of Gas Cost Adjustment	Correction	Net Revenue Before Temperature Adjustment	Temperature Adjustment	GCR at Current Rates	Adjusted Billings at Current Rates	Proposed Increase in Revenue	Percentage Increase
REVENUE		(See Gas Cost Exhibit)		(Column (1) + (2))	(See Temperature Normalization Exhibit)	10.4200	(Column (3) + (4) + (5))		
Residential	$ 34,527,341	$ (22,936,301)		$ 11,591,040	$ (53,005)	$ 19,333,683	$ 30,871,718	$ 3,845,405	12.5%
Small Non-Residential GS	10,269,885	(7,026,753)		3,243,132	(11,271)	5,940,440	9,172,300	471,298	5.1%
Large Non-Residential GS									
Large Non-Residential GS - Commercial	13,254,779	(9,926,896)		3,327,883	89,258	8,384,984	11,802,126	563,300	4.8%
Large Non-Residential GS - Industrial	1,721,229	(1,380,929)		340,300	13,389	1,156,453	1,510,142	57,756	3.8%
Total Large Non-Residential GS	14,976,008	(11,307,825)		3,668,183	102,647	9,541,438	13,312,267	621,056	4.7%
Interruptible									
Interruptible - Commercial	39,289	(33,432)		5,857	314	28,759	34,930	-	
Interruptible - Industrial	484,019	(410,922)	(3,992)	69,105	1,568	350,445	421,119	-	
Total Interruptible	523,308	(444,354)	(3,992)	74,963	1,882	379,205	456,049	-	0.0%
Unmetered Gas Lights									
Residential	9,737	(7,262)		2,475		6,205	8,680	(1)	
Commercial	4,291	(3,267)		1,024		2,813	3,838	97	
Small Commercial	6,008	(4,574)		1,434		4,001	5,436	136	
Unmetered Gas Lights	20,037	(15,102)		4,934		13,020	17,954	232	1.3%
Total Retail	$ 60,316,579	$ (41,730,336)	$ (3,992)	$ 18,582,251	$ 40,253	$ 35,207,784	$ 53,830,288	$ 4,937,991	
Special Contracts	$ 608,063	$ -		$ 608,063	$ -	$ -	$ 608,063	$ -	
Small Non-Residential GS	147,218	-		147,218	5,207	-	152,425	17,885	
Large Non-Residential GS	2,016,375	-		2,016,375	60,993	-	2,077,368	509,063	
Residential	6,377	-		6,377	-	-	6,377	1,826	
Interruptible	1,550,100	-		1,550,100	-	-	1,550,100	-	
On System Transportation	4,328,133	-		4,328,133	66,200	-	4,394,333	528,775	12.0%
Off System Transportation	2,484,947	-		2,484,947	-	-	2,484,947	95,575	3.9%
Total Transportation	$ 6,813,080	$ -		$ 6,813,080	$ 66,200	$ -	$ 6,879,280	$ 624,350	9.1%
Miscellaneous Revenue	$ 261,301	$ -		$ 261,301			$ 261,301	$ 79,309	30.4%
Total Operating Revenue	$ 67,390,960	$ (41,730,336)	$ (3,992)	$ 25,656,632	$ 106,453	$ 35,207,784	$ 60,970,869	$ 5,641,650	9.3%

MCF	(1)	(5)	(6)
Residential	1,778,782	76,658	1,855,440
Small Non-Residential GS	544,113	25,987	570,100
Large Non-Residential GS - Commercial	781,181	23,520	804,701
Large Non-Residential GS - Industrial	107,456	3,528	110,984
Interruptible - Commercial	2,564	196	2,760
Interruptible - Industrial	32,652	980	33,632
Unmetered Gas Lights - Residential	596	-	596
Unmetered Gas Lights - Commercial	270	-	270
Unmetered Gas Lights Small Commercial	384	-	384
Total Retail	3,247,997	130,869	3,378,866
On System Transportation Special	5,375,396	17,444	5,392,840
Off System Transportation	8,525,855		8,525,855
Total Transportation	13,901,252	17,444	13,918,696
Total	17,149,249	148,313	17,297,562

Seelye Exhibit 4

Calculated Billings at Proposed Rates

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Residential

	Customers	*Present Rate*	*Calculated Net Revenue@ Present Rates*	*Proposed Rate*	*Proposed Rate Per Ccf*	*Calculated Net Revenue@ Proposed Rates*
Customer Charge	385,374	$ 9.80	$ 3,776,665.20	$ 19.74	$ 19.74	$ 7,607,282.76
Commodity Charge	*Mcf*					
All Mcf	1,778,782	$ 4.1592	7,398,308.01	$ 4.1592	$ 0.4159	7,397,952.26
Calculated Billings at Base Rates			$ 11,174,973.21			$ 15,005,235.02
Correction Factor -(Calculated / Actual)		*0.99606*		*0.99606*		
Total After Application of Correction Factor			$ 11,219,198.29			$ 15,064,618.40
Temperature Normalization						
All Mcf	76,658	$ 4.1592	318,837.16	$ 4.1592	$ 0.4159	318,821.83
	Mcf					
Adjusted Billings at Base Rates	1,855,440		$ 11,538,035.45			$ 15,383,440.23
GCR at Current Rates	1,855,440	10.4200	19,333,682.61	10.4200	$ 1.0420	19,333,682.61
Total Adjusted Billings at Base Rates			$ 30,871,718.06			$ 34,717,122.84
Proposed Increase in Revenue						$ 3,845,404.78
						12.46%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Small Non-Residential General Service

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	51,808	$ 20.00	$ 1,036,160.00	$ 25.00	$ 25.00	$ 1,295,200.00
Commodity Charge	*Mcf*					
All Mcf	544,113	$ 3.7950	2,064,908.84	$ 4.1592	$ 0.4159	2,262,965.97
Calculated Billings at Base Rates	544,113		$ 3,101,068.84			$ 3,558,165.97
Correction Factor -(Calculated / Actual)		*0.98973*		*0.9897*		
Total After Application of Correction Factor			$ 3,133,240.55			$ 3,595,079.79
Temperature Normalization						
First 200 Mcf	25,987	$ 3.7950	98,619.85	$ 4.1592	$ 0.4159	108,079.04
	Mcf					
Adjusted Billings at Base Rates	570,100		$ 3,231,860.40			$ 3,703,158.83
GCR at Current Rates	570,100	10.4200	5,940,439.75	10.4200	$ 1.0420	5,940,439.75
Total Adjusted Billings at Base Rates			$ 9,172,300.15			$ 9,643,598.58
Proposed Increase in Revenue						$ 471,298.43
						5.14%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Large Non-Residential General Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	9,664	$ 72.00	$ 695,808.00	$ 100.00	$ 100.00	$ 966,400.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	589,818	$ 3.7950	2,238,359.31	$ 4.1592	$ 0.4159	2,453,053.06
Next 800 Mcf	171,450	$ 2.1461	367,948.85	$ 2.5103	$ 0.2510	430,339.50
Next 4,000 Mcf	19,913	$ 1.3500	26,882.55	$ 1.7142	$ 0.1714	34,130.88
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	781,181		$ 3,328,998.71			$ 3,883,923.44
Correction Factor -(Calculated / Actual)		*1.0003*		*1.0003*		
Total After Application of Correction Factor			$ 3,327,882.82			$ 3,882,621.54
Temperature Normalization						
First 200 Mcf	23,520	$ 3.7950	89,258.40	$ 4.1592	$ 0.4159	97,819.68
	Mcf					
Adjusted Billings at Base Rates	804,701		$ 3,417,141.22			$ 3,980,441.22
GCR at Current Rates	804,701	10.4200	8,384,984.42	10.4200	1.0420	8,384,984.42
			$ 11,802,125.64			$ 12,365,425.64
Proposed Increase in Revenue						$ 563,300.00
						4.77%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Large Non-Residential General Service - Industrial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	616	$ 72.00	$ 44,352.00	$ 100.00	$ 100.00	$ 61,600.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	46,157	$ 3.7950	175,165.82	$ 4.1592	$ 0.4159	191,966.96
Next 800 Mcf	46,903	$ 2.1461	100,658.53	$ 2.5103	$ 0.2510	117,726.53
Next 4,000 Mcf	14,396	$ 1.3500	19,434.60	$ 1.7142	$ 0.1714	24,674.74
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	107,456		$ 339,610.95			$ 395,968.23
Correction Factor -(Calculated / Actual)		*0.99798*		*0.99798*		
Total After Application of Correction Factor			$ 340,299.71			$ 396,771.28
Temperature Normalization						
First 200 Mcf	3528	$ 3.7950	13,388.76	$ 4.1592	$ 0.4159	14,672.95
	Mcf					
Adjusted Billings at Base Rates	110,984		$ 353,688.47			$ 411,444.23
GCR at Current Rates	110,984	10.4200	1,156,453.28	10.4200	1.0420	1,156,453.28
			$ 1,510,141.75			$ 1,567,897.51
Proposed Increase in Revenue						$ 57,755.76
						3.82%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Interruptible Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	6	$ 250.00	$ 1,500.00	$ 250.00	$ 250.00	$ 1,500.00
	Mcf	*Present Rate*				
Commodity Charge						
First 1,000 Mcf	2,564	$ 1.6000	4,102.40	$ 1.6000	$ 0.1600	4,102.40
Next 4,000 Mcf	-	$ 1.2000	-	$ 1.2000	$ 0.1200	-
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	2,564		$ 5,602.40			$ 5,602.40
Correction Factor -(Calculated / Actual)		*0.95651*		*0.95651*		
Total After Application of Correction Factor			$ 5,857.10			$ 5,857.10
Temperature Normalization						
First 1,000 Mcf	196	$ 1.6000	313.60	$ 1.6000	$ 0.1600	313.60
	Mcf					
Adjusted Billings at Base Rates	2,760		$ 6,170.70			$ 6,170.70
GCR at Current Rates	2,760	10.4200	28,759.20	10.4200	1.0420	28,759.20
			$ 34,929.90			$ 34,929.90
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Interruptible Service - Industrial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	84	$ 250.00	$ 21,000.00	$ 250.00	$ 250.00	$ 21,000.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	23,730	$ 1.6000	37,968.00	$ 1.6000	$ 0.1600	37,968.00
Next 4,000 Mcf	8,922	$ 1.2000	10,706.40	$ 1.2000	$ 0.1200	10,706.40
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	32,652		$ 69,674.40			$ 69,674.40
Correction Factor -(Calculated / Actual)		*1.00823*		*1.00823*		
Total After Application of Correction Factor			$ 69,105.42			$ 69,105.42
Temperature Normalization					-	
First 1,000 Mcf	980	$ 1.6000	1,568.00	$ 1.6000	$ 0.1600	1,568.00
	Mcf					
Adjusted Billings at Base Rates	33,632		$ 70,673.42			$ 70,673.42
GCR at Current Rates	33,632	10.4200	350,445.44	10.4200	1.0420	350,445.44
			$ 421,118.86			$ 421,118.86
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Residential

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	397	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	596	$ 4.1600	2,477.28	$ 4.1592	$ 0.4159	2,476.68
Calculated Billings at Base Rates			$ 2,477.28			$ 2,476.68
Correction Factor -(Calculated / Actual)		*1.00077*		*1.00077*		
Total After Application of Correction Factor			$ 2,475.38			$ 2,474.78
Temperature Normalization						
	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	596		$ 2,475.38			$ 2,474.78
GCR at Current Rates	596	10.4200	6,205.11	10.4200	1.0420	6,205.11
			$ 8,680.49			$ 8,679.89
Proposed Increase in Revenue						$ (0.60)
						-0.01%

Seelye Exhibit 4
Page 7 of 16

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Commercial

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	180	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	270	$ 3.8000	1,026.00	$ 4.1592	$ 0.4159	1,122.93
Calculated Billings at Base Rates			$ 1,026.00			$ 1,122.93
Correction Factor -(Calculated / Actual)		*1.00046*		*1.00046*		
Total After Application of Correction Factor			$ 1,025.52			$ 1,122.41
Temperature Normalization						
	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	270		$ 1,025.52			$ 1,122.41
GCR at Current Rates	270	10.4200	2,813.40	10.4200	1.0420	2,813.40
			$ 3,838.92			$ 3,935.81
Proposed Increase in Revenue						$ 96.89
						2.52%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Small Commercial

	Lights	*Present Rate*	*Calculated Net Revenue@ Present Rates*	*Proposed Rate*	*Proposed Rate Per Ccf*	*Calculated Net Revenue@ Proposed Rates*
Customer Charge	252	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	384	$ 3.8000	1,459.20	$ 4.1592	$ 0.4159	1,597.06
Calculated Billings at Base Rates			$ 1,459.20			$ 1,597.06
Correction Factor -(Calculated / Actual)		*1.01588*		*1.01588*		
Total After Application of Correction Factor			$ 1,436.39			$ 1,572.09
Temperature Normalization						
	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	384		$ 1,436.39			$ 1,572.09
GCR at Current Rates	384	10.4200	4,001.28	10.4200	1.0420	4,001.28
			$ 5,437.67			$ 5,573.37
Proposed Increase in Revenue						$ 135.70
						2.50%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation

Special Contracts (4)

	Customers	*Mcf*		*Net Margin@ Present Rates*		*Net Margin@ Proposed Rates*
	48	2,801,367				
Calculated Billings at Base Rates				$ 608,062.27		$ 608,062.27
Correction Factor -(Calculated / Actual)			*1.00000*		*1.00000*	
Total After Application of Correction Factor				$ 608,063.00		$ 608,063.00

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation

Small Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	1,063	$ 20.00	$ 21,260.00	$ 25.00	$ 25.00	$ 26,575.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	33,317	$ 3.7950	126,438.65	$ 4.1592	$ 0.4159	138,566.10
Next 800 Mcf	-	$ 2.1461	-	$ 2.5103	$ 0.2510	-
Next 4,000 Mcf	-	$ 1.3500	-	$ 1.7142	$ 0.1714	-
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	33,317		$ 147,698.65			$ 165,141.10
Correction Factor -(Calculated / Actual)		*1.00326*		*1.00326*		
Total After Application of Correction Factor			$ 147,218.00			$ 164,603.69
Temperature Normalization						
First 200 Mcf	1,372.00	$ 3.7950	5,206.74	$ 4.1592	$ 0.4159	5,706.15
	Mcf					
Adjusted Billings at Base Rates	33,317		$ 152,424.74			$ 170,309.84
Proposed Increase in Revenue						$ 17,885.10 11.73%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation

Large Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	856	$ 72.00	$ 61,632.00	$ 100.00	$ 100.00	$ 85,600.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	92,819	$ 3.7950	352,249.39	$ 4.1592	$ 0.4159	386,035.63
Next 800 Mcf	212,762	$ 2.1461	456,609.43	$ 2.5103	$ 0.2510	534,033.68
Next 4,000 Mcf	573,158	$ 1.3500	773,763.38	$ 1.7142	$ 0.1714	982,392.91
Next 5,000 Mcf	235,080	$ 0.9500	223,325.92	$ 1.3142	$ 0.1314	308,895.01
Over 10,000 Mcf	207,560	$ 0.7500	155,670.36	$ 1.1142	$ 0.1114	231,222.37
Calculated Billings at Base Rates	1,321,380		$ 2,023,250.48			$ 2,528,179.60
Correction Factor -(Calculated / Actual)		*1.00341*		*1.00341*		
Total After Application of Correction Factor			$ 2,016,375.00			$ 2,519,588.25
Temperature Normalization						
First 200 Mcf	16,072	$ 3.7950	60,993.24	$ 4.1592	$ 0.4159	66,843.45
	Mcf					
Adjusted Billings at Base Rates	1,321,380		$ 2,077,368.24			$ 2,586,431.70
Proposed Increase in Revenue						$ 509,063.46
						24.51%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation
Residential

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	191	$ 10.00	$ 1,910.00	$ 19.74	$ 19.74	$ 3,770.34
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	1,103	$ 4.1592	4,585.59	$ 4.1592	$ 0.4159	4,585.37
Calculated Billings at Base Rates			$ 6,495.59			$ 8,355.71
Correction Factor -(Calculated / Actual)		*1.01860*		*1.01860*		
Total After Application of Correction Factor			$ 6,377.00			$ 8,203.16
Temperature Normalization						
All Mcf		$ 4.1592	-	$ 4.1592	$ 0.4159	-
	Mcf					
Adjusted Billings at Base Rates	1,103		$ 6,377.00			$ 8,203.16
Proposed Increase in Revenue						$ 1,826.16
						28.64%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation
Interruptible Service - Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	356	$ 250.00	$ 89,000.00	$ 250.00	$ 250.00	$ 89,000.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	299,009	$ 1.6000	478,413.93	$ 1.6000	$ 0.1600	478,413.93
Next 4,000 Mcf	648,134	$ 1.2000	777,760.75	$ 1.2000	$ 0.1200	777,760.75
Next 5,000 Mcf	214,604	$ 0.8000	171,683.24	$ 0.8000	$ 0.0800	171,683.24
Over 10,000 Mcf	56,483	$ 0.6000	33,889.60	$ 0.6000	$ 0.0600	33,889.60
Calculated Billings at Base Rates	1,218,229		$ 1,550,747.52			$ 1,550,747.52
Correction Factor -(Calculated / Actual)		*1.00042*		*1.00042*		
Total After Application of Correction Factor			$ 1,550,100.00			$ 1,550,100.00
Temperature Normalization						
First 1,000 Mcf		$ 1.6000	-	$ 1.6000	$ 0.1600	-
	Mcf					
Adjusted Billings at Base Rates	1,218,229		$ 1,550,100.00			$ 1,550,100.00
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Off System Transportation

	DDTH	Present Rate per DDTH	Calculated Net Revenue@ Present Rates	Proposed Rate Per DDTH	Calculated Net Revenue@ Proposed Rates
Commodity Charge					
Dekatherms	9,557,491	$ 0.2600	$ 2,484,947.66	$ 0.2700	2,580,522.57
Calculated Billings at Base Rates			$ 2,484,947.66		2,580,522.57
Correction Factor -(Calculated / Actual)		*1.00000*		*1.00000*	
Total After Application of Correction Factor			$ 2,484,947.00		$ 2,580,521.88
Temperature Normalization					
		$ -	-	$ -	-
Adjusted Billings at Base Rates			$ 2,484,947.00		$ 2,580,521.88
Proposed Increase in Revenue					$ 95,574.88
					3.85%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Miscellaneous Charges		Current		Proposed		
	Units	Charge	Revenue	Charge	Revenue	Difference
Collection Fees	9,154	$ 15.00	$ 137,310	$ 15.00	$ 183,080	$ 45,770
Reconnect Revenue	2,373	48.00	113,896.00	48.00	142,380	$ 28,484
Bad Check Revenue	1,010	10.00	10,095.00	10.00	15,150	$ 5,055
Total			$ 261,301		$ 340,610	$ 79,309

Seelye Exhibit 5

Class Cost of Service Study

Functional Assignment
And Classification

DELTA NATU' ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)									
Maintenance Expense -- Transmission and Distribution									
885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	37,668	49,004	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	16,313	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	2,812	3,659	1,344	1,752	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB	-	-	-	-	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	474,260	616,996	226,583	295,445	-	-
Total Maintenance Labor		LBDM		$ 514,740	$ 669,659	$ 227,927	$ 313,510	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 514,740	$ 669,659	$ 227,927	$ 313,510	$ -	$ -
Customer Accounts Expense									
901	Supervision	LB901	F012	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	-	-	-	-	404,578	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ 404,578	$ -
Customer Service Expenses									
907-910	Customer Service	LB907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Labor Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	LB920	LBSUB	$ 2,482,184	47,910	23,424	693,391	57,848	-	30,944
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT	-	-	-	-	-	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	1,036,705	20,010	9,783	289,600	24,161	-	12,924
927	Franxhise Requirement	LB927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$ 3,518,889	$ 67,920	$ 33,207	$ 982,991	$ 82,008	$ -	$ 43,867
Total Labor Expense		LBTOT		$ 6,765,762	$ 130,590	$ 63,847	$ 1,889,995	$ 157,677	$ -	$ 84,344

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Distribution Mains Demand		Distribution Mains Customer		Services Customer		Meters Customer		Customer Accounts Customer		Customer Service Expense Customer
Labor Expenses (Continued)															
Administrative & General															
920	Admin and General Salaries	LB920	LBSUB		393,510		511,944		174,247		239,674		309,294		-
921	Office Supplies and Expense	LB921	LBSUB		-		-		-		-		-		-
922	Admin. Expenses Transferred	LB922	LBSUB		-		-		-		-		-		-
923	Outside Services Employed	LB923	OMSUB		-		-		-		-		-		-
924	Property Insurance	LB924	PTT		-		-		-		-		-		-
925	Injuries and Damages	LB925	PTT		-		-		-		-		-		-
926	Employee Pensions and Benefits	LB926	LBSUB		164,353		213,818		72,776		100,102		129,179		-
927	Franxhise Requirement	LB927	PTT		-		-		-		-		-		-
928	Regulatory Commission Fee	LB928	PTT		-		-		-		-		-		-
929	Duplicate Charges -Dredit	LB929	PTT		-		-		-		-		-		-
930.1	General Advertising Expense	LB930.1	PTT		-		-		-		-		-		-
930.2	Misc. General Expense	LB930.2	OMSUB		-		-		-		-		-		-
931	Rents	LB931	PTT		-		-		-		-		-		-
935	Maintenance of General Plant	LB935	PT389		-		-		-		-		-		-
Total Administrative and General Labor		LBAG		$	557,863	$	725,761	$	247,022	$	339,775	$	438,473	$	-
Total Labor Expense		LBTOT		$	1,072,603	$	1,395,420	$	474,949	$	653,285	$	843,051	$	-

DELTA NATU 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses										
Production Expenses										
Operation & Maintenance										
753	Wells and Gathering	OM 753	F006	8,855	-	-	-	8,855	-	-
754	Compressor Station	OM754	F006	121,888	-	-	-	121,888	-	-
764	Maintenance of Wells and Gathering	OM764	F006	316	-	-	-	316	-	-
765	Maintenance of Compressor Station	OM765	F006	33,501	-	-	-	33,501	-	-
Total Production Operation & Maintenance Expenses				164,560	-	-	-	164,560	-	-
807-813	Procurement Expenses	OM807	DMCM	$ -	-	-	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-	-
816	Well Expenses	OM816	F003	61,646	61,646	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	46,077	-	46,077	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	103,330	-	103,330	-	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-	-
824	Other Expenses	OM824	F004	1,808	-	1,808	-	-	-	-
825	Storage Well Royalities	OM825	F003	56,371	56,371	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ 269,232	$ 118,017	$ 151,215	$ -	$ -	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	OM830	MSE	$ -	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	2,649	2,649	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	44,339	44,339	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	35,829	-	35,829	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	2,218	2,218	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	2,303	2,303	-	-	-	-	-
Total Maintenance Expense		OMME		$ 87,338	$ 51,509	$ 35,829	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		$ 356,570	169,526	187,044	-	-	-	-

DELTA NATU ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses									
Production Expenses									
Operation & Maintenance									
753	Wells and Gathering	OM 753	F006	-	-	-	-	-	-
754	Compressor Station	OM754	F006	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	OM764	F006	-	-	-	-	-	-
765	Maintenance of Compressor Station	OM765	F006	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	-	-	-	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-	-	-

DELTA NATI GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)											
Transmission											
850-867	Transmission Expenses	OM850	F005	$	66,285	-	-	66,285	-	-	-
Distribution Expenses											
Operation											
870	Operation Supr and Engr	OM870	DOES	$	-	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007		58,165	-	-	-	-	58,165	-
872	Compr. Station Labor and Exp.	OM872	F007		-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007		-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL		-	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009		-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010		-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL		-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010		-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009		-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009		-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007		-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009		-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009		-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008		-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011		-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008		-	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011		-	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011		-	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB		349,553	-	-	-	-	-	8,506
881	Rents	OM881	PTDSUB		17,394	-	-	-	-	-	423
Total Operations Distribution Expense		OMDO		$	425,112	-	-	-	-	58,165	8,930
Total Transmission and Distribution Oper Exp		OMTDO		$	622,140 $	- $	- $	66,285 $	130,743 $	58,165 $	8,930

DELTA NATI GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	100,258	130,432	47,900	62,457	-	-
881	Rents	OM881	PTDSUB	4,989	6,490	2,384	3,108	-	-
Total Operations Distribution Expense		OMDO		105,247	136,923	50,283	65,565	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 105,247	$ 136,923	$ 50,283	$ 65,565	$ -	$ -

DELTA NATU ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)																	
Maintenance Expense -- Transmission and Distribution																	
885	Maintenance Supr and Engr	OM885	DMES	$	-		-		-		-		-		-		-
886	Maintenance Structures	OM886	F008		-		-		-		-		-		-		-
887	Maintenance Mains	OM887	F009		150,379		-		-		-		-		-		-
888	Maintenance Comp. Station Equip.	OM888	F007		-		-		-		-		-		-		-
889	Maintenance Meas and Reg. General	OM889	F008		7,505		-		-		-		-		-		7,505
890	Maintenance Meas and Reg - Industrial	OM890	F011		-		-		-		-		-		-		-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-		-		-		-		-		-		-
892	Maintenance Services	OM892	F010		-		-		-		-		-		-		-
893	Maintenance Meters and House Reg.	OM893	F011		59,307		-		-		-		-		-		-
894	Maintenance Other Equipment	OM894	PTDSUB		112,086		-		-		-		-		-		2,728
898	Maintenance Transportaion Equip	OM898	PTDSUB		45,916		-		-		-		-		-		1,117
900	Trans & Distribution Expenses	OM900	TDSUB		3,344,534		-		-		1,184,720		-		-		52,558
Total Maintenance Expenses		OMME		$	3,719,727	$	-	$	-	$	1,184,720	$	-	$	-	$	63,908
Total Transmission & Distribution Expenses		OMDE		$	4,375,684	$	-	$	-	$	1,251,005	$	164,560	$	58,165	$	72,838
Customer Accounts Expense																	
901	Supervision	OM901	F012	$	-		-		-		-		-		-		-
902	Meter Reading	OM902	F012		-		-		-		-		-		-		-
903	Customer Records and Collections	OM903	F012	$	628,360		-		-		-		-		-		-
904	Uncollectible Accounts	OM904	F012		484,710		-		-		-		-		-		-
905	Misc. Cust Account Expenses	OM905	F012		-		-		-		-		-		-		-
Total Customer Accounts Expense		OMCA		$	1,113,070	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service Expenses																	
907-910	Customer Service	OM907	F013	$	-		-		-		-		-		-		-
Sales Expenses																	
911-916	Sales Expenses	OM911	F013	$	2,264		-		-		-		-		-		-

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Maintenance Expense -- Transmission and Distribution									
885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	65,355	85,024	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	59,307	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	32,148	41,824	15,359	20,027	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	13,170	17,133	6,292	8,204	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	619,473	805,914	295,961	385,908	-	-
Total Maintenance Expenses		OMME		$ 730,146	$ 949,895	$ 317,612	$ 473,446	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 835,393	$ 1,086,818	$ 367,895	$ 539,011	$ -	$ -
Customer Accounts Expense									
901	Supervision	OM901	F012	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	628,360	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	484,710	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ 1,113,070	$ -
Customer Service Expenses									
907-910	Customer Service	OM907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	2,264

DELTA NATU ɿAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	OM920	LBSUB	$ 2,576,284	49,727	24,312	719,677	60,041	-	32,117
921	Office Supplies and Expense	OM921	LBSUB	579,830	11,192	5,472	161,974	13,513	-	7,228
922	Admin. Expenses Transferred	OM922	LBSUB	(3,036,569)	(58,611)	(28,655)	(848,256)	(70,768)	-	(37,855)
923	Outside Services Employed	OM923	OMSUB	657,984	19,075	21,047	140,766	18,517	6,545	8,196
924	Property Insurance	OM924	PTT	786,124	77,118	-	255,578	-	-	11,021
925	Injuries and Damages	OM925	PTT	-	-	-	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	3,181,757	61,413	30,026	888,814	74,151	-	39,665
927	Franxhise Requirement	OM927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	163,359	16,025	-	53,110	-	-	2,290
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	562,597	16,310	17,996	120,359	15,832	5,596	7,008
931	Rents	OM931	PTT	-	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	183,395	14,231	-	59,922	-	-	2,658
Total Administrative and General Expense		OMAGT		$ 5,654,761	$ 206,481	$ 70,196	$ 1,551,944	$ 111,286	$ 12,141	$ 72,329
Total Operation & Maintenance Expense		OMT		$ 11,502,349	$ 376,007	$ 257,240	$ 2,802,949	$ 275,846	$ 70,306	$ 145,166

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	OM920	LBSUB	408,428	531,352	180,852	248,760	321,019	-
921	Office Supplies and Expense	OM921	LBSUB	91,923	119,588	40,703	55,987	72,250	-
922	Admin. Expenses Transferred	OM922	LBSUB	(481,399)	(626,284)	(213,164)	(293,204)	(378,373)	-
923	Outside Services Employed	OM923	OMSUB	94,000	122,291	41,396	60,651	125,245	255
924	Property Insurance	OM924	PTT	130,128	169,292	62,063	80,924	-	-
925	Injuries and Damages	OM925	PTT	-	-	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	504,416	656,229	223,356	307,223	396,464	-
927	Franxhise Requirement	OM927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	27,041	35,179	12,897	16,816	-	-
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	80,373	104,563	35,395	51,858	107,089	218
931	Rents	OM931	PTT	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	31,332	40,762	14,969	19,519	-	-
Total Administrative and General Expense		OMAGT		$ 886,243	$ 1,152,972	$ 398,469	$ 548,534	$ 643,694	$ 473
Total Operation & Maintenance Expense		OMT		$ 1,721,636	$ 2,239,790	$ 766,364	$ 1,087,545	$ 1,756,764	$ 2,737

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$	232,682	232,682	-	-	-	-	-
Transmission											
365-371	Transmission Plant	DP365	F005	$	1,122,524	-	-	1,122,524	-	-	-
Distribution											
374	Land & Land Rights	DP374	F008	$	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		3,300	-	-	-	-	-	3,300
376	Mains	DP376	F009		1,516,595	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		40,376	-	-	-	-	-	40,376
379	Meas & Reg Station Eq.-City Gate	DP379	F008		13,917	-	-	-	-	-	13,917
380	Services	DP380	F010		308,831	-	-	-	-	-	-
381	Meters	DP381	F011		196,929	-	-	-	-	-	-
382	Meter Installations	DP382	F011		129,421	-	-	-	-	-	-
383	House Regulators	DP383	F011		115,137	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		35,864	-	-	-	-	-	-
387	Other Equipment	DP387	F011		-	-	-	-	-	-	-
	Other		PTSUB		-	-	-	-	-	-	-
Total Distribution				$	2,360,370	$ -	$ -	$ -	$ -	$ -	$ 57,593
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		-	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB		531,163	41,218	-	173,551	-	-	7,699
Common Utility Plant		DPCP	PTSUB		-	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB		(12,000)	(931)	-	(3,921)	-	-	(174)
Accretion Expense		ACCRTN	PTSUB		-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$	4,234,739	$ 272,969	$ -	$ 1,292,154	$ -	$ -	$ 65,118

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Depreciation Expenses									
Underground Storage									
350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-
Transmission									
365-371	Transmission Plant	DP365	F005	-	-	-	-	-	-
Distribution									
374	Land & Land Rights	DP374	F008	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	-	-	-	-	-	-
376	Mains	DP376	F009	659,112	857,483	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-	-	-
380	Services	DP380	F010	-	-	308,831	-	-	-
381	Meters	DP381	F011	-	-	-	196,929	-	-
382	Meter Installations	DP382	F011	-	-	-	129,421	-	-
383	House Regulators	DP383	F011	-	-	-	115,137	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	35,864	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-
	Other		PTSUB	-	-	-	-	-	-
Total Distribution				$ 659,112	$ 857,483	$ 308,831	$ 477,351	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	90,747	118,059	43,356	56,532	-	-
Common Utility Plant		DPCP	PTSUB	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(2,050)	(2,667)	(979)	(1,277)	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 747,809	$ 972,875	$ 351,207	$ 532,606	$ -	$ -

DELTA NATU 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Taxes Other Than Income Taxes																
Liscense & Privilege Fee	OTRE	PTT	$	5,432		533		-		1,766		-		-		76
Property Taxes	OTPP	PTT		1,221,140		119,792		-		397,007		-		-		17,120
Payroll Taxes	OTUN	LBTOT		540,909		10,440		5,104		151,101		12,606		-		6,743
Total Taxes Other Than Income Taxes	OTT		$	1,767,481	$	130,765	$	5,104	$	549,874	$	12,606	$	-	$	23,940
Interest on Long Term Debt	INT	PTT	$	4,967,706		487,325		-		1,615,059		-		-		69,647

DELTA NATU ٦AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes								
Liscense & Privilege Fee	OTRE	PTT	899	1,170	429	559	-	-
Property Taxes	OTPP	PTT	202,136	262,972	96,406	125,705	-	-
Payroll Taxes	OTUN	LBTOT	85,752	111,561	37,971	52,229	67,400	-
Total Taxes Other Than Income Taxes	OTT		$ 288,788	$ 375,703	$ 134,806	$ 178,494	$ 67,400	$ -
Interest on Long Term Debt	INT	PTT	822,308	1,069,795	392,190	511,381	-	-

DELTA NATU ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Functional Assignment Vectors									
Gas Supply Demand	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 112,861,466	$ -	$ -	$ 51,227,484	$ -	$ -	$ -

DELTA NATU 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Functional Assignment Vectors								
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.434600	0.565400	0.000000	0.000000	0.000000	0.000000
Services	F010		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB	$	26,786,129	$ 34,847,853	$ -	$ -	$ -	$ -

DELTA NATI GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Internally Generated Functional Vectors									
Sub-Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024335
Storage-Transmission-Distribution Subtotal		PTSUB	1.000000	0.077600	-	0.326738	-	-	0.014495
Total Storage Plant		PTST	1.000000	1.000000	-	-	-	-	-
Transmission Plant		PT365	1.000000	-	-	1.000000	-	-	-
General Plant		PT389	1.000000	0.077600	-	0.326738	-	-	0.014495
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024335
Sub-Total CWIP		CWIP	1.000000	0.016915	-	0.800457	-	-	0.003160
Total Depreciation Reserve		DEPR	1.000000	0.083443	-	0.336804	-	-	0.014108
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	0.077600	-	0.326738	-	-	0.014495
Transmission and Distribution Payroll		LBTD	1.000000	-	-	0.329941	0.027526	-	0.014724
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	0.453897	-	-	-
Storage Operation Expenses Subtotal	OSE		82,393	61,280	21,113	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		10,917	1,390	9,527	-	-	-	-
Mains & Services	CADAL		74,431,389	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000						
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		112,790	-	-	-	-	-	239
Subtotal Labor Expenses	LBSUB		$ 3,246,873	$ 62,670	$ 30,640	$ 907,004	$ 75,669	$ -	$ 40,476
Subtotal O&M Expenses	OMSUB		$ 5,847,588	$ 169,526	$ 187,044	$ 1,251,005	$ 164,560	$ 58,165	$ 72,838

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Internally Generated Functional Vectors								
Sub-Total Distribution Plant		PTDSUB	0.286818	0.373140	0.137031	0.178676	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.170847	0.222266	0.081624	0.106431	-	-
Total Storage Plant		PTST	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-
General Plant		PT389	0.170847	0.222266	0.081624	0.106431	-	-
Total Distribution Plant		PTDSUB	0.286818	0.373140	0.137031	0.178676	-	-
Sub-Total CWIP		CWIP	0.060182	0.078295	0.017792	0.023199	-	-
Total Depreciation Reserve		DEPR	0.166283	0.216329	0.079444	0.103588	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.170847	0.222266	0.081624	0.106431	-	-
Transmission and Distribution Payroll		LBTD	0.187247	0.243602	0.082913	0.114046	-	-
Transmission and Distribution Mains		TDMSUB	0.237336	0.308767	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-	-	-
Mains & Services	CADAL		26,786,129	34,847,853	12,797,407	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM							
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		40,480	52,663	1,344	18,065	-	-
Subtotal Labor Expenses	LBSUB	$	514,740 $	669,659 $	227,927 $	313,510 $	404,578 $	-
Subtotal O&M Expenses	OMSUB	$	835,393 $	1,086,818 $	367,895 $	539,011 $	1,113,070 $	2,264

Seelye Exhibit 6

Class Cost of Service Study

Allocation of Costs by Rate Class

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Plant in Service										
Gas Supply Costs										
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	PTIS	PTISSD	DEM02	$ 17,875,861	$ 8,293,256	$ 2,639,573	$ 6,943,033	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage				$ 17,875,861	$ 8,293,256	$ 2,639,573	$ 6,943,033	$ -	$ -	$ -
Transmission										
Demand	PTIS	PTISTD	TDEM	$ 57,549,027	$ 16,048,581	$ 5,092,582	$ 12,544,907	$ 2,581,547	$ 5,290,335	$ 15,991,076
Commodity	PTIS	PTISTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission				$ 57,549,027	$ 16,048,581	$ 5,092,582	$ 12,544,907	$ 2,581,547	$ 5,290,335	$ 15,991,076
Distribution Expenses										
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	PTIS	PTISDSD	DEM04	$ 2,553,073	$ 1,117,345	$ 354,559	$ 873,410	$ 179,734	$ 28,025	$ -

DELTA NATUI.   ƷAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Plant in Service (Continued)											
Distribution Mains											
Demand	PTIS	PTISDMD	DEM05	$	30,091,574 $	13,169,488 $	4,178,980 $	10,294,368 $	2,118,421 $	330,319 $	-
Customer	PTIS	PTISDMC	CUST01		39,148,127 $	33,505,627 $	4,694,354 $	907,953 $	39,163 $	1,031 $	-
Total Distribution Mains					69,239,701 $	46,675,115 $	8,873,333 $	11,202,321 $	2,157,583 $	331,349 $	-
Services											
Customer	PTIS	PTISSC	CUST02	$	14,376,625 $	10,402,095 $	2,949,667 $	979,288 $	42,239 $	3,335 $	-
Meters											
Customer	PTIS	PTISMC	CUST03	$	18,745,871 $	11,403,369 $	1,852,410 $	4,322,532 $	1,035,848 $	131,713 $	-
Customer Accounts											
Customer	PTIS	PTISCAC	CUST04	$	- $	- $	- $	- $	- $	- $	-
Customer Service											
Customer	PTIS	PTISCSC	CUST05	$	- $	- $	- $	- $	- $	- $	-
Total		PLT		$	180,340,159 $	93,939,761 $	21,762,124 $	36,865,489 $	5,996,952 $	5,784,757 $	15,991,076

DELTA NATU. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base										
Gas Supply Costs										
Demand	NCRB	RBGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	NCRB	RBSD	DEM02	$ 21,666,046	$ 10,051,659	$ 3,199,236	$ 8,415,150	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	32,330	$ 14,289	$ 4,722	$ 13,319	$ -	$ -	$ -
Total Storage				$ 21,698,376	$ 10,065,949	$ 3,203,959	$ 8,428,469	$ -	$ -	$ -
Transmission										
Demand	NCRB	RBTD	TDEM	$ 34,615,060	$ 9,653,032	$ 3,063,128	$ 7,545,613	$ 1,552,770	$ 3,182,074	$ 9,618,444
Commodity	NCRB	RBTC	COM03	34,669	$ 3,599	$ 1,168	$ 4,468	$ 2,534	$ 5,663	$ 17,236
Total Transmission				$ 34,649,729	$ 9,656,631	$ 3,064,296	$ 7,550,082	$ 1,555,304	$ 3,187,737	$ 9,635,680
Distribution Expenses										
Commodity	NCRB	RBDEC	COM04	$ 8,836	$ 2,606	$ 846	$ 3,235	$ 1,835	$ 314	$ -
Distribution Structures & Equipment										
Demand	NCRB	RBDSD	DEM04	$ 1,515,862	$ 663,412	$ 210,516	$ 518,578	$ 106,715	$ 16,640	$ -

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base (Continued)											
Distribution Mains											
Demand	NCRB	RBDMD	DEM05	$	17,901,507 $	7,834,541 $	2,486,079 $	6,124,129 $	1,260,251 $	196,507 $	-
Customer	NCRB	RBDMC	CUST01		23,289,259 $	19,932,530 $	2,792,676 $	540,142 $	23,298 $	613 $	-
Total Distribution Mains					41,190,766 $	27,767,071 $	5,278,755 $	6,664,271 $	1,283,548 $	197,120 $	-
Services											
Customer	NCRB	RBSC	CUST02	$	8,520,666 $	6,165,062 $	1,748,194 $	580,399 $	25,034 $	1,976 $	-
Meters											
Customer	NCRB	RBMC	CUST03	$	11,132,896 $	6,772,292 $	1,100,119 $	2,567,088 $	615,175 $	78,222 $	-
Customer Accounts											
Customer	NCRB	RBCAC	CUST04	$	220,794 $	174,835 $	24,064 $	20,504 $	652 $	87 $	652
Customer Service											
Customer	NCRB	RBCSC	CUST05	$	344 $	294 $	41 $	9 $	0 $	0 $	-
Total		RBT		$	118,938,270 $	61,268,154 $	14,630,788 $	26,332,635 $	3,588,264 $	3,482,097 $	9,636,332

DELTA NATUR. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Operation and Maintenance Expenses										
Gas Supply Costs										
Demand	OMT	OMGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	OMT	OMSD	DEM02	$ 376,007	$ 174,443	$ 55,522	$ 146,042	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	257,240	$ 113,694	$ 37,573	$ 105,973	$ -	$ -	$ -
Total Storage		OMST		$ 633,246	$ 288,137	$ 93,095	$ 252,015	$ -	$ -	$ -
Transmission										
Demand	OMT	OMTD	TDEM	$ 2,802,949	$ 781,653	$ 248,036	$ 611,005	$ 125,735	$ 257,668	$ 778,852
Commodity	OMT	OMTC	COM03	275,846	$ 28,639	$ 9,294	$ 35,553	$ 20,162	$ 45,060	$ 137,139
Total Transmission		OMTRT		$ 3,078,795	$ 810,292	$ 257,330	$ 646,557	$ 145,897	$ 302,728	$ 915,991
Distribution Expenses										
Commodity	OMT	OMDEC	COM04	$ 70,306	$ 20,737	$ 6,730	$ 25,742	$ 14,598	$ 2,499	$ -
Distribution Structures & Equipment										
Demand	OMT	OMDSD	DEM04	$ 145,166	$ 63,532	$ 20,160	$ 49,662	$ 10,220	$ 1,594	$ -

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Operation and Maintenance Expenses (Continued)											
Distribution Mains											
Demand	OMT	OMDMD	DEM05	$	1,721,636 $	753,469 $	239,093 $	588,974 $	121,202 $	18,899 $	-
Customer	OMT	OMDMC	CUST01		2,239,790 $	1,916,965 $	268,579 $	51,947 $	2,241 $	59 $	-
Total Distribution Mains					3,961,426 $	2,670,433 $	507,672 $	640,921 $	123,442 $	18,958 $	-
Services											
Customer	OMT	OMSC	CUST02	$	766,364 $	554,497 $	157,236 $	52,202 $	2,252 $	178 $	-
Meters											
Customer	OMT	OMMC	CUST03	$	1,087,545 $	661,568 $	107,468 $	250,772 $	60,095 $	7,641 $	-
Customer Accounts											
Customer	OMT	OMCAC	CUST04	$	1,756,764 $	1,391,087 $	191,467 $	163,138 $	5,190 $	692 $	5,190
Customer Service											
Customer	OMT	OMCSC	CUST05	$	2,737 $	2,343 $	322 $	69 $	2 $	0 $	-
Total		OMTT		$	11,502,349 $	6,462,625 $	1,341,480 $	2,081,078 $	361,696 $	334,289 $	921,181

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Payroll Expenses											
Gas Supply Costs											
Demand	LBTOT	LBGSD	DEM01	$	- $	- $	- $	- $	- $	- $	-
Commodity	LBTOT	LBGSC	COM01		- $	- $	- $	- $	- $	- $	-
Total Procurement Expenses		LBGST		$	- $	- $	- $	- $	- $	- $	-
Storage											
Demand	LBTOT	LBSD	DEM02	$	130,590 $	60,586 $	19,283 $	50,722 $	- $	- $	-
Commodity	LBTOT	LBSC	COM02		63,847 $	28,219 $	9,326 $	26,302 $	- $	- $	-
Total Storage		LBST		$	194,437 $	88,804 $	28,609 $	77,024 $	- $	- $	-
Transmission											
Demand	LBTOT	LBTD	TDEM	$	1,889,995 $	527,059 $	167,248 $	411,993 $	84,782 $	173,742 $	525,171
Commodity	LBTOT	LBTC	COM03		157,677 $	16,370 $	5,313 $	20,322 $	11,525 $	25,757 $	78,390
Total Transmission		LBTRT		$	2,047,672 $	543,430 $	172,561 $	432,316 $	96,307 $	199,499 $	603,561
Distribution Expenses											
Commodity	LBTOT	LBDEC	COM04	$	- $	- $	- $	- $	- $	- $	-
Distribution Structures & Equipment											
Demand	LBTOT	LBDSD	DEM04	$	84,344 $	36,913 $	11,713 $	28,854 $	5,938 $	926 $	-

DELTA NATUR GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Payroll Expenses																	
Distribution Mains																	
Demand	LBTOT	LBDMD	DEM05	$	1,072,603	$	469,421	$	148,958	$	366,939	$	75,510	$	11,774	$	-
Customer	LBTOT	LBDMC	CUST01		1,395,420	$	1,194,295	$	167,328	$	32,364	$	1,396	$	37	$	-
Total Distribution Mains					2,468,023	$	1,663,717	$	316,287	$	399,302	$	76,906	$	11,811	$	-
Services																	
Customer	LBTOT	LBSC	CUST02	$	474,949	$	343,646	$	97,446	$	32,352	$	1,395	$	110	$	-
Meters																	
Customer	LBTOT	LBMC	CUST03	$	653,285	$	397,402	$	64,556	$	150,638	$	36,099	$	4,590	$	-
Customer Accounts																	
Customer	LBTOT	LBCAC	CUST04	$	843,051	$	667,566	$	91,883	$	78,288	$	2,491	$	332	$	2,491
Customer Service																	
Customer	LBTOT	LBCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		LBTT		$	6,765,762	$	3,741,478	$	783,054	$	1,198,775	$	219,135	$	217,268	$	606,051

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Depreciation Expenses										
Gas Supply Costs										
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	DEPREX	DESD	DEM02	$ 272,969	$ 126,640	$ 40,307	$ 106,022	$ -	$ -	$ -
Commodity	DEPREX	DESC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		DEST		$ 272,969	$ 126,640	$ 40,307	$ 106,022	$ -	$ -	$ -
Transmission										
Demand	DEPREX	DETD	TDEM	$ 1,292,154	$ 360,340	$ 114,344	$ 281,672	$ 57,964	$ 118,784	$ 359,049
Commodity	DEPREX	DETC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		DETT		$ 1,292,154	$ 360,340	$ 114,344	$ 281,672	$ 57,964	$ 118,784	$ 359,049
Distribution Expenses										
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	DEPREX	DEDSD	DEM04	$ 65,118	$ 28,499	$ 9,043	$ 22,277	$ 4,584	$ 715	$ -

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Depreciation Expenses (Continued)											
Distribution Mains											
Demand	DEPREX	DEDMD	DEM05	$	747,809 $	327,277 $	103,852 $	255,827 $	52,645 $	8,209 $	-
Customer	DEPREX	DEDMC	CUST01		972,875 $	832,652 $	116,660 $	22,564 $	973 $	26 $	-
Total Distribution Mains					1,720,684 $	1,159,929 $	220,512 $	278,390 $	53,618 $	8,234 $	-
Services											
Customer	DEPREX	DESC	CUST02	$	351,207 $	254,113 $	72,058 $	23,923 $	1,032 $	81 $	-
Meters											
Customer	DEPREX	DEMC	CUST03	$	532,606 $	323,991 $	52,630 $	122,811 $	29,430 $	3,742 $	-
Customer Accounts											
Customer	DEPREX	DECAC	CUST04	$	- $	- $	- $	- $	- $	- $	-
Customer Service											
Customer	DEPREX	DECSC	CUST05	$	- $	- $	- $	- $	- $	- $	-
Total		DET		$	4,234,739 $	2,253,513 $	508,895 $	835,096 $	146,629 $	131,557 $	359,049

DELTA NATU.   GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Other Taxes										
Gas Supply Costs										
Demand	OTT	OTTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OTTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	OTT	OTTSD	DEM02	$ 130,765	$ 60,667	$ 19,309	$ 50,790	$ -	$ -	$ -
Commodity	OTT	OTTSC	COM02	5,104	$ 2,256	$ 746	$ 2,103	$ -	$ -	$ -
Total Storage		OTTST		$ 135,870	$ 62,923	$ 20,055	$ 52,892	$ -	$ -	$ -
Transmission										
Demand	OTT	OTTTD	TDEM	$ 549,874	$ 153,342	$ 48,659	$ 119,865	$ 24,666	$ 50,549	$ 152,793
Commodity	OTT	OTTTC	COM03	12,606	$ 1,309	$ 425	$ 1,625	$ 921	$ 2,059	$ 6,267
Total Transmission		OTTTT		$ 562,480	$ 154,651	$ 49,084	$ 121,490	$ 25,588	$ 52,608	$ 159,060
Distribution Expenses										
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	OTT	OTTDSD	DEM04	$ 23,940	$ 10,477	$ 3,325	$ 8,190	$ 1,685	$ 263	$ -

DELTA NATUR. .AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Other Taxes (Continued)											
Distribution Mains											
Demand	OTT	OTTDMD	DEM05	$	288,788 $	126,387 $	40,106 $	98,795 $	20,330 $	3,170 $	-
Customer	OTT	OTTDMC	CUST01		375,703 $	321,552 $	45,052 $	8,714 $	376 $	10 $	-
Total Distribution Mains					664,491 $	447,940 $	85,157 $	107,508 $	20,706 $	3,180 $	-
Services											
Customer	OTT	OTTSC	CUST02	$	134,806 $	97,538 $	27,658 $	9,183 $	396 $	31 $	-
Meters											
Customer	OTT	OTTMC	CUST03	$	178,494 $	108,580 $	17,638 $	41,158 $	9,863 $	1,254 $	-
Customer Accounts											
Customer	OTT	OTTCAC	CUST04	$	67,400 $	53,371 $	7,346 $	6,259 $	199 $	27 $	199
Customer Service											
Customer	OTT	OTTCSC	CUST05	$	- $	- $	- $	- $	- $	- $	-
Total		OTTT		$	1,767,481 $	935,479 $	210,262 $	346,680 $	58,438 $	57,362 $	159,259

DELTA NATUI ЗAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense										
Gas Supply Costs										
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	INT	INTSD	DEM02	$ 487,325	$ 226,088	$ 71,959	$ 189,278	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		INTST		$ 487,325	$ 226,088	$ 71,959	$ 189,278	$ -	$ -	$ -
Transmission										
Demand	INT	INTTD	TDEM	$ 1,615,059	$ 450,388	$ 142,919	$ 352,061	$ 72,449	$ 148,468	$ 448,775
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		INTTT		$ 1,615,059	$ 450,388	$ 142,919	$ 352,061	$ 72,449	$ 148,468	$ 448,775
Distribution Expenses										
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	INT	INTDSD	DEM04	$ 69,647	$ 30,481	$ 9,672	$ 23,826	$ 4,903	$ 765	$ -

DELTA NATU. ЗAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense (Continued)											
Distribution Mains											
Demand	INT	INTDMD	DEM05	$	822,308 $	359,881 $	114,198 $	281,313 $	57,890 $	9,027 $	-
Customer	INT	INTDMC	CUST01		1,069,795 $	915,604 $	128,282 $	24,812 $	1,070 $	28 $	-
Total Distribution Mains					1,892,104 $	1,275,484 $	242,480 $	306,124 $	58,960 $	9,055 $	-
Services											
Customer	INT	INTSC	CUST02	$	392,190 $	283,766 $	80,466 $	26,715 $	1,152 $	91 $	-
Meters											
Customer	INT	INTMC	CUST03	$	511,381 $	311,080 $	50,533 $	117,917 $	28,258 $	3,593 $	-
Customer Accounts											
Customer	INT	INTCAC	CUST04	$	- $	- $	- $	- $	- $	- $	-
Customer Service											
Customer	INT	INTCSC	CUST05	$	- $	- $	- $	- $	- $	- $	-
Total		INTT		$	4,967,706 $	2,577,287 $	598,029 $	1,015,922 $	165,722 $	161,972 $	448,775

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period										
Operating Revenues										
Sales and Transportation		REVUC	R01	25,395,331	11,599,893	3,391,784	5,685,582	1,625,063	608,063	2,484,947
Collection Fees		COLFEE	COLL	$ 137,310	$ 124,139	$ 12,285	$ 886	$ 886 → $ -	$ -	$ -
Reconnect Revenue		RCTREV	RCNCT	$ 113,896	$ 97,954	$ 15,030	$ 864	$ 48	$ -	$ -
Bad Check Revenue		BDCH	BDCK	$ 10,095	$ 9,035	$ 970	$ 90	$ -	$ -	$ -
Total Operating Revenues -- Per Books		TOR		$ 25,656,632	$ 11,831,021	$ 3,420,069	$ 5,687,422	$ 1,625,110	$ 608,063	$ 2,484,947
Pro-Forma Adjustments to Revenues										
Temperature normalization		REVADJ1		$ 106,453	$ (53,005)	$ (6,064)	$ 163,640	$ 1,882	$ -	$ -
Total Revenue Adjustments				$ 106,453	$ (53,005)	$ (6,064)	$ 163,640	$ 1,882	$ -	$ -
Total Adjusted Revenue				$ 25,763,085	$ 11,778,016	$ 3,414,004	$ 5,851,062	$ 1,626,992	$ 608,063	$ 2,484,947
Expenses										
Operation and Maintenance Expenses				$ 11,502,349	$ 6,462,625	$ 1,341,480	$ 2,081,078	$ 361,696	$ 334,289	$ 921,181
Depreciation and Amortization Expenses				$ 4,234,739	2,253,513	508,895	835,096	146,629	131,557	359,049
Other Taxes				$ 1,767,481	935,479	210,262	346,680	58,438	57,362	159,259
Total Operating Expenses		TOE		$ 17,504,569	$ 9,651,617	$ 2,060,637	$ 3,262,854	$ 566,762	$ 523,209	$ 1,439,489

DELTA NATUI ,AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period (Cont.)										
Pro-Forma Adjustments to Expenses										
Labor Adjustment	EXADJ1	LBTT		$ 52,914	$ 29,262	$ 6,124	$ 9,375	$ 1,714	$ 1,699	$ 4,740
Eliminate Advedrtising Expenses	EXADJ2	REVUC		(2,264)	$ (1,034)	$ (302)	$ (507)	$ (145)	$ (54)	$ (222)
Lobbying Expense	EXADJ3	REVUC		(26,488)	$ (12,099)	$ (3,538)	$ (5,930)	$ (1,695)	$ (634)	$ (2,592)
Community Relations	EXADJ4	REVUC		(22,664)	$ (10,352)	$ (3,027)	$ (5,074)	$ (1,450)	$ (543)	$ (2,218)
Marketing	EXADJ5	OMTT		(3,973)	$ (2,232)	$ (463)	$ (719)	$ (125)	$ (115)	$ (318)
Rate Case Expenses	EXADJ6	OMTT		33,700	$ 18,934	$ 3,930	$ 6,097	$ 1,060	$ 979	$ 2,699
Depreciation Expenses	EXADJ7	DET		292,968	$ 155,903	$ 35,206	$ 57,774	$ 10,144	$ 9,101	$ 24,840
Payroll Tax	EXADJ8	LBTT		3,910	$ 2,162	$ 453	$ 693	$ 127	$ 126	$ 350
Total Expense Adjustments	ADJTOT			$ 328,103	$ 180,543	$ 38,383	$ 61,709	$ 9,629	$ 10,559	$ 27,279
Net Income Before Income Taxes				$ 7,930,413	$ 1,945,856	$ 1,314,984	$ 2,526,499	$ 1,050,601	$ 74,295	$ 1,018,178
Income Taxes		TXINC		$ 1,138,000	$ (315,241)	$ 286,093	$ 608,851	$ 364,834	$ (38,332)	$ 231,797
Net Operating Income (Adjusted)	TOM			$ 6,792,413	$ 2,261,097	$ 1,028,892	$ 1,917,649	$ 685,767	$ 112,627	$ 786,382
Net Cost Rate Base				$ 118,938,270	$ 61,268,154	$ 14,630,788	$ 26,332,635	$ 3,588,264	$ 3,482,097	$ 9,636,332
Rate of Return -- Actual				5.71%	3.69%	7.03%	7.28%	19.11%	3.23%	8.16%

DELTA NATU. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted For Increase										
Test Year Operating Income				$ 6,792,413	$ 2,261,097	$ 1,028,892	$ 1,917,649	$ 685,767	$ 112,627	$ 786,382
Proposed Increase				$ 5,563,328	$ 3,847,603	489,441	$ 1,130,709	$ -	$ -	$ 95,575
Increase To Misc Revenue			RCNCT	$ 79,309	$ 70,401	$ 8,340	$ 556	$ 12	$ -	$ -
Total Increase		CLSINC		$ 5,642,637	$ 3,918,004	$ 497,781	$ 1,131,265	$ 12	$ -	$ 95,575
Incremental Income Taxes (@39.4445)			CLSINC	1,941,555	$ 1,348,132	$ 171,280	$ 389,253	$ 4	$ -	$ 32,886
Net Operating Income Adjusted for Increase				10,493,495	4,830,969	1,355,393	2,659,661	685,775	112,627	849,071
Net Cost Rate Base				$ 118,938,270	$ 61,268,154	$ 14,630,788	$ 26,332,635	$ 3,588,264	$ 3,482,097	$ 9,636,332
Rate of Return -- Proposed				8.82%	7.88%	9.26%	10.10%	19.11%	3.23%	8.81%

DELTA NATUR. ɹAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors			$	3,079,555						
				3079555 $	-					
Commodity										
Procurement Expenses		COM01		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
					0.103823	0.033693	0.128885			
Storage (Dec thru March)		COM02		2,671,021	1,180,526	390,137	1,100,357	-	-	-
Transmission		COM03		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
Distribution		COM04		6,036,593	1,780,480	577,814	2,210,287	1,253,445	214,567	-
				-	-	-	-	-	-	-
Demand										
Procurement Expenses		DEM01		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Storage		DEM02		1.00000	0.463936	0.147661	0.388403	-	-	-
					0.463936	0.147661	0.388403			
Transmission		DEM03		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Distribution Structures		DEM04		53,566	23,443	7,439	18,325	3,771	588	-
Distribution Mains		DEM05		53,566	23,443	7,439	18,325	3,771	588	-
Customer										
Distribution Mains (Year-end Customers)		CUST01		37,986	32,511	4,555	881	38	1	-
Services		CUST02		13,391,413	9,689,253	2,747,530	912,179	39,345	3,106	-
Meters		CUST03		5,849,497	3,558,329	578,030	1,348,811	323,228	41,100	-
Customer Count (Average)				37,568	32,164	4,427	943	30	4	-
Customer Accounts		CUST04		40,619	32,164	4,427	3,772	120	16	120
Customer Service		CUST05		37,568	32,164	4,427	943	30	4	-
Forfeited Discounts		REVFD		2,641,717	2,168,773	432,108	9,080	2,703	18,740	9,961

DELTA NATU. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors Continued										
Taxable Income Actual										
Net Income Before Income Tax	NIBIT		$	7,930,413 $	1,945,856 $	1,314,984 $	2,526,499 $	1,050,601 $	74,295 $	1,018,178
Interest Expense	INT	PLT	$	4,967,706 $	2,587,694 $	599,466 $	1,015,508 $	165,194 $	159,349 $	440,495
Interest Adjustment		PLT	$	224,173 $	116,772 $	27,052 $	45,826 $	7,455 $	7,191 $	19,878
Taxable Income	TXINC		$	2,738,534 $	(758,611) $	688,467 $	1,465,165 $	877,952 $	(92,245) $	557,805
Meter Allocation										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service					109.45	126.9	1531	8506	13700	
Meter Cost				5,849,497	3,558,329	578,030	1,348,811	323,228	41,100	-
Service Line Allocation										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service					298.03	603.19	1035.39	1035.39	1035.39	0
Service Cost				13,391,413	9,689,253	2,747,530	912,179	39,345	3,106	-
Collection Fees	COLL			1.00000	0.90408	0.08947	0.00645			
Reconnect Revenue	RCNCT			1.00000	0.86003	0.13196	0.00759	0.00042		
Bad Check Fees	BDCK			1.00000	0.89500	0.09608	0.00892			
Customer Deposits	CSTDEP			1.00000	0.89690	0.08960	0.00980	0.00370		
Transmission Allocator										
Transmission Demand Allocator				84,012	23,443	7,439	18,325	3,771	7,675	23,359
Transmission Plant			$	57,549,027						
Specific Assignment			$	36,192.40				$	36,192.40	
Residual Transmission Plant		DEM03		57,512,834 $	16,048,581 $	5,092,582 $	12,544,907 $	2,581,547 $	5,254,142 $	15,991,076
Total Allocation of Transmission Plant			$	57,549,027 $	16,048,580.89 $	5,092,581.72 $	12,544,906.58 $	2,581,546.67 $	5,290,334.72 $	15,991,076.27
Transmission Allocator	TDEM			1.000000	0.27886798	0.088491187	0.217986424	0.044858216	0.09192744	0.277868752

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Customer Related Unit Cost										
Rate Base				$ 43,163,959	$ 33,045,014	$ 5,665,093	$ 3,708,141	$ 664,160	$ 80,899	$ 652
Rate of Return				8.82%	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%
Return				$ 3,808,201	$ 2,915,443	$ 499,811	$ 327,156	$ 58,596	$ 7,137	$ 58
Income Taxes				$ 413,143	$ (170,043)	$ 110,791	$ 85,763	$ 67,610	$ (892)	$ 16
Operation and Maintenance Expenses				5,853,199	4,526,459	725,072	518,128	69,779	8,570	5,190
Depreciation Expenses				1,856,688	1,410,757	241,348	169,298	31,436	3,849	-
Other Taxes				756,403	581,041	97,694	65,313	10,834	1,322	199
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				158,805	121,947	19,825	14,243	1,907	278	103
Total Customer-Related Revenue Requirement				$ 12,846,440	$ 9,385,605	$ 1,694,541	$ 1,179,902	$ 240,162	$ 20,265	$ 5,565
Less: Misc Service Revenues				(49,687)	(61,617)	(6,930)	(163)	(9)	-	-
Net Revenue Requirement				$ 12,796,754	$ 9,323,988	$ 1,687,612	$ 1,179,739	$ 240,153	$ 20,265	$ 5,565
Customer-Months				37,568	32,164	4,427	943	30	4	-
Customer-Related Unit Cost ($/Cust/Mo)				28.386	24.157	31.767	104.254	667.092	422.193	

Seelye Exhibit 7

Class Cost of Service Study

Storage Allocation Factor

DELTA NATUF GAS COMPANY

Summary of Allocation of U..uerground Storage Investment

Calculation of Maximum Class Demands
On February 10th Design Day Assuming 68 Degree Days
For Determination of Demand Allocation Factors

	Total	Residential	Small Non Residential GS	Large Non Residential GS
Non-Temp Sensitive Load (per Day)	4,463	799	299	3,365
Temp Sensitive Load (per Degree Day)	658	333	105	220
Calculated Daily Requirements at -3 Degrees	49,207	23,443	7,439	18,325
Percentage of Total		47.64%	15.12%	37.24%

Allocation of Underground Storage

	Storage Withdrawals	Residential	Small Non Residential GS	Large Non Residential GS
Total Allocated Withdrawals Thru February 9th				
December	459,865	204,059	65,268	190,538
January	497,654	224,372	71,635	201,647
Feb. 1-9	154,733	69,269	22,134	63,330
Total	1,112,252	497,700	159,037	455,515
Balance of Working Gas Allocated on the Basis of -3 Degree Feb. 10 Design Day	1,469,337	699,992	222,164	547,181
Total Working Gas	2,581,589	1,197,692	381,201	1,002,696
Total Allocation Factor For Underground Storage	1.000000	0.463936	0.147661	0.388403

DELTA NATU GAS COMPANY
Allocation of Under nd Storage Investment

(December)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	24	8,791	2,819	8,645	20,255	13,649	5,924	1,900	5,825
2	24	8,791	2,819	8,645	20,255	12,537	5,441	1,745	5,351
3	24	8,791	2,819	8,645	20,255	12,556	5,450	1,748	5,359
4	25	9,124	2,924	8,865	20,913	13,466	5,875	1,883	5,708
5	26	9,457	3,029	9,085	21,571	13,859	6,076	1,946	5,837
6	26	9,457	3,029	9,085	21,571	13,994	6,135	1,965	5,894
7	26	9,457	3,029	9,085	21,571	14,387	6,307	2,020	6,059
8	26	9,457	3,029	9,085	21,571	14,388	6,308	2,020	6,060
9	26	9,457	3,029	9,085	21,571	14,390	6,309	2,021	6,061
10	27	9,790	3,134	9,305	22,229	14,391	6,338	2,029	6,024
11	27	9,790	3,134	9,305	22,229	13,950	6,144	1,967	5,839
12	28	10,123	3,239	9,525	22,887	14,342	6,344	2,030	5,969
13	28	10,123	3,239	9,525	22,887	14,343	6,344	2,030	5,969
14	29	10,456	3,344	9,745	23,545	14,735	6,543	2,093	6,098
15	29	10,456	3,344	9,745	23,545	14,735	6,543	2,093	6,098
16	29	10,456	3,344	9,745	23,545	14,753	6,551	2,095	6,106
17	29	10,456	3,344	9,745	23,545	14,753	6,551	2,095	6,106
18	30	10,789	3,449	9,965	24,203	15,144	6,751	2,158	6,235
19	30	10,789	3,449	9,965	24,203	15,144	6,751	2,158	6,235
20	31	11,122	3,554	10,185	24,861	15,535	6,950	2,221	6,364
21	31	11,122	3,554	10,185	24,861	15,483	6,927	2,213	6,343
22	31	11,122	3,554	10,185	24,861	15,483	6,927	2,213	6,343
23	31	11,122	3,554	10,185	24,861	15,874	7,102	2,269	6,503
24	31	11,122	3,554	10,185	24,861	15,874	7,102	2,269	6,503
25	32	11,455	3,659	10,405	25,519	15,874	7,126	2,276	6,472
26	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
27	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
28	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
29	32	11,455	3,659	10,405	25,519	16,069	7,213	2,304	6,552
30	33	11,788	3,764	10,625	26,177	16,069	7,236	2,311	6,522
31	33	11,788	3,764	10,625	26,177	16,069	7,236	2,311	6,522
Total	894	322,471	103,139	300,995	726,605	459,867	204,059	65,268	190,538

DELTA NATU' GAS COMPANY
Allocation of Underg .ıd Storage Investment

(January)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	32	11,455	3,659	10,405	25,519	15,613	7,008	2,239	6,366
2	32	11,455	3,659	10,405	25,519	15,586	6,996	2,235	6,355
3	32	11,455	3,659	10,405	25,519	15,602	7,004	2,237	6,362
4	32	11,455	3,659	10,405	25,519	15,596	7,001	2,236	6,359
5	33	11,788	3,764	10,625	26,177	15,602	7,026	2,243	6,333
6	33	11,788	3,764	10,625	26,177	15,728	7,083	2,262	6,384
7	33	11,788	3,764	10,625	26,177	15,727	7,082	2,261	6,384
8	33	11,788	3,764	10,625	26,177	15,734	7,085	2,262	6,386
9	33	11,788	3,764	10,625	26,177	15,731	7,084	2,262	6,385
10	33	11,788	3,764	10,625	26,177	15,722	7,080	2,261	6,382
11	33	11,788	3,764	10,625	26,177	15,745	7,090	2,264	6,391
12	33	11,788	3,764	10,625	26,177	15,720	7,079	2,260	6,381
13	33	11,788	3,764	10,625	26,177	15,712	7,076	2,259	6,377
14	33	11,788	3,764	10,625	26,177	15,681	7,062	2,255	6,365
15	33	11,788	3,764	10,625	26,177	15,720	7,079	2,260	6,381
16	33	11,788	3,764	10,625	26,177	16,115	7,257	2,317	6,541
17	33	11,788	3,764	10,625	26,177	16,107	7,253	2,316	6,538
18	33	11,788	3,764	10,625	26,177	16,109	7,254	2,316	6,539
19	33	11,788	3,764	10,625	26,177	16,133	7,265	2,320	6,548
20	33	11,788	3,764	10,625	26,177	16,112	7,256	2,317	6,540
21	34	12,121	3,869	10,845	26,835	15,992	7,224	2,306	6,463
22	34	12,121	3,869	10,845	26,835	15,999	7,227	2,307	6,466
23	34	12,121	3,869	10,845	26,835	16,000	7,227	2,307	6,466
24	34	12,121	3,869	10,845	26,835	16,390	7,403	2,363	6,624
25	34	12,121	3,869	10,845	26,835	16,390	7,403	2,363	6,624
26	34	12,121	3,869	10,845	26,835	16,523	7,463	2,382	6,677
27	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
28	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
29	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
30	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
31	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
Total	1,035	369,424	117,944	332,015	819,383	497,654	224,372	71,635	201,647

DELTA NATU' GAS COMPANY
Allocation of Undergr und Storage Investment

(February)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	33	11,788	3,764	10,625	26,177	16,348	7,362	2,351	6,636
2	33	11,788	3,764	10,625	26,177	16,321	7,350	2,347	6,625
3	32	11,455	3,659	10,405	25,519	15,952	7,160	2,287	6,504
4	32	11,455	3,659	10,405	25,519	15,560	6,984	2,231	6,344
5	31	11,122	3,554	10,185	24,861	15,180	6,791	2,170	6,219
6	31	11,122	3,554	10,185	24,861	15,306	6,847	2,188	6,270
7	31	11,122	3,554	10,185	24,861	15,305	6,847	2,188	6,270
8	30	10,789	3,449	9,965	24,203	14,926	6,653	2,127	6,145
9	30	10,789	3,449	9,965	24,203	14,923	6,652	2,127	6,144
10	29	10,456	3,344	9,745	23,545	14,914	6,623	2,118	6,173
Total	312	111,886	35,750	102,290	249,926	154,734	69,269	22,134	63,330

Seelye Exhibit 8

Class Cost of Service Study

Zero Intercept Analysis

Delta Natural Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2006

Weighted Linear Regression Statistics

		Estimate	Standard Error
Size Coefficient ($ per Foot)		0.6639341	0.4074573
Zero Intercept ($ per Foot)		3.3945372	1.1990359
R-Square		0.9193681	

Plant Classification

Total Number of Units		7,705,996
Zero Intercept		3.3945372
Zero Intercept Cost	$	26,158,290
Total Cost of Sample	$	39,749,126
Percentage of Total		0.658084664
Percentage Classified as Customer-Related		65.81%
Percentage Classified as Demand-Related		34.19%

Delta Natural ; Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2006

Description	Pipe Size		Net Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)
Distribution Main Pipe, Under 2" Plastic	1.500	$	2,931,080	508,866	5.76002
Distribution Main Pipe, 2" Plastic	2.000	$	20,799,781	4,504,311	4.61775
Distribution Main Pipe, 3" Plastic	3.000	$	101,306	89,043	1.13772
Distribution Main Pipe, 4" Plastic	4.000	$	10,735,972	1,353,891	7.92972
Distribution Main Pipe, 6" Plastic	6.000	$	558,228	58,933	9.47225
Distribution Main Pipe, Under 2" Steel	1.500	$	188,710	85,824	2.19880
Distribution Main Pipe, 2" Steel	2.000	$	462,919	379,832	1.21875
Distribution Main Pipe, 3" Steel	3.000	$	73,752	61,367	1.20182
Distribution Main Pipe, 4" Steel	4.000	$	2,211,801	291,928	7.57653
Distribution Main Pipe, 6" Steel	6.000	$	1,281,750	277,138	4.62495
Distribution Main Pipe, 8" Steel	8.000	$	403,827	94,863	4.25695
Total		$	39,749,126.00	7,705,996	

Seelye Exhibit 9

Temperature Normalization Adjustment

Delta Natural Gas Company, Inc.
Natural Gas Temperature Normalization Adjustment
For the 12 months Ended December 31, 2003

Consumption Not Billed under the Weather Normalization Clause

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,662	4,667
Actual Heating Degree Days	4,466	4,172
Normal over (under) Actual	196	495

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days **(7 Non-WNA Months)**	712	1,011
Actual Heating Degree Days **(7 Non-WNA Months)**	766	1,103
Normal over (under) Actual	(54)	(92)

	(1) Total Mcf	(2) Non-Temp Mcf	(3) Non-Temp Mcf Full Year	(4) Temperature Sensitive Mcf	(5) Actual Degree Days	(6) Mcf per Degree Days	(7) Normal Degree Days	(8) Departure From Normal	(9) Normal Temperature Adjustment	(10) Net Revenue Per Mcf Sold	(11) Net Revenue Adjustment
			(Column (1) x 6)	(Column (1) - (3))		(Column (4) x (5))		(Column (7) - (5))	(Column (6) x (8))		(Column (9) x (10))
Residential *	350,746	48,520	169,820	180,926	766	236	712	(54)	(12,744)	$ 4.1592	$ (53,004.84)
Small Non-Residential General Service *	104,366	17,766	62,181	42,185	766	55	712	(54)	(2,970)	$ 3.7950	$ (11,271.15)
Large Non-Residential GS - Commercial	781,181	40,889	245,334	535,847	4,466	120	4,662	196	23,520	$ 3.7950	$ 89,258.40
Large Non-Residential GS - Industrial	107,456	4,224	25,344	82,112	4,466	18	4,662	196	3,528	$ 3.7950	$ 13,388.76
Interruptible Service - Commercial	2,564	-	-	2,564	4,466	1	4,662	196	196	$ 1.6000	$ 313.60
Interruptible Service - Industrial	32,652	1,540	9,240	23,412	4,466	5	4,662	196	980	$ 1.6000	$ 1,568.00
Small Non Residential General Service -Transportation	33,317	344	2,063	31,254	4,466	7	4,662	196	1,372	$ 3.7950	$ 5,206.74
Large Non Residential General Service -Transportation	1,321,380	159,543	957,258	364,122	4,466	82	4,662	196	16,072	$ 3.7950	$ 60,993.24
Residential - Transportation	1,103	10	63	1,040	4,466	0	4,662	196	-	$ 4.1592	$ -
	2,734,764	272,836	1,471,303	1,263,461					29,954		$ 106,452.75

* For the seven months May to November only

Seelye Exhibit 10

Year End Customer Adjustment

Not Proposed

Delta Natural Gas Company, Inc.

Adjustment of Gas Re ·es to reflect Year-end Customers
Over Average Numb istomers in Test Period
12 Months Ended D .er 31, 2006

	Average Number of Customers	Customers Served at 12/31/06	Year-End Over (Under) Average (Col. 2 - 1)	Customer Charge	Additional Customer Charge Revenue (Col. 3 x 4)	Weather Normalized Mcf	Average Mcf per Customer (COL. 6 / 1)	Year -End Mcf Adjustment (COL. 7 x 3)	Net Revenue per Mcf Commodity	Additional Revenue Commodity (COL. 8 x 9)	Year-End Revenue Adjustment (COL. 5 + 10)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	32,130	32,498	368	$ 9.80	$ 3,606.40	1,857,139	57.8	21,270	$ 4.1592	$ 88,466.18	$ 92,072.58
Small Non-Residential GS	4,406	4,534	128	$ 20.00	$ 2,560.00	605,173	137.4	17,581	$ 3.7950	$ 66,719.90	$ 69,279.90
Large Non-Residential GS - Retail	928	939	11	$ 72.00	$ 792.00	2,253,407	2,428.2	26,711		$ 59,909.07	$ 60,701.07
First 200 Mcf						772,185		9,150	$ 3.7950	$ 34,724.25	
Next 800 Mcf						431,115		5,111	$ 2.1461	$ 10,968.72	
Next 4,000 Mcf						607,467		7,202	$ 1.3500	$ 9,722.70	
Next 5,000 Mcf						235,080		2,787	$ 0.9500	$ 2,647.65	
Over 10,000 Mcf						207,560		2,461	$ 0.7500	$ 1,845.75	
Interruptible	37	38	1	$ 250.00	$ 250.00	1,254,621	33,908.7	33,909		$ 40,984.20	$ 41,234.20
						326,478		8,824	$ 1.6000	$ 14,118.40	
						657,056		17,758	$ 1.2000	$ 21,309.60	
						214,604		5,800	$ 0.8000	$ 4,640.00	
						56,483		1,527	$ 0.6000	$ 916.20	
On System Transportation Special	4	4	-		$ -	2,801,367	700,341.8	-	$ -	$ -	$ -
	37,505	38,013	508		$ 7,208.40	8,771,707		99,471		$ 256,079.35	$ 263,287.75
Expenses at an Operating Ratio of -				0.3539							93,179
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES											$ 170,108

CALCULATION OF GAS OPERATING RATIO

TOTAL GAS OPERATING EXPENSES	59,234,904
LESS GAS SUPPLY EXPENSES	41,730,337
LESS WAGES AND SALARIES	6,207,165
LESS PENSIONS AND BENEFITS	2,145,052
LESS REGULATORY COMMISSION EXPENSE	163,359
NET EXPENSES	8,988,991
TOTAL GAS OPERATIONS REVENUES (AS BILLED)	67,129,659
LESS GSC REVENUE	41,730,337
NET REVENUE	25,399,322
OPERATING RATIO	0.3539

Seelye Exhibit 11

Depreciation Study

Delta Natural Gas Company, Inc.
Depreciation Study
December 31, 2006

Overview

The purpose of performing a depreciation study is to insure that the depreciation expenses recorded by the utility and included in the cost of service represents a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over the estimated useful life of the assets.

In performing this study, data was compiled showing plant additions, retirements and transfers going back as far as the 1940s. For certain plant accounts, such as distribution mains (Account 376), meters (Account 381), and house regulators (Account 383), data was available going back well into the 1940s. Many other accounts were not utilized until the 1950s, 1960s or later.

Where sufficient data was available, the average service lives ("ASLs") were determined by identifying the survivor curve and associated ASL that best fit the pattern of retirements from the historical data provided by Delta Natural Gas Company, Inc. ("Delta"). In general, the survivor curves and ASLs were identified that produced the lowest sum of square deviations between the actual balances and simulated balances.[1] The simulated balances were determined by applying various survivor curves to the plant additions and transfers for each plant account for which data was available and then computing the resultant plant balances. The sum of square deviations were calculated based on the difference between the computed plant balances and actual plant balances. In selecting a survivor curve and ASL, several goodness-of-fit statistics were examined: (1) sum of squared deviations ("SSD"), (2) conformance index ("CI"), (3) index of variation ("IV"), and (4) retirement experience index ("REI").[2]

Where sufficient data was not available, the ASLs and depreciation accrual rates of neighboring utilities and judgment were used as a guide in developing the proposed depreciation rates.

The survivor curves utilized in this study correspond to the "Iowa" curves that were developed under the direction of Robley Winfrey at Iowa State University, as described in various bulletins and publications.[3] These curves are still the most widely used within the industry.

---

[1] A detailed description of the simulated plant record ("SPR") method is included in *Public Utility Depreciation Practices*, August 1996, published by the National Association of Regulatory Commissioners (NARUC").

[2] Ibid., at pp. 92-97.

[3] See Winfrey, Robley, *Depreciation of Group Properties*, Bulletin 155 (Iowa State University, Engineering Research Institute, reprinted 1969); Winfrey, Robley, *Statistical Analyses of Industrial Property Retirements*, Bulletin 125 (Iowa State University, Engineering Research Institute, revised 1967);

The depreciation accrual rates were calculated using the average service life depreciation procedure, the straight-line method, and the remaining life basis. Using this approach, the remaining life annual accrual for each category of plant was determined by dividing the original cost less book reserve by the average remaining life determined based on the selected survivor curve. The average remaining life is a weighted average derived from the estimated future survivor curve based on the age of the actual plant additions. The annual depreciation amount is determined by dividing the net plant balance to be recovered by the estimated remaining life. The depreciation accrual rate is then calculated by dividing the annual depreciation amount by the plant balance for the account.

A table showing the current and proposed depreciation accrual rates is included in Appendix A. The Summary of Results included in Appendix B shows the plant balances, the survivor curve, ASL, estimated salvage percentage, net salvage amount, depreciation reserve per books, balance to be recovered, estimated remaining life, annual depreciation amount and proposed accrual rate for those plant accounts for which sufficient data were available to estimate ASLs and survivor curves. For those accounts for which sufficient data was not available, only the proposed accrual rates are shown. Historical data and the average remaining life calculations based on the selected survivor curves are included in Appendix C. The results of the study are described below.

Distribution Plant

Account 375 – Distribution Structures and Improvements

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.75%. The survivor curve that best fit the data was the L3 curve with an ASL of 34 years. Using these parameters, the average remaining life is calculated to be 16.4 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $49,873, the recommended accrual rate is 2.67%, which is slightly lower than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 376 – Distribution Mains

Distribution Mains (Account 378) is the account with the largest amount of assets. Delta's records indicated plant additions dating back to 1940. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R3 curve with an ASL of 37 years provided solid results for all four metrics. Using an R3 curve with an ASL of 37 years, the average remaining life is calculated to be 27.0 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $39,749,124, the calculated accrual rate is 2.67%, which is slightly higher than

---

Winfrey, Robley, *Condition – Percent Tables for Depreciation of Unit and Group Properties*, Bulletin 156 (Iowa State University, Engineering Research Institute, reprinted 1970); Marston, Anson, Winfrey, Robley, and Hepstead, Jean C., *Engineering Valuation and Depreciation* (Iowa State University Press, 1963).

the current rate of 2.50%. Although a higher rate could be supported from the data, it is recommended that Delta continue to use the current rate of 2.50%. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 378 – Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.03%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R1 curve with an ASL of 36 years provided solid results for all four metrics. Using an R1 curve with an ASL of 36 years, the average remaining life is calculated to be 26.6 years. The salvage rate is expected to be –10 % for this account due to removal cost. Based on a plant balance of $1,179,793, the recommended accrual rate is 3.27%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 379 – Measuring and Regulator Station Equipment – City Gate

Delta's records indicated plant additions dating back to 1950. The current depreciation accrual rate for this account is 2.96%. An R2 curve was chosen for this plant account because it had good statistical results and is a common curve used for this account in the industry. Using an R2 curve with an ASL of 37 years, the average remaining life is calculated to be 23.0 years. The salvage rate is expected to be –10 % for this account due to removal cost. Based on a plant balance of $351,979, the recommended accrual rate is 3.19%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 380 – Services – Distribution

Because distribution services were recorded as distribution mains (Account 376) for a number of years, there was not sufficient data to develop survivor curves based on Delta's plant additions and retirements for distribution services. Delta is currently using a depreciation accrual rate of 2.50% for Account 380. Because this is the same accrual rate as for distribution mains (Account 376), no change in the accrual rate is recommended. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 381 – Meters

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 2.25%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S1 curve with an ASL of 40 years provided excellent results for all four metrics. Using an S1 curve with an ASL of 40 years, the average remaining life is calculated to be 28.9 years. No salvage is anticipated in the future for this account. Based on a plant balance of $5,867,192, the recommended accrual rate is 2.28%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 382 – Meters & Regulator Installations

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 4.17%. An S1 curve was chosen for this plant account because it had excellent statistical results and is the same curve used for Account 381 Meters. Using an S1 curve with an ASL of 54 years, the average remaining life is calculated to be 26.2 years. The salvage rate is expected to be –45% for this account due to removal cost. Based on a plant balance of $3,708,896, the recommended accrual rate is 4.50%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 383 – House Regulators

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.88%. The S6 curve with an ASL of 28 years was chosen because it produced excellent statistical results and maximized all four of the statistics examined (SSD, CI, IV and REI). Using an S6 curve with an ASL of 28 years, the average remaining life is calculated to be 15.0 years. Salvage is anticipated to be 5%. Based on a plant balance of $1,917,622, the recommended accrual rate is 4.13%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 385 – Industrial Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1956. The current depreciation accrual rate for this account is 2.38%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R1 curve with an ASL of 43 years provided very strong results for all four metrics. Using an R1 curve with an ASL of 43 years, the average remaining life is calculated to be 33.5 years. Salvage is anticipated to be -10% due to removal cost. Based on a plant balance of $1,228,372, the recommended accrual rate is 2.40%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Gathering and Transmission Plant

Account 305 – Structures and Improvements – Manufactured Gas Plant

There is currently no plant balance for this account. The depreciation rate for this account was 2.20%. If additional investment were made in this account, we would recommend using Delta's existing rate of 4.00%.

Account 325 – Gathering Land & Rights

Delta's records indicated plant additions dating back to 1959. The plant balance is $75,987. The current depreciation accrual rate for this account is 3.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment, we are not proposing to modify the existing accrual rate of 3.00%.

Account 327 – Compressor Station Structures

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for this account. Delta is currently using a depreciation accrual rate of 3.00% for Account 327. We are recommending that Delta maintain its current accrual rate of 3.00%. The plant balance is $42,950.

Account 331 – Producing Gas Wells – Well Equipment

Delta's records indicated plant additions dating back to 1969. The plant balance is $7,795. However, the plant in this account is fully depreciated. If additional investment were made in this account, we would recommend using Delta's existing rate of 4.00%.

Account 332 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 2.25% for Account 332, which has a balance of $1,914,741. We are recommending that Delta maintain its current accrual rate of 2.25%.

Account 333 – Gathering Compressor Stations

Delta's records indicated plant additions dating back only to 1986. The plant balance is $818,994. The current depreciation accrual rate for this account is 4.50%. The curve fitting statistics were poor for all survivor curve types. We are recommending that Delta maintain its current accrual rate of 4.00%.

Account 334 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 4.00% for Account 334, which has a balance of $107,270. We are recommending that Delta maintain its current accrual rate of 2.72%.

Account 366 – Structures and Improvements - Transmission

Delta's records indicated plant additions dating back to 1951. The plant balance is $173,215. The current depreciation accrual rate for this account is 2.00%. There has been no salvage experienced for this account and none is anticipated. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Account 367 – Mains - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.22%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R3 curve with an ASL of 43 years provided excellent results for all four metrics. Using an R3 curve with an ASL of 43 years, the average remaining life is calculated to be 30.2 years. No salvage is anticipated for this account. Based on a plant balance of $28,005,604, the recommended accrual rate is 2.24%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 368 – Compressor Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1961. The plant balance is $1,413,310. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Account 369 – Measuring and Regulator Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 3.16%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S3 curve with an ASL of 39 years provided excellent results for all four metrics. Using an S3 curve with an ASL of 39 years, the average remaining life is calculated to be 27.0 years. Salvage is expected to be –10% due to removal cost. Based on a plant balance of $2,273,559, the recommended accrual rate is 3.14%, which is slightly higher than the current rate.

Account 371 – Other Equipment - Transmission

Delta's records indicated plant additions dating back to 1959. The plant balance is $550,019. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Storage Plant

Account 351 -- Storage Structures and Improvements

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.22% for Account 351. An accrual rate of 2.48% is recommended based on an expected remaining life of 32 years. The plant balance is $233,229. The recommended accrual rate is consistent with other utilities in the region.

Account 352 -- Storage Wells

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.34% for Account 352. An accrual rate of 2.19% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $252,152. The recommended accrual rate is consistent with other utilities in the region.

Account 352.1 -- Storage Rights

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.98% for Account 352.1. An accrual rate of 1.85% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $509,180. The recommended accrual rate is consistent with other utilities in the region.

Account 352.2 -- Storage Resevoirs

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.91% for Account 352.2. An accrual rate of 1.78% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $1,069,953. The recommended accrual rate is consistent with other utilities in the region.

Account 352.3 -- Storage Nonrec Natural Gas

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.90% for Account 352.2. An accrual rate of 1.75% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $165,205. The recommended accrual rate is consistent with other utilities in the region.

Account 353 -- Storage Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.17% for Account 352.2. An accrual rate of 2.44% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $3,339,099. The recommended accrual rate is consistent with other utilities in the region.

Account 354 -- Storage Compressor Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.61% for Account 354. An accrual rate of 1.90% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $1,468,661. The recommended accrual rate is consistent with other utilities in the region.

Account 355 -- Storage Measuring and Regulator Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.25% for Account 355. An accrual rate of 2.41% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $280,342. The recommended accrual rate is consistent with other utilities in the region.

Account 356 – Purification Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.16% for Account 356. An accrual rate of 2.02% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $233,131. The recommended accrual rate is consistent with other utilities in the region.

Account 357 – Storage Other Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.15% for Account 357. An accrual rate of 0.53% is recommended based on an expected remaining life of approximately 26 years. The plant balance is $6,524. The recommended accrual rate is consistent with other utilities in the region.

General Plant

Account 390 – Structures and Improvements

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta maintain the use of 2.00% for this account, which is in line with other utilities in the region and is slightly lower than the accrual rate resulting from the best fitting R3 curve with an average life of 32 years.

Account 391 – Office Furniture

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 2.32% for Account 391. It is recommended that Delta reduce the accrual rate to 1.00%, which will be more in line with other utilities in the region.

Account 392 – Autos and Trucks

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta reduce the accrual rate from 7.77% to 8.14% for this account based on an expected remaining life of 2.5 years. This accrual rate is in line with other utilities in the region.

Account 393 – Stores Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta reduce the accrual rate to 2.00%, which is in line with other utilities in the region.

Account 394 – Tools and Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. It is recommended that Delta reduce the accrual rate to 4.00%, which is in line with other utilities in the region.

Account 395 – Laboratory Equipment

Delta's records indicated plant additions dating back to 1957. The current depreciation accrual rate for this account is 7.36%. After reviewing the account we recommend that the depreciation rate be lowered to 5.00%, which is in line with other utilities in the region.

Account 396 – Power Operated Equipment

Delta's records indicated plant additions dating back to 1964. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing to maintain accrual rate of 2.00%.

Account 397 – Communication Equipment

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 6.56% for Account 397. It is recommended that Delta reduce the accrual rate to 5.00%, which will be more in line with other utilities in the region.

Account 398 – Miscellaneous Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. Delta is currently using a depreciation accrual rate of 5.0% for Account 398, which has a balance of $93,747. It is recommended that Delta reduce the accrual rate to 2.0%, which will be more in line with other utilities in the region.

Account 399.1 – Other Tangible Property – Mapping Software

The current depreciation accrual rate for this account is 10.0%. It is recommended that Delta reduce the accrual rate to 4.0%, which will be more in line with other utilities in the region.

Account 399.2 – Other Tangible Property – Computer Software

The current depreciation accrual rate for this account is 20.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta reduce the accrual rate to 10.0%, which will be more in line with other utilities in the region.

Account 399.3 – Other Tangible Property – Computer Equipment

The current depreciation accrual rate for this account is 20.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta reduce the accrual rate to 10.0%, which will be more in line with other utilities in the region.

Appendix A

Delta Natu s Company
Depreci...on Study

Proposed Depreciation Rates

Account		Current Accrual Rate	Proposed Accrual Rate
305	Structures & Improvements - Manufactured Gas Plant	2.20%	2.20%
325	Gathering Land & Rights	3.00%	3.00%
327	Comp Stattion Structures	3.00%	3.00%
331	Producing Gas Wells -- Well Equipment	4.00%	4.00%
332	Gathering Lines	2.25%	2.25%
333	Gathering Compressor Stations	4.00%	4.00%
334	Gathering Measuring and Regulator Station Equipment	2.72%	2.72%
351	Storage Structures and Improvements	2.22%	2.48%
352	Storage Wells	2.34%	2.19%
3521	Storage Rights	1.98%	1.85%
3522	Storage Resevoirs	1.91%	1.78%
3523	Storage Nonrec Natural Gas	1.90%	1.75%
353	Storage Lines	2.17%	2.44%
354	Storage Compressor Stations	1.61%	1.90%
355	Storage Measuring and Regulator Equipment	2.25%	2.41%
356	Purification Equipment	2.16%	2.02%
357	Storage Other Equipment	1.15%	0.53%
3652	Rights of Way	0.00%	0.00%
3653	Land Rights	2.50%	2.50%
366	Structures & Improvements - Transmission	2.00%	2.00%
367	Mains -- Transmission	2.22%	2.24%
368	Compressor Station Equipment -- Transmission	2.00%	2.00%
369	Measuring and Regulator Station Equipment -- Transmission	3.16%	3.14%
371	Other Equipment -- Transmission	2.00%	2.00%
375	Structures and Improvements -- Distribution	2.75%	2.67%
376	Mains -- Distribution	2.50%	2.50%
378	Measuring and Regulator Station Equipment -- Distribution	3.03%	3.27%
379	Measuring and Regulator Station Equipment -- City Gate	2.96%	3.19%
380	Services -- Distribution	2.50%	2.50%
381	Meters	2.25%	2.28%
382	Meter & Regulator Installations	4.17%	4.50%
383	Houes Regulators	3.88%	4.13%
385	Industrial Measuring and Regulator Station Equipment -- Distribution	2.38%	2.40%
390	Structures and Improvements -- General Plant	2.00%	2.00%
391	Office Furniture and Equipment -- General Plant	2.23%	1.00%
392	Transportation Equipment	7.77%	8.14%
393	Stores Equipment	5.00%	2.00%
394	Tools & Equipment	5.00%	4.00%
39401	Comp Nat Gas Stat		
395	Laboratory Equipment	7.36%	5.00%
396	Power Operated Equipment	2.00%	2.00%
397	Communication Equipment	6.56%	5.00%
398	Miscellaneous Equipment	5.00%	2.00%
399.1	Other Tangible Property -- Mapping Costs	10.00%	4.00%
399.2	Other Tangible Property -- Computer Software	20.00%	10.00%
399031	Computerized Office Equipment	20.00%	10.00%
399.3	Computer Hardware	20.00%	10.00%

Appendix B

Delta Natu s Company
Deprecia...on Study

Proposed Depreciation Rates

Account		Plant Balance	Dispersion	ASL	Estimated Salvage %	Net Salvage Amount	Depreciation Book Reserve	Balance To Be Recovered	Estimated Life Remaining	Annual Depreciation Amount	Total Accrual Rate
						$ -					2.20%
305	Structures & Improvements - Manufactured Gas Plant	$ 75,987	O4	41	0%	$ -	$ 52,270	$ 23,717			3.00%
325	Gathering Land & Rights	$ 42,950			0%	$ -	$ 24,418	$ 18,532			3.00%
327	Comp Stattion Structures	7,795	S6	25	0%	$ -	$ 7,795	$ -			4.00%
331	Producing Gas Wells -- Well Equipment	1,914,741	R3	35	0%	$ -	$ 1,233,752	$ 680,989	17.0	$ 40,058	2.25%
332	Gathering Lines	828,752	R1	47	0%	$ -	$ 660,875	$ 167,877			4.00%
333	Gathering Compressor Stations	136,937	R3	31	0%	$ -	$ 69,617	$ 67,321	18.0	$ 3,740	2.72%
334	Gathering Measuring and Regulator Station Equipment	294,116				$ -	$ 60,887	$ 233,229	32.0	$ 7,288	2.48%
351	Storage Structures and Improvements	360,583				$ -	$ 108,431	$ 252,152	32.0	$ 7,880	2.19%
352	Storage Wells	860,396				$ -	$ 351,216	$ 509,180	32.0	$ 15,912	1.85%
3521	Storage Rights	1,881,731				$ -	$ 811,788	$ 1,069,943	32.0	$ 33,436	1.78%
3522	Storage Resevoirs	294,307				$ -	$ 129,102	$ 165,205	32.0	$ 5,163	1.75%
3523	Storage Nonrec Natural Gas	5,091,297				$ -	$ 1,752,198	$ 3,339,099	32.0	$ 104,347	2.44%
353	Storage Lines	2,419,643				$ -	$ 950,982	$ 1,468,661	32.0	$ 45,896	1.90%
354	Storage Compressor Stations	363,662				$ -	$ 83,320	$ 280,342	32.0	$ 8,761	2.41%
355	Storage Measuring and Regulator Equipment	360,432				$ -	$ 127,301	$ 233,131	32.0	$ 7,285	2.02%
356	Purification Equipment	47,209				$ -	$ 40,686	$ 6,524	26.0	$ 251	0.53%
357	Storage Other Equipment	163,626	S3	27	0%	$ -	$ 163,626	$ (0)	26.0	$ (0)	
3652	Rights of Way										2.50%
3653	Land Rights	182,239	R5	49	0%	$ -	$ 74,233	$ 108,006	33.7	$ 3,207	2.00%
366	Structures & Improvements - Transmission	41,447,021	R3	43	0%	$ -	$ 13,441,417	$ 28,005,604	30.2	$ 927,645	2.24%
367	Mains -- Transmission	2,479,974	S4	36	0%	$ -	$ 1,059,244	$ 1,420,730	6.5	$ 218,574	2.00%
368	Compressor Station Equipment -- Transmission	2,678,817	S3	39	-10%	$ (267,881.70)	$ 673,139	$ 2,273,559	27.0	$ 84,175	3.14%
369	Measuring and Regulator Station Equipment -- Transmission	579,896	R1	27	0%	$ -	$ 453,352	$ 126,544	17.6	$ 7,190	2.00%
371	Other Equipment -- Transmission	113,715	L3	34	0%	$ -	$ 63,842	$ 49,873	16.4	$ 3,041	2.67%
375	Structures and Improvements -- Distribution	61,423,134	R3	37	0%	$ -	$ 21,674,010	$ 39,749,124	27.0	$ 1,472,190	2.50%
376	Mains -- Distribution	1,356,370	R1	36	-10%	$ (135,636.98)	$ 312,214	$ 1,179,793	26.6	$ 44,320	3.27%
378	Measuring and Regulator Station Equipment -- Distribution	480,352	R2	37	-10%	$ (48,035.15)	$ 176,408	$ 351,979	23.0	$ 15,290	3.19%
379	Measuring and Regulator Station Equipment -- City Gate	12,658,475					$ 2,272,997	$ 10,385,478			2.50%
380	Services -- Distribution	8,917,576	S1	40	0%	$ -	$ 3,050,384	$ 5,867,192	28.9	$ 203,017	2.28%
381	Meters	3,145,615	S1	40	-45%	$ (1,415,526.56)	$ 852,245	$ 3,708,896	26.2	$ 141,561	4.50%
382	Meter & Regulator Installations	3,093,300	S6	28	5%	$ 154,664.98	$ 1,175,677	$ 1,762,957	15.0	$ 117,530	4.13%
383	Houes Regulators	1,530,217	R1	43	-10%	$ (153,021.70)	$ 454,866	$ 1,228,372	33.5	$ 36,712	2.40%
385	Industrial Measuring and Regulator Station Equipment -- Distribution	5,452,189	R3	32	40%	$ 2,180,875.50	$ 1,541,971	$ 1,729,343	20.0	$ 86,684	2.00%
390	Structures and Improvements -- General Plant	135,672	L0	17	5%	$ 6,783.59	$ 94,318	$ 34,571			1.00%
391	Office Furniture and Equipment -- General Plant	3,868,757	L3	6	30%	$ 1,160,627.00	$ 1,920,928	$ 787,202	2.5	$ 314,881	8.14%
392	Transportation Equipment	36,011	R5	27	0%	$ -	$ 26,487	$ 9,524			2.00%
393	Stores Equipment	629,382	L5	19	5%	$ 31,469.10	$ 205,031	$ 392,882			4.00%
394	Tools & Equipment	283,352					$ 258,732	$ 24,621			
39401	Comp Nat Gas Stat	215,820	L4	14	0%	$ -	$ 131,452	$ 84,368			5.00%
395	Laboratory Equipment	2,779,542	S1	16	40%	$ 1,111,816.92	$ 1,603,045	$ 64,681			2.00%
396	Power Operated Equipment	443,788	S2	14	5%	$ 22,189.38	$ 230,944	$ 190,654			5.00%
397	Communication Equipment	54,238	S0	21	5%	$ 2,711.90	$ 46,607	$ 4,919			2.00%
398	Miscellaneous Equipment	638,509	S6	23	0%	$ -	$ 591,515	$ 46,994			4.00%
399.1	Other Tangible Property -- Mapping Costs	2,525,991	S6	20	0%	$ -	$ 1,728,173	$ 797,818			10.00%
399.2	Other Tangible Property -- Computer Software	255,272					$ 154,077	$ 101,195			10.00%
399031	Computerized Office Equipment	937,029					$ 622,816	$ 314,213			10.00%
399.3	Computer Hardware										

Appendix C

Delta Natur[illegible]s Company
Depreciation Study
As of December 31, 2006
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	49	R5	-	-	0.50	-	-
1941	-	0	49	R5	-	-	0.49	-	-
1942	-	0	49	R5	-	-	0.70	-	-
1943	-	0	49	R5	-	-	0.92	-	-
1944	-	0	49	R5	-	-	1.15	-	-
1945	-	0	49	R5	-	-	1.40	-	-
1946	-	0	49	R5	-	-	1.64	-	-
1947	-	0	49	R5	-	-	1.86	-	-
1948	-	0	49	R5	-	-	2.06	-	-
1949	-	0	49	R5	-	-	2.25	-	-
1950	-	0	49	R5	-	-	2.45	-	-
1951	200	0	49	R5	4	-	2.68	-	11
1952	-	0	49	R5	-	-	2.93	-	-
1953	-	0	49	R5	-	-	3.21	-	-
1954	-	0	49	R5	-	-	3.52	-	-
1955	-	0	49	R5	-	-	3.87	-	-
1956	2,153	0	49	R5	44	-	4.24	-	186
1957	-	0	49	R5	-	-	4.65	-	-
1958	92	0	49	R5	2	-	5.10	-	10
1959	2,000	0	49	R5	41	-	5.58	-	228
1960	339	0	49	R5	7	-	6.10	-	42
1961	250	0	49	R5	5	-	6.66	-	34
1962	604	0	49	R5	12	-	7.26	-	89
1963	-	0	49	R5	-	-	7.89	-	-
1964	707	0	49	R5	14	-	8.56	-	123
1965	395	0	49	R5	8	-	9.26	-	75
1966	1,926	0	49	R5	39	-	10.00	-	393
1967	472	0	49	R5	10	-	10.76	-	104
1968	-	0	49	R5	-	-	11.56	-	-
1969	-	0	49	R5	-	-	12.38	-	-
1970	-	0	49	R5	-	-	13.22	-	-
1971	-	0	49	R5	-	-	14.09	-	-
1972	-	0	49	R5	-	-	14.97	-	-
1973	446	0	49	R5	9	-	15.87	-	144
1974	844	0	49	R5	17	-	16.79	-	289
1975	4,930	0	49	R5	101	-	17.72	-	1,782
1976	-	0	49	R5	-	-	18.66	-	-
1977	(805)	0	49	R5	(16)	-	19.61	-	(322)
1978	-	0	49	R5	-	-	20.58	-	-

Delta Natı ;as Company
Depreciation Study
As of December 31, 2006
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	-	0	49	R5	-	-	21.55	-	-
1980	-	0	49	R5	-	-	22.53	-	-
1981	-	0	49	R5	-	-	23.52	-	-
1982	-	0	49	R5	-	-	24.51	-	-
1983	-	0	49	R5	-	-	25.51	-	-
1984	20,275	0	49	R5	414	-	26.50	-	10,966
1985	3,682	0	49	R5	75	-	27.50	-	2,066
1986	22,873	0	49	R5	467	-	28.50	-	13,304
1987	6,415	0	49	R5	131	-	29.50	-	3,862
1988	44,102	0	49	R5	900	-	30.50	-	27,451
1989	6,213	0	49	R5	127	-	31.50	-	3,994
1990	3,904	0	49	R5	80	-	32.50	-	2,589
1991	-	0	49	R5	-	-	33.50	-	-
1992	1,378	0	49	R5	28	-	34.50	-	970
1993	11,471	0	49	R5	234	-	35.50	-	8,310
1994	1,938	0	49	R5	40	-	36.50	-	1,444
1995	-	0	49	R5	-	-	37.50	-	-
1996	-	0	49	R5	-	-	38.50	-	-
1997	6,959	0	49	R5	142	-	39.50	-	5,610
1998	-	0	49	R5	-	-	40.50	-	-
1999	-	0	49	R5	-	-	41.50	-	-
2000	14,791	0	49	R5	302	-	42.50	-	12,829
2001	11,358	0	49	R5	232	-	43.50	-	10,083
2002	-	0	49	R5	-	-	44.50	-	-
2003	-	0	49	R5	-	-	45.50	-	-
2004	4,838	0	49	R5	99	-	46.50	-	4,591
2005	-	0	49	R5	-	-	47.50	-	-
2006	29,306	0	49	R5	598	-	48.50	-	29,007
	204,056	-			4,164	-	33.68		140,265
				Average Remaining Life					33.7

Survivor Curve	R5
ASL	49

Delta Natur… s Company
Depreciation Study
As of December 31, 2006
367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	43	R3	-	-	1.52	-	-
1941	-	0	43	R3	-	-	1.76	-	-
1942	-	0	43	R3	-	-	2.00	-	-
1943	-	0	43	R3	-	-	2.25	-	-
1944	-	0	43	R3	-	-	2.51	-	-
1945	-	0	43	R3	-	-	2.76	-	-
1946	-	0	43	R3	-	-	3.02	-	-
1947	-	0	43	R3	-	-	3.27	-	-
1948	-	0	43	R3	-	-	3.53	-	-
1949	-	0	43	R3	-	-	3.79	-	-
1950	-	0	43	R3	-	-	4.05	-	-
1951	61,761	0	43	R3	1,436	-	4.31	-	6,189
1952	-	0	43	R3	-	-	4.58	-	-
1953	-	0	43	R3	-	-	4.85	-	-
1954	8,944	0	43	R3	208	-	5.14	-	1,069
1955	95,433	0	43	R3	2,219	-	5.44	-	12,072
1956	153,043	0	43	R3	3,559	-	5.75	-	20,471
1957	2,766	0	43	R3	64	-	6.08	-	391
1958	40,731	0	43	R3	947	-	6.42	-	6,086
1959	209,986	0	43	R3	4,883	-	6.79	-	33,150
1960	443,547	0	43	R3	10,315	-	7.17	-	73,977
1961	-	0	43	R3	-	-	7.58	-	-
1962	11,049	0	43	R3	257	-	8.00	-	2,056
1963	5,069	0	43	R3	118	-	8.45	-	996
1964	43,691	0	43	R3	1,016	-	8.92	-	9,061
1965	401,158	0	43	R3	9,329	-	9.41	-	87,780
1966	185,675	0	43	R3	4,318	-	9.92	-	42,847
1967	42,318	0	43	R3	984	-	10.46	-	10,293
1968	570,758	0	43	R3	13,273	-	11.02	-	146,213
1969	10,242	0	43	R3	238	-	11.59	-	2,761
1970	30,291	0	43	R3	704	-	12.19	-	8,589
1971	390,160	0	43	R3	9,073	-	12.81	-	116,231
1972	220,046	0	43	R3	5,117	-	13.45	-	68,812
1973	20,159	0	43	R3	469	-	14.10	-	6,611
1974	155,219	0	43	R3	3,610	-	14.77	-	53,331
1975	1,038,377	0	43	R3	24,148	-	15.46	-	373,403
1976	667,139	0	43	R3	15,515	-	16.17	-	250,837
1977	32,582	0	43	R3	758	-	16.89	-	12,796
1978	351,269	0	43	R3	8,169	-	17.62	-	143,953

Delta Natura s Company
Depreciation Study
As of December 31, 2006
367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	157,163	0	43	R3	3,655	-	18.37	-	67,142
1980	637,037	0	43	R3	14,815	-	19.13	-	283,440
1981	94,865	0	43	R3	2,206	-	19.91	-	43,919
1982	67,797	0	43	R3	1,577	-	20.70	-	32,629
1983	100,369	0	43	R3	2,334	-	21.50	-	50,173
1984	124,371	0	43	R3	2,892	-	22.31	-	64,521
1985	920,732	0	43	R3	21,412	-	23.13	-	495,299
1986	656,696	0	43	R3	15,272	-	23.97	-	366,022
1987	419,996	0	43	R3	9,767	-	24.81	-	242,361
1988	407,419	0	43	R3	9,475	-	25.67	-	243,228
1989	1,403,591	171586	43	R3	32,642	3,990	26.54	-	866,271
1990	409,629	0	43	R3	9,526	-	27.42	-	261,181
1991	475,208	114998	43	R3	11,051	2,674	28.30	-	312,808
1992	770,645	0	43	R3	17,922	-	29.20	-	523,365
1993	1,311,531	0	43	R3	30,501	-	30.11	-	918,342
1994	1,842,857	172928	43	R3	42,857	4,022	31.02	-	1,329,598
1995	2,576,777	0	43	R3	59,925	-	31.95	-	1,914,438
1996	2,206,080	0	43	R3	51,304	-	32.88	-	1,686,787
1997	983,281	0	43	R3	22,867	-	33.82	-	773,279
1998	1,073,527	0	43	R3	24,966	-	34.76	-	867,842
1999	664,955	4126412	43	R3	15,464	95,963	35.71	20.70	2,538,224
2000	1,951,563	0	43	R3	45,385	-	36.67	-	1,664,257
2001	710,776	0	43	R3	16,530	-	37.63	-	622,044
2002	3,267,444	0	43	R3	75,987	-	38.60	-	2,933,040
2003	4,131,461	0	43	R3	96,080	-	39.57	-	3,801,986
2004	1,777,954	0	43	R3	41,348	-	40.55	-	1,676,506
2005	767,710	0	43	R3	17,854	-	41.53	-	741,388
2006	3,695,479	0	43	R3	85,941	-	42.51	-	3,653,196
	38,798,326	4,585,924			902,287	106,649	33.76		30,463,261
					Average Remaining Life				30.2

Survivor Curve	R3
ASL	43

Delta Natur. .s Company
Depreciation Study
As of December 31, 2006
368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	36	S4	-	-	-	-	-
1941	-	0	36	S4	-	-	-	-	-
1942	-	0	36	S4	-	-	-	-	-
1943	-	0	36	S4	-	-	0.50	-	-
1944	-	0	36	S4	-	-	0.50	-	-
1945	-	0	36	S4	-	-	1.03	-	-
1946	-	0	36	S4	-	-	0.99	-	-
1947	-	0	36	S4	-	-	0.93	-	-
1948	-	0	36	S4	-	-	0.95	-	-
1949	-	0	36	S4	-	-	1.01	-	-
1950	-	0	36	S4	-	-	1.10	-	-
1951	-	0	36	S4	-	-	1.19	-	-
1952	-	0	36	S4	-	-	1.29	-	-
1953	-	0	36	S4	-	-	1.40	-	-
1954	-	0	36	S4	-	-	1.52	-	-
1955	-	0	36	S4	-	-	1.64	-	-
1956	-	0	36	S4	-	-	1.77	-	-
1957	-	0	36	S4	-	-	1.91	-	-
1958	-	0	36	S4	-	-	2.05	-	-
1959	-	0	36	S4	-	-	2.21	-	-
1960	-	0	36	S4	-	-	2.37	-	-
1961	794	0	36	S4	22	-	2.55	-	56
1962	11,090	0	36	S4	308	-	2.73	-	842
1963	89,639	0	36	S4	2,490	-	2.93	-	7,307
1964	2,757	0	36	S4	77	-	3.15	-	241
1965	76,220	0	36	S4	2,117	-	3.38	-	7,163
1966	1,010	0	36	S4	28	-	3.63	-	102
1967	1,745	0	36	S4	48	-	3.90	-	189
1968	-	0	36	S4	-	-	4.20	-	-
1969	3,869	0	36	S4	107	-	4.52	-	485
1970	480	0	36	S4	13	-	4.86	-	65
1971	23,086	0	36	S4	641	-	5.24	-	3,357
1972	309	0	36	S4	9	-	5.64	-	48
1973	-	0	36	S4	-	-	6.08	-	-
1974	958	0	36	S4	27	-	6.56	-	175
1975	57,007	0	36	S4	1,584	-	7.08	-	11,216
1976	43,971	0	36	S4	1,221	-	7.65	-	9,338

Delta Natu as Company
Depreciation Study
As of December 31, 2006
368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1977	-	0	36	S4	-	-	8.25	-	-
1978	600	0	36	S4	17	-	8.90	-	148
1979	14,111	0	36	S4	392	-	9.60	-	3,763
1980	12,740	0	36	S4	354	-	10.34	-	3,661
1981	1,020	0	36	S4	28	-	11.13	-	315
1982	640	0	36	S4	18	-	11.96	-	213
1983	-	0	36	S4	-	-	12.82	-	-
1984	483,934	0	36	S4	13,443	-	13.72	-	184,394
1985	77,490	0	36	S4	2,153	-	14.64	-	31,515
1986	397,226	0	36	S4	11,034	-	15.59	-	171,998
1987	42,436	0	36	S4	1,179	-	16.55	-	19,511
1988	-	0	36	S4	-	-	17.53	-	-
1989	11,796	0	36	S4	328	-	18.52	-	6,067
1990	-	0	36	S4	-	-	19.51	-	-
1991	190,334	0	36	S4	5,287	-	20.50	-	108,403
1992	12,181	0	36	S4	338	-	21.50	-	7,275
1993	(2)	0	36	S4	(0)	-	22.50	-	(1)
1994	8,004	0	36	S4	222	-	23.50	-	5,225
1995	-	0	36	S4	-	-	24.50	-	-
1996	-	0	36	S4	-	-	25.50	-	-
1997	-	0	36	S4	-	-	26.50	-	-
1998	8,440	0	36	S4	234	-	27.50	-	6,447
1999	-	519600	36	S4	-	14,433	28.50	-	-
2000	26,345	0	36	S4	732	-	29.50	-	21,588
2001	-	0	36	S4	-	-	30.50	-	-
2002	6,075	0	36	S4	169	-	31.50	-	5,316
2003	443,449	0	36	S4	12,318	-	32.50		
2004	17,735	0	36	S4	493	-	33.50		
2005	-	0	36	S4	-	-	34.50		
2006	827,361	0	36	S4	22,982	-	35.50		
	2,894,850	519,600			80,412	14,433	7.67		616,424
				Average Remaining Life					6.5

Survivor Curve	S4
ASL	36

Delta Naturɛ ɜ Company
Depreciatıon Study
As of December 31, 2006
369 -- Measuring Regulating Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	39	S3	-	-	1.49	-	-
1941	-	0	39	S3	-	-	1.63	-	-
1942	-	0	39	S3	-	-	1.77	-	-
1943	-	0	39	S3	-	-	1.91	-	-
1944	-	0	39	S3	-	-	2.06	-	-
1945	-	0	39	S3	-	-	2.22	-	-
1946	-	0	39	S3	-	-	2.38	-	-
1947	-	0	39	S3	-	-	2.54	-	-
1948	-	0	39	S3	-	-	2.71	-	-
1949	-	0	39	S3	-	-	2.89	-	-
1950	-	0	39	S3	-	-	3.07	-	-
1951	604	0	39	S3	15	-	3.26	-	50
1952	-	0	39	S3	-	-	3.45	-	-
1953	-	0	39	S3	-	-	3.65	-	-
1954	-	0	39	S3	-	-	3.86	-	-
1955	2,821	0	39	S3	72	-	4.08	-	295
1956	3,317	0	39	S3	85	-	4.30	-	366
1957	1,730	0	39	S3	44	-	4.53	-	201
1958	4,222	0	39	S3	108	-	4.78	-	517
1959	11,640	0	39	S3	298	-	5.03	-	1,502
1960	36,436	0	39	S3	934	-	5.30	-	4,948
1961	2,350	0	39	S3	60	-	5.57	-	336
1962	143	0	39	S3	4	-	5.86	-	21
1963	1,590	0	39	S3	41	-	6.16	-	251
1964	2,469	0	39	S3	63	-	6.48	-	410
1965	11,196	0	39	S3	287	-	6.81	-	1,955
1966	12,600	0	39	S3	323	-	7.16	-	2,313
1967	6,054	0	39	S3	155	-	7.52	-	1,168
1968	5,943	0	39	S3	152	-	7.91	-	1,205
1969	18,946	0	39	S3	486	-	8.31	-	4,036
1970	4,457	0	39	S3	114	-	8.73	-	998
1971	22,690	0	39	S3	582	-	9.17	-	5,337
1972	1,848	0	39	S3	47	-	9.64	-	457
1973	11,003	0	39	S3	282	-	10.13	-	2,858
1974	21,450	0	39	S3	550	-	10.65	-	5,856
1975	68,977	0	39	S3	1,769	-	11.19	-	19,788
1976	25,972	0	39	S3	666	-	11.76	-	7,829
1977	5,860	0	39	S3	150	-	12.35	-	1,856

Delta Natur ıs Company
Depreciatıon Study
As of December 31, 2006
369 -- Measuring Regulating Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	2,125	0	39	S3	54	-	12.98	-	707
1979	11,949	0	39	S3	306	-	13.63	-	4,177
1980	4,539	0	39	S3	116	-	14.32	-	1,666
1981	2,096	0	39	S3	54	-	15.03	-	808
1982	2,119	0	39	S3	54	-	15.77	-	857
1983	11,231	0	39	S3	288	-	16.55	-	4,765
1984	93,670	0	39	S3	2,402	-	17.35	-	41,663
1985	40,669	0	39	S3	1,043	-	18.17	-	18,952
1986	4,156	0	39	S3	107	-	19.03	-	2,028
1987	1,551	0	39	S3	40	-	19.90	-	792
1988	14,728	0	39	S3	378	-	20.80	-	7,856
1989	65,410	23055	39	S3	1,677	591	21.72	-	36,432
1990	40,717	0	39	S3	1,044	-	22.66	-	23,656
1991	39,795	0	39	S3	1,020	-	23.61	-	24,091
1992	43,190	0	39	S3	1,107	-	24.57	-	27,213
1993	44,138	0	39	S3	1,132	-	25.55	-	28,913
1994	37,008	0	39	S3	949	-	26.53	-	25,174
1995	11,055	0	39	S3	283	-	27.52	-	7,800
1996	19,636	0	39	S3	503	-	28.51	-	14,354
1997	138,952	0	39	S3	3,563	-	29.50	-	105,122
1998	198,341	0	39	S3	5,086	-	30.50	-	155,124
1999	363,028	163168	39	S3	9,308	4,184	31.50	-	293,224
2000	185,729	0	39	S3	4,762	-	32.50	-	154,776
2001	84,508	0	39	S3	2,167	-	33.50	-	72,590
2002	184,938	0	39	S3	4,742	-	34.50	-	163,599
2003	78,872	0	39	S3	2,022	-	35.50	-	71,794
2004	146,005	0	39	S3	3,744	-	36.50	-	136,646
2005	249,689	0	39	S3	6,402	-	37.50	-	240,086
2006	219,987	0	39	S3	5,641	-	38.50	-	217,166
	2,624,149	186,223			67,286	4,775	28.93		1,946,582
					Average Remaining Life				27

Survivor Curve	S3
ASL	39

Delta Natura as Company
Depreciation Study
As of December 31, 2006
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	34	L3	-	-	2.89	-	-
1941	-	0	34	L3	-	-	3.09	-	-
1942	-	0	34	L3	-	-	3.30	-	-
1943	-	0	34	L3	-	-	3.51	-	-
1944	-	0	34	L3	-	-	3.72	-	-
1945	-	0	34	L3	-	-	3.93	-	-
1946	-	0	34	L3	-	-	4.15	-	-
1947	-	0	34	L3	-	-	4.37	-	-
1948	-	0	34	L3	-	-	4.59	-	-
1949	-	0	34	L3	-	-	4.82	-	-
1950	-	0	34	L3	-	-	5.05	-	-
1951	400	0	34	L3	12	-	5.29	-	62
1952	-	0	34	L3	-	-	5.53	-	-
1953	-	0	34	L3	-	-	5.77	-	-
1954	-	0	34	L3	-	-	6.02	-	-
1955	1,480	0	34	L3	44	-	6.27	-	273
1956	3,602	0	34	L3	106	-	6.52	-	691
1957	814	0	34	L3	24	-	6.77	-	162
1958	199	0	34	L3	6	-	7.03	-	41
1959	500	0	34	L3	15	-	7.29	-	107
1960	488	0	34	L3	14	-	7.55	-	108
1961	1,719	0	34	L3	51	-	7.81	-	395
1962	-	0	34	L3	-	-	8.07	-	-
1963	-	0	34	L3	-	-	8.32	-	-
1964	264	0	34	L3	8	-	8.56	-	66
1965	-	0	34	L3	-	-	8.80	-	-
1966	4,386	0	34	L3	129	-	9.02	-	1,164
1967	2,857	0	34	L3	84	-	9.23	-	776
1968	798	0	34	L3	23	-	9.43	-	221
1969	64	0	34	L3	2	-	9.62	-	18
1970	19,796	0	34	L3	582	-	9.80	-	5,704
1971	1,439	0	34	L3	42	-	9.97	-	422

Delta Natur as Company
Depreciation Study
As of December 31, 2006
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1972	366	0	34	L3	11	-	10.13	-	109
1973	-	0	34	L3	-	-	10.30	-	-
1974	298	0	34	L3	9	-	10.47	-	92
1975	414	0	34	L3	12	-	10.66	-	130
1976	4,664	0	34	L3	137	-	10.87	-	1,491
1977	16,625	0	34	L3	489	-	11.11	-	5,431
1978	-	0	34	L3	-	-	11.38	-	-
1979	2,354	0	34	L3	69	-	11.69	-	809
1980	572	0	34	L3	17	-	12.04	-	203
1981	1,270	0	34	L3	37	-	12.44	-	465
1982	-	0	34	L3	-	-	12.89	-	-
1983	734	0	34	L3	22	-	13.40	-	289
1984	-	0	34	L3	-	-	13.96	-	-
1985	9,863	0	34	L3	290	-	14.57	-	4,226
1986	6,484	0	34	L3	191	-	15.23	-	2,905
1987	-	0	34	L3	-	-	15.94	-	-
1988	5,063	0	34	L3	149	-	16.69	-	2,486
1989	2,806	0	34	L3	83	-	17.48	-	1,443
1990	779	0	34	L3	23	-	18.30	-	419
1991	-	0	34	L3	-	-	19.15	-	-
1992	7,442	0	34	L3	219	-	20.02	-	4,381
1993	3,144	0	34	L3	92	-	20.90	-	1,933
1994	-	0	34	L3	-	-	21.81	-	-
1995	12,893	0	34	L3	379	-	22.73	-	8,618
1996	3,942	0	34	L3	116	-	23.66	-	2,743
1997	4,101	0	34	L3	121	-	24.61	-	2,968
1998	2,265	0	34	L3	67	-	25.57	-	1,703
1999	3,538	0	34	L3	104	-	26.54	-	2,761
2000	-	0	34	L3	-	-	27.52	-	-
2001	5,172	0	34	L3	152	-	28.51	-	4,336
2002	2,756	0	34	L3	81	-	29.50	-	2,391
2003	2,624	0	34	L3	77	-	30.50	-	2,354
2004	2,883	0	34	L3	85	-	31.50	-	2,671

Delta Naturɛ ɹs Company
Depreciation Study
As of December 31, 2006
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2005	1,850	0	34	L3	54	-	32.50	-	1,768
2006	-	0	34	L3	-	-	33.50	-	-
	143,708	-			4,227	-	16.40		69,337
					Average Remaining Life				16.40

Survivor Curve	L3
ASL	34

Delta Natur.   .s Company
Depreciation Study
As of December 31, 2006
376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	58,962	0	34	R4	1,734	-	-	-	-
1941	-	0	34	R4	-	-	-	-	-
1942	-	0	34	R4	-	-	-	-	-
1943	-	0	34	R4	-	-	-	-	-
1944	-	0	34	R4	-	-	-	-	-
1945	-	0	34	R4	-	-	-	-	-
1946	-	0	34	R4	-	-	-	-	-
1947	75,766	0	34	R4	2,228	-	-	-	-
1948	67,865	0	34	R4	1,996	-	-	-	-
1949	62,008	0	34	R4	1,824	-	-	-	-
1950	29,854	0	34	R4	878	-	-	-	-
1951	36,626	0	34	R4	1,077	-	-	-	-
1952	18,609	0	34	R4	547	-	-	-	-
1953	12,981	0	34	R4	382	-	-	-	-
1954	47,353	0	34	R4	1,393	-	0.50	-	696
1955	148,499	0	34	R4	4,368	-	0.50	-	2,184
1956	143,937	0	34	R4	4,233	-	1.88	-	7,948
1957	39,727	0	34	R4	1,168	-	(0.96)	-	(1,120)
1958	34,326	0	34	R4	1,010	-	0.43	-	431
1959	106,509	0	34	R4	3,133	-	0.82	-	2,573
1960	69,660	0	34	R4	2,049	-	1.11	-	2,267
1961	110,606	0	34	R4	3,253	-	1.37	-	4,452
1962	71,538	0	34	R4	2,104	-	1.63	-	3,424
1963	86,884	0	34	R4	2,555	-	1.89	-	4,826
1964	89,514	0	34	R4	2,633	-	2.15	-	5,668
1965	123,728	0	34	R4	3,639	-	2.42	-	8,814
1966	135,264	0	34	R4	3,978	-	2.70	-	10,732
1967	317,430	0	34	R4	9,336	-	2.98	-	27,852
1968	182,038	0	34	R4	5,354	-	3.28	-	17,580
1969	582,335	0	34	R4	17,128	-	3.60	-	61,731
1970	1,455,571	0	34	R4	42,811	-	3.95	-	169,166
1971	1,074,050	0	34	R4	31,590	-	4.33	-	136,844
1972	324,850	0	34	R4	9,554	-	4.75	-	45,400
1973	448,840	0	34	R4	13,201	-	5.22	-	68,859
1974	294,232	0	34	R4	8,654	-	5.73	-	49,572
1975	409,344	0	34	R4	12,040	-	6.29	-	75,709
1976	201,118	0	34	R4	5,915	-	6.89	-	40,772
1977	215,318	0	34	R4	6,333	-	7.53	-	47,709
1978	316,671	0	34	R4	9,314	-	8.20	-	76,392

Delta Natu as Company
Depreciation Study
As of December 31, 2006
376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	723,822	0	34	R4	21,289	-	8.89	-	189,289
1980	646,465	0	34	R4	19,014	-	9.60	-	182,551
1981	1,960,024	0	34	R4	57,648	-	10.33	-	595,613
1982	1,666,448	0	34	R4	49,013	-	11.08	-	543,304
1983	1,579,871	0	34	R4	46,467	-	11.86	-	551,100
1984	1,436,971	0	34	R4	42,264	-	12.66	-	534,953
1985	1,581,605	0	34	R4	46,518	-	13.48	-	626,898
1986	1,840,623	0	34	R4	54,136	-	14.32	-	775,034
1987	1,938,634	0	34	R4	57,019	-	15.18	-	865,327
1988	2,392,247	0	34	R4	70,360	-	16.05	-	1,129,602
1989	2,519,548	0	34	R4	74,104	-	16.95	-	1,256,077
1990	2,464,496	0	34	R4	72,485	-	17.86	-	1,294,684
1991	3,124,355	0	34	R4	91,893	-	18.79	-	1,726,368
1992	2,153,634	0	34	R4	63,342	-	19.72	-	1,249,407
1993	2,518,971	0	34	R4	74,087	-	20.67	-	1,531,663
1994	2,398,105	0	34	R4	70,533	-	21.63	-	1,525,780
1995	3,191,099	0	34	R4	93,856	-	22.60	-	2,121,050
1996	2,627,094	0	34	R4	77,267	-	23.57	-	1,821,397
1997	2,772,515	1000	34	R4	81,545	29	24.55	4.33	2,002,204
1998	4,460,035	0	34	R4	131,178	-	25.54	-	3,349,739
1999	3,295,415	0	34	R4	96,924	-	26.52	-	2,570,782
2000	3,191,898	0	34	R4	93,879	-	27.51	-	2,583,041
2001	1,634,379	6556	34	R4	48,070	193	28.51	26.52	1,375,474
2002	1,118,713	0	34	R4	32,903	-	29.50	-	970,732
2003	1,493,803	0	34	R4	43,935	-	30.50	-	1,339,980
2004	1,866,444	0	34	R4	54,895	-	31.50	-	1,728,999
2005	1,634,459	0	34	R4	48,072	-	32.49	-	1,562,079
2006	1,344,632	0	34	R4	39,548	-	33.49	-	1,324,581
	66,968,318	7,556			1,969,656	222	19.39		38,198,190

Average Remaining Life 19.4

Survivor Curve	R4
ASL	34

Delta Natu as Company
Depreciation Study
As of December 31, 2006
378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	110	0	36	R1	3	-	1.98	-	6
1941	-	0	36	R1	-	-	2.29	-	-
1942	-	0	36	R1	-	-	2.59	-	-
1943	-	0	36	R1	-	-	2.88	-	-
1944	-	0	36	R1	-	-	3.18	-	-
1945	-	0	36	R1	-	-	3.47	-	-
1946	-	0	36	R1	-	-	3.77	-	-
1947	-	0	36	R1	-	-	4.08	-	-
1948	260	0	36	R1	7	-	4.39	-	32
1949	97	0	36	R1	3	-	4.70	-	13
1950	202	0	36	R1	6	-	5.02	-	28
1951	535	0	36	R1	15	-	5.35	-	80
1952	904	0	36	R1	25	-	5.69	-	143
1953	789	0	36	R1	22	-	6.03	-	132
1954	38	0	36	R1	1	-	6.37	-	7
1955	5,199	0	36	R1	144	-	6.73	-	972
1956	3,855	0	36	R1	107	-	7.09	-	759
1957	1,094	0	36	R1	30	-	7.46	-	227
1958	-	0	36	R1	-	-	7.84	-	-
1959	12,372	0	36	R1	344	-	8.22	-	2,825
1960	-	0	36	R1	-	-	8.61	-	-
1961	-	0	36	R1	-	-	9.01	-	-
1962	321	0	36	R1	9	-	9.42	-	84
1963	-	0	36	R1	-	-	9.83	-	-
1964	608	0	36	R1	17	-	10.26	-	173
1965	881	0	36	R1	24	-	10.69	-	262
1966	5,272	0	36	R1	146	-	11.13	-	1,630
1967	-	0	36	R1	-	-	11.58	-	-
1968	317	0	36	R1	9	-	12.04	-	106
1969	281	0	36	R1	8	-	12.51	-	98
1970	23,330	0	36	R1	648	-	12.98	-	8,413
1971	24,948	0	36	R1	693	-	13.47	-	9,333
1972	13,981	0	36	R1	388	-	13.96	-	5,423
1973	3,975	0	36	R1	110	-	14.47	-	1,598
1974	5,207	0	36	R1	145	-	14.98	-	2,167
1975	6,244	0	36	R1	173	-	15.51	-	2,690
1976	3,610	0	36	R1	100	-	16.04	-	1,609
1977	8,552	0	36	R1	238	-	16.58	-	3,940
1978	7,190	0	36	R1	200	-	17.14	-	3,423

Delta Naturə s Company
Depreciation Study
As of December 31, 2006
378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	9,000	0	36	R1	250	-	17.70	-	4,425
1980	41,132	0	36	R1	1,143	-	18.27	-	20,879
1981	51,901	0	36	R1	1,442	-	18.86	-	27,184
1982	13,595	0	36	R1	378	-	19.45	-	7,344
1983	20,919	0	36	R1	581	-	20.05	-	11,649
1984	16,759	0	36	R1	466	-	20.66	-	9,616
1985	12,417	0	36	R1	345	-	21.27	-	7,338
1986	37,728	0	36	R1	1,048	-	21.90	-	22,951
1987	54,661	0	36	R1	1,518	-	22.53	-	34,214
1988	57,764	0	36	R1	1,605	-	23.17	-	37,185
1989	87,102	0	36	R1	2,420	-	23.82	-	57,638
1990	51,068	0	36	R1	1,419	-	24.48	-	34,722
1991	44,062	0	36	R1	1,224	-	25.14	-	30,767
1992	52,625	0	36	R1	1,462	-	25.80	-	37,720
1993	49,956	0	36	R1	1,388	-	26.47	-	36,738
1994	44,296	0	36	R1	1,230	-	27.15	-	33,408
1995	101,062	0	36	R1	2,807	-	27.83	-	78,130
1996	58,206	0	36	R1	1,617	-	28.52	-	46,105
1997	116,218	0	36	R1	3,228	-	29.20	-	94,280
1998	62,585	0	36	R1	1,738	-	29.90	-	51,976
1999	133,573	0	36	R1	3,710	-	30.60	-	113,519
2000	8,746	0	36	R1	243	-	31.30	-	7,604
2001	27,018	0	36	R1	751	-	32.01	-	24,020
2002	14,796	0	36	R1	411	-	32.72	-	13,447
2003	132,610	0	36	R1	3,684	-	33.44	-	123,170
2004	59,940	0	36	R1	1,665	-	34.16	-	56,880
2005	117,525	0	36	R1	3,265	-	34.89	-	113,911
2006	21,873	0	36	R1	608	-	35.63	-	21,648
	1,629,309	-			45,259	-	26.62		1,204,637

Average Remaining Life 26.6

Survivor Curve	R1
ASL	36

Delta Natura   s Company
Depreciation Study
As of December 31, 2006
379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	37	R2	-	-	0.67	-	-
1941	-	0	37	R2	-	-	0.90	-	-
1942	-	0	37	R2	-	-	1.15	-	-
1943	-	0	37	R2	-	-	1.40	-	-
1944	-	0	37	R2	-	-	1.67	-	-
1945	-	0	37	R2	-	-	1.94	-	-
1946	-	0	37	R2	-	-	2.22	-	-
1947	-	0	37	R2	-	-	2.51	-	-
1948	-	0	37	R2	-	-	2.79	-	-
1949	-	0	37	R2	-	-	3.08	-	-
1950	626	0	37	R2	17	-	3.37	-	57
1951	498	0	37	R2	13	-	3.66	-	49
1952	-	0	37	R2	-	-	3.95	-	-
1953	-	0	37	R2	-	-	4.24	-	-
1954	424	0	37	R2	11	-	4.53	-	52
1955	4,368	0	37	R2	118	-	4.83	-	570
1956	6,252	0	37	R2	169	-	5.13	-	867
1957	2,928	0	37	R2	79	-	5.44	-	430
1958	415	0	37	R2	11	-	5.75	-	65
1959	1,136	0	37	R2	31	-	6.08	-	187
1960	5,188	0	37	R2	140	-	6.41	-	899
1961	729	0	37	R2	20	-	6.75	-	133
1962	103	0	37	R2	3	-	7.11	-	20
1963	-	0	37	R2	-	-	7.48	-	-
1964	118	0	37	R2	3	-	7.86	-	25
1965	185	0	37	R2	5	-	8.26	-	41
1966	10,334	0	37	R2	279	-	8.67	-	2,422
1967	1,607	0	37	R2	43	-	9.10	-	395
1968	13	0	37	R2	0	-	9.54	-	3
1969	1,756	0	37	R2	47	-	10.00	-	475
1970	6,102	0	37	R2	165	-	10.48	-	1,728

Delta Natur as Company
Depreciation Study
As of December 31, 2006
379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1971	-	0	37	R2	-	-	10.97	-	-
1972	-	0	37	R2	-	-	11.48	-	-
1973	-	0	37	R2	-	-	12.00	-	-
1974	1,289	0	37	R2	35	-	12.54	-	437
1975	-	0	37	R2	-	-	13.10	-	-
1976	1,180	0	37	R2	32	-	13.67	-	436
1977	9,218	0	37	R2	249	-	14.25	-	3,551
1978	1,634	0	37	R2	44	-	14.86	-	656
1979	32,008	0	37	R2	865	-	15.47	-	13,385
1980	43,580	0	37	R2	1,178	-	16.10	-	18,966
1981	10,544	0	37	R2	285	-	16.75	-	4,773
1982	-	0	37	R2	-	-	17.41	-	-
1983	14,039	0	37	R2	379	-	18.08	-	6,859
1984	13,765	0	37	R2	372	-	18.76	-	6,980
1985	69,107	0	37	R2	1,868	-	19.46	-	36,349
1986	29,155	0	37	R2	788	-	20.17	-	15,894
1987	41,206	0	37	R2	1,114	-	20.89	-	23,269
1988	-	0	37	R2	-	-	21.63	-	-
1989	-	0	37	R2	-	-	22.37	-	-
1990	-	0	37	R2	-	-	23.13	-	-
1991	33,855	0	37	R2	915	-	23.90	-	21,867
1992	8,924	0	37	R2	241	-	24.68	-	5,952
1993	19,002	0	37	R2	514	-	25.47	-	13,079
1994	37,494	0	37	R2	1,013	-	26.27	-	26,616
1995	13,865	0	37	R2	375	-	27.07	-	10,146
1996	-	0	37	R2	-	-	27.89	-	-
1997	2,853	0	37	R2	77	-	28.72	-	2,215
1998	-	0	37	R2	-	-	29.56	-	-
1999	14,844	0	37	R2	401	-	30.40	-	12,197
2000	-	0	37	R2	-	-	31.26	-	-
2001	-	0	37	R2	-	-	32.12	-	-
2002	13,763	0	37	R2	372	-	32.99	-	12,272

Delta Naturɛ ɑs Company
Depreciation Study
As of December 31, 2006
379 -- Measuring Regulating Station Equipment -- City Gate

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2003	-	0	37	R2	-	-	33.87	-	-
2004	79,594	0	37	R2	2,151	-	34.75	-	74,764
2005	19,922	0	37	R2	538	-	35.65	-	19,194
2006	17,058	0	37	R2	461	-	36.55	-	16,849
	570,681	-			15,424	-	23.02		355,125
				Average Remaining Life					23.0

Survivor Curve	R2
ASL	37

Delta Natur s Company
Depreciation Study
As of December 31, 2006
381 -- Meters

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	1,300	0	40	S1	33	-	3.73	-	121
1941	-	0	40	S1	-	-	4.03	-	-
1942	-	0	40	S1	-	-	4.32	-	-
1943	-	0	40	S1	-	-	4.62	-	-
1944	-	0	40	S1	-	-	4.92	-	-
1945	-	0	40	S1	-	-	5.23	-	-
1946	-	0	40	S1	-	-	5.53	-	-
1947	1,361	0	40	S1	34	-	5.85	-	199
1948	7,200	0	40	S1	180	-	6.16	-	1,109
1949	12,983	0	40	S1	325	-	6.48	-	2,104
1950	11,515	0	40	S1	288	-	6.80	-	1,959
1951	8,282	0	40	S1	207	-	7.13	-	1,477
1952	25,195	0	40	S1	630	-	7.46	-	4,701
1953	4,329	0	40	S1	108	-	7.80	-	844
1954	6,163	0	40	S1	154	-	8.14	-	1,254
1955	14,171	0	40	S1	354	-	8.48	-	3,005
1956	29,813	0	40	S1	745	-	8.83	-	6,583
1957	15,293	0	40	S1	382	-	9.19	-	3,512
1958	17,188	0	40	S1	430	-	9.55	-	4,102
1959	19,856	0	40	S1	496	-	9.91	-	4,920
1960	21,145	0	40	S1	529	-	10.28	-	5,436
1961	24,843	0	40	S1	621	-	10.66	-	6,620
1962	14,485	0	40	S1	362	-	11.04	-	3,998
1963	31,894	0	40	S1	797	-	11.43	-	9,114
1964	18,103	0	40	S1	453	-	11.83	-	5,352
1965	23,944	0	40	S1	599	-	12.23	-	7,320
1966	20,427	0	40	S1	511	-	12.64	-	6,454
1967	36,960	0	40	S1	924	-	13.05	-	12,063
1968	44,180	0	40	S1	1,105	-	13.48	-	14,888
1969	61,872	0	40	S1	1,547	-	13.91	-	21,519
1970	219,572	0	40	S1	5,489	-	14.35	-	78,786
1971	210,607	0	40	S1	5,265	-	14.80	-	77,937
1972	91,736	0	40	S1	2,293	-	15.26	-	34,999
1973	91,823	0	40	S1	2,296	-	15.73	-	36,107
1974	58,878	0	40	S1	1,472	-	16.21	-	23,856
1975	78,982	0	40	S1	1,975	-	16.70	-	32,966
1976	48,111	0	40	S1	1,203	-	17.19	-	20,681
1977	66,317	0	40	S1	1,658	-	17.70	-	29,352

Delta Natu as Company
Depreciation Study
As of December 31, 2006
381 -- Meters

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	67,406	0	40	S1	1,685	-	18.23	-	30,713
1979	53,560	0	40	S1	1,339	-	18.76	-	25,119
1980	69,898	0	40	S1	1,747	-	19.31	-	33,736
1981	92,069	0	40	S1	2,302	-	19.87	-	45,725
1982	195,244	0	40	S1	4,881	-	20.44	-	99,763
1983	125,587	0	40	S1	3,140	-	21.03	-	66,015
1984	147,259	0	40	S1	3,681	-	21.63	-	79,623
1985	82,296	0	40	S1	2,057	-	22.25	-	45,768
1986	81,339	0	40	S1	2,033	-	22.88	-	46,524
1987	125,529	0	40	S1	3,138	-	23.53	-	73,839
1988	216,913	0	40	S1	5,423	-	24.20	-	131,210
1989	86,154	0	40	S1	2,154	-	24.88	-	53,589
1990	195,258	0	40	S1	4,881	-	25.58	-	124,885
1991	142,091	0	40	S1	3,552	-	26.31	-	93,444
1992	105,207	6585	40	S1	2,630	165	27.05	-	71,137
1993	281,873	0	40	S1	7,047	-	27.81	-	195,953
1994	239,405	0	40	S1	5,985	-	28.59	-	171,106
1995	297,778	0	40	S1	7,444	-	29.39	-	218,794
1996	1,004,419	0	40	S1	25,110	-	30.21	-	758,659
1997	94,368	0	40	S1	2,359	-	31.06	-	73,268
1998	828,908	0	40	S1	20,723	-	31.92	-	661,489
1999	221,392	0	40	S1	5,535	-	32.81	-	181,576
2000	203,319	0	40	S1	5,083	-	33.71	-	171,356
2001	408,435	0	40	S1	10,211	-	34.64	-	353,673
2002	577,827	0	40	S1	14,446	-	35.58	-	513,985
2003	1,828,445	0	40	S1	45,711	-	36.54	-	1,670,332
2004	92,829	0	40	S1	2,321	-	37.52	-	87,065
2005	215,473	0	40	S1	5,387	-	38.50	-	207,414
2006	225,642	0	40	S1	5,641	-	39.50	-	222,823
	9,644,451	6,585			241,111	165	28.92		6,971,922
					Average Remaining Life				28.9

Survivor Curve	S1
ASL	40

Delta Natu is Company
Depreciation Study
As of December 31, 2006
382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	386	0	40	S1	10	-	3.73	-	36
1941	-	0	40	S1	-	-	4.03	-	-
1942	-	0	40	S1	-	-	4.32	-	-
1943	-	0	40	S1	-	-	4.62	-	-
1944	-	0	40	S1	-	-	4.92	-	-
1945	-	0	40	S1	-	-	5.23	-	-
1946	-	0	40	S1	-	-	5.53	-	-
1947	291	0	40	S1	7	-	5.85	-	43
1948	543	0	40	S1	14	-	6.16	-	84
1949	1,057	0	40	S1	26	-	6.48	-	171
1950	1,120	0	40	S1	28	-	6.80	-	191
1951	1,784	0	40	S1	45	-	7.13	-	318
1952	293	0	40	S1	7	-	7.46	-	55
1953	394	0	40	S1	10	-	7.80	-	77
1954	1,666	0	40	S1	42	-	8.14	-	339
1955	2,929	0	40	S1	73	-	8.48	-	621
1956	8,754	0	40	S1	219	-	8.83	-	1,933
1957	8,202	0	40	S1	205	-	9.19	-	1,884
1958	6,222	0	40	S1	156	-	9.55	-	1,485
1959	4,846	0	40	S1	121	-	9.91	-	1,201
1960	3,986	0	40	S1	100	-	10.28	-	1,025
1961	3,306	0	40	S1	83	-	10.66	-	881
1962	9,394	0	40	S1	235	-	11.04	-	2,593
1963	1,800	0	40	S1	45	-	11.43	-	514
1964	1,800	0	40	S1	45	-	11.83	-	532
1965	2,280	0	40	S1	57	-	12.23	-	697
1966	2,088	0	40	S1	52	-	12.64	-	660
1967	4,152	0	40	S1	104	-	13.05	-	1,355
1968	5,823	0	40	S1	146	-	13.48	-	1,962
1969	8,651	0	40	S1	216	-	13.91	-	3,009
1970	8,413	0	40	S1	210	-	14.35	-	3,019
1971	6,017	0	40	S1	150	-	14.80	-	2,227
1972	6,795	0	40	S1	170	-	15.26	-	2,592
1973	8,877	0	40	S1	222	-	15.73	-	3,491
1974	5,641	0	40	S1	141	-	16.21	-	2,286
1975	4,065	0	40	S1	102	-	16.70	-	1,697
1976	2,843	0	40	S1	71	-	17.19	-	1,222
1977	2,209	0	40	S1	55	-	17.70	-	978

Delta Naturɛ ɜ Company
Depreciatıon Study
As of December 31, 2006
382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	1,604	0	40	S1	40	-	18.23	-	731
1979	4,463	0	40	S1	112	-	18.76	-	2,093
1980	5,200	0	40	S1	130	-	19.31	-	2,510
1981	12,046	0	40	S1	301	-	19.87	-	5,983
1982	66,540	0	40	S1	1,664	-	20.44	-	34,000
1983	99,610	0	40	S1	2,490	-	21.03	-	52,360
1984	94,296	0	40	S1	2,357	-	21.63	-	50,986
1985	67,324	0	40	S1	1,683	-	22.25	-	37,442
1986	69,688	0	40	S1	1,742	-	22.88	-	39,860
1987	60,219	0	40	S1	1,505	-	23.53	-	35,422
1988	71,400	0	40	S1	1,785	-	24.20	-	43,190
1989	89,262	296457	40	S1	2,232	7,411	24.88	-	55,522
1990	147,697	0	40	S1	3,692	-	25.58	-	94,465
1991	118,996	0	40	S1	2,975	-	26.31	-	78,256
1992	170,332	0	40	S1	4,258	-	27.05	-	115,172
1993	142,352	0	40	S1	3,559	-	27.81	-	98,961
1994	160,617	0	40	S1	4,015	-	28.59	-	114,795
1995	148,177	0	40	S1	3,704	-	29.39	-	108,874
1996	150,837	0	40	S1	3,771	-	30.21	-	113,930
1997	149,850	0	40	S1	3,746	-	31.06	-	116,345
1998	172,095	0	40	S1	4,302	-	31.92	-	137,336
1999	155,766	0	40	S1	3,894	-	32.81	-	127,753
2000	122,090	0	40	S1	3,052	-	33.71	-	102,897
2001	98,891	0	40	S1	2,472	-	34.64	-	85,632
2002	93,543	0	40	S1	2,339	-	35.58	-	83,208
2003	102,667	0	40	S1	2,567	-	36.54	-	93,789
2004	112,534	0	40	S1	2,813	-	37.52	-	105,547
2005	110,798	0	40	S1	2,770	-	38.50	-	106,655
2006	82,818	0	40	S1	2,070	-	39.50	-	81,783
	3,008,339	296,457			75,208	7,411	28.78		2,164,668
				Average Remaining Life					26.2

Survivor Curve	S1
ASL	40

Delta Natur   ıs Company
Depreciatıon Study
As of December 31, 2006
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	563	0	28	S6	20	-	-	-	-
1941	-	0	28	S6	-	-	-	-	-
1942	-	0	28	S6	-	-	-	-	-
1943	-	0	28	S6	-	-	-	-	-
1944	-	0	28	S6	-	-	-	-	-
1945	-	0	28	S6	-	-	-	-	-
1946	-	0	28	S6	-	-	-	-	-
1947	6,423	0	28	S6	229	-	-	-	-
1948	560	0	28	S6	20	-	-	-	-
1949	508	0	28	S6	18	-	-	-	-
1950	1,192	0	28	S6	43	-	-	-	-
1951	3,347	0	28	S6	120	-	-	-	-
1952	1,274	0	28	S6	46	-	-	-	-
1953	1,063	0	28	S6	38	-	-	-	-
1954	1,689	0	28	S6	60	-	-	-	-
1955	4,186	0	28	S6	150	-	-	-	-
1956	8,755	0	28	S6	313	-	-	-	-
1957	6,486	0	28	S6	232	-	-	-	-
1958	4,537	0	28	S6	162	-	-	-	-
1959	4,836	0	28	S6	173	-	-	-	-
1960	5,466	0	28	S6	195	-	-	-	-
1961	10,139	0	28	S6	362	-	-	-	-
1962	4,564	0	28	S6	163	-	-	-	-
1963	8,161	0	28	S6	291	-	-	-	-
1964	5,251	0	28	S6	188	-	-	-	-
1965	9,372	0	28	S6	335	-	-	-	-
1966	5,883	0	28	S6	210	-	-	-	-
1967	8,100	0	28	S6	289	-	0.50	-	145
1968	10,199	0	28	S6	364	-	0.50	-	182
1969	15,644	0	28	S6	559	-	0.54	-	303
1970	15,245	0	28	S6	544	-	0.57	-	313
1971	44,148	0	28	S6	1,577	-	0.61	-	968
1972	18,706	0	28	S6	668	-	0.67	-	445
1973	18,408	0	28	S6	657	-	0.73	-	482
1974	29,340	0	28	S6	1,048	-	0.82	-	860
1975	12,375	0	28	S6	442	-	0.94	-	414
1976	18,467	0	28	S6	660	-	1.09	-	717
1977	29,083	0	28	S6	1,039	-	1.29	-	1,337
1978	20,730	0	28	S6	740	-	1.55	-	1,151

Delta Natu.   as Company
Depreciation Study
As of December 31, 2006
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	17,688	0	28	S6	632	-	1.91	-	1,207
1980	44,258	0	28	S6	1,581	-	2.38	-	3,764
1981	46,611	0	28	S6	1,665	-	2.99	-	4,969
1982	62,018	0	28	S6	2,215	-	3.73	-	8,255
1983	79,203	0	28	S6	2,829	-	4.59	-	12,975
1984	68,536	0	28	S6	2,448	-	5.53	-	13,527
1985	82,809	0	28	S6	2,957	-	6.51	-	19,241
1986	45,980	0	28	S6	1,642	-	7.50	-	12,318
1987	107,385	3463	28	S6	3,835	124	8.50	-	32,599
1988	84,581	0	28	S6	3,021	-	9.50	-	28,697
1989	114,666	0	28	S6	4,095	-	10.50	-	43,000
1990	112,102	0	28	S6	4,004	-	11.50	-	46,042
1991	63,398	0	28	S6	2,264	-	12.50	-	28,303
1992	95,099	0	28	S6	3,396	-	13.50	-	45,851
1993	152,812	0	28	S6	5,458	-	14.50	-	79,135
1994	115,494	0	28	S6	4,125	-	15.50	-	63,934
1995	126,610	0	28	S6	4,522	-	16.50	-	74,609
1996	114,577	0	28	S6	4,092	-	17.50	-	71,611
1997	85,933	0	28	S6	3,069	-	18.50	-	56,777
1998	340,732	295	28	S6	12,169	11	19.50	9.50	237,396
1999	161,756	0	28	S6	5,777	-	20.50	-	118,429
2000	136,617	0	28	S6	4,879	-	21.50	-	104,902
2001	84,144	0	28	S6	3,005	-	22.50	-	67,616
2002	114,466	0	28	S6	4,088	-	23.50	-	96,070
2003	108,820	0	28	S6	3,886	-	24.50	-	95,218
2004	115,491	0	28	S6	4,125	-	25.50	-	105,179
2005	142,384	0	28	S6	5,085	-	26.50	-	134,756
2006	181,209	0	28	S6	6,472	-	27.50	-	177,973
	3,340,079	3,758			119,289	134	15.02		1,791,668
					Average Remaining Life				15.0

Survivor Curve	S6
ASL	28

Delta Natu as Company
Depreciation Study
As of December 31, 2006
385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	43	R1	-	-	6.32	-	-
1941	-	0	43	R1	-	-	6.65	-	-
1942	-	0	43	R1	-	-	6.99	-	-
1943	-	0	43	R1	-	-	7.33	-	-
1944	-	0	43	R1	-	-	7.68	-	-
1945	-	0	43	R1	-	-	8.04	-	-
1946	-	0	43	R1	-	-	8.40	-	-
1947	-	0	43	R1	-	-	8.77	-	-
1948	-	0	43	R1	-	-	9.14	-	-
1949	-	0	43	R1	-	-	9.52	-	-
1950	-	0	43	R1	-	-	9.91	-	-
1951	-	0	43	R1	-	-	10.30	-	-
1952	-	0	43	R1	-	-	10.70	-	-
1953	-	0	43	R1	-	-	11.11	-	-
1954	-	0	43	R1	-	-	11.52	-	-
1955	-	0	43	R1	-	-	11.94	-	-
1956	702	0	43	R1	16	-	12.36	-	202
1957	1,860	0	43	R1	43	-	12.80	-	554
1958	1,172	0	43	R1	27	-	13.24	-	361
1959	366	0	43	R1	9	-	13.69	-	116
1960	1,596	0	43	R1	37	-	14.14	-	525
1961	941	0	43	R1	22	-	14.60	-	320
1962	168	0	43	R1	4	-	15.07	-	59
1963	1,767	0	43	R1	41	-	15.55	-	639
1964	308	0	43	R1	7	-	16.04	-	115
1965	1,098	0	43	R1	26	-	16.53	-	422
1966	1,847	0	43	R1	43	-	17.03	-	732
1967	2,885	0	43	R1	67	-	17.54	-	1,177
1968	2,179	0	43	R1	51	-	18.06	-	915
1969	1,759	0	43	R1	41	-	18.59	-	760
1970	3,485	0	43	R1	81	-	19.12	-	1,550
1971	3,084	0	43	R1	72	-	19.66	-	1,410
1972	2,554	0	43	R1	59	-	20.21	-	1,201
1973	3,174	0	43	R1	74	-	20.77	-	1,533
1974	2,543	0	43	R1	59	-	21.34	-	1,262
1975	1,682	0	43	R1	39	-	21.91	-	857
1976	6,518	0	43	R1	152	-	22.50	-	3,410
1977	-	0	43	R1	-	-	23.09	-	-
1978	4,035	0	43	R1	94	-	23.69	-	2,223
1979	3,969	0	43	R1	92	-	24.29	-	2,242

Delta Natur s Company
Depreciation Study
As of December 31, 2006
385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	4,307	0	43	R1	100	-	24.90	-	2,494
1981	33,109	0	43	R1	770	-	25.52	-	19,652
1982	19,688	0	43	R1	458	-	26.15	-	11,973
1983	17,371	0	43	R1	404	-	26.78	-	10,819
1984	26,528	0	43	R1	617	-	27.42	-	16,917
1985	39,740	0	43	R1	924	-	28.07	-	25,938
1986	70,515	0	43	R1	1,640	-	28.72	-	47,092
1987	58,538	0	43	R1	1,361	-	29.37	-	39,987
1988	109,462	0	43	R1	2,546	-	30.03	-	76,456
1989	141,310	0	43	R1	3,286	-	30.70	-	100,888
1990	98,320	0	43	R1	2,287	-	31.37	-	71,728
1991	71,191	0	43	R1	1,656	-	32.04	-	53,053
1992	42,672	0	43	R1	992	-	32.72	-	32,473
1993	79,131	0	43	R1	1,840	-	33.40	-	61,471
1994	89,330	0	43	R1	2,077	-	34.09	-	70,817
1995	89,881	0	43	R1	2,090	-	34.78	-	72,693
1996	72,772	0	43	R1	1,692	-	35.47	-	60,027
1997	57,974	0	43	R1	1,348	-	36.17	-	48,759
1998	91,757	0	43	R1	2,134	-	36.87	-	78,666
1999	60,714	0	43	R1	1,412	-	37.57	-	53,046
2000	54,409	0	43	R1	1,265	-	38.28	-	48,434
2001	70,925	0	43	R1	1,649	-	38.99	-	64,312
2002	13,368	0	43	R1	311	-	39.71	-	12,345
2003	54,587	0	43	R1	1,269	-	40.43	-	51,326
2004	53,260	0	43	R1	1,239	-	41.16	-	50,980
2005	31,213	0	43	R1	726	-	41.89	-	30,409
2006	51,486	0	43	R1	1,197	-	42.63	-	51,043
	1,653,250	-			38,448	-	33.46		1,286,383
					Average Remaining Life				33.5

Survivor Curve	R1
ASL	43

Delta Natur ɩs Company
Depreciatıon Study
As of December 31, 2006
390 -- General Plant Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	32	R3	-	-	-	-	-
1941	-	0	32	R3	-	-	-	-	-
1942	-	0	32	R3	-	-	-	-	-
1943	-	0	32	R3	-	-	-	-	-
1944	-	0	32	R3	-	-	-	-	-
1945	-	0	32	R3	-	-	-	-	-
1946	-	0	32	R3	-	-	-	-	-
1947	-	0	32	R3	-	-	-	-	-
1948	-	0	32	R3	-	-	-	-	-
1949	-	0	32	R3	-	-	-	-	-
1950	-	0	32	R3	-	-	-	-	-
1951	-	0	32	R3	-	-	-	-	-
1952	-	0	32	R3	-	-	0.50	-	-
1953	-	0	32	R3	-	-	0.50	-	-
1954	-	0	32	R3	-	-	0.57	-	-
1955	-	0	32	R3	-	-	0.73	-	-
1956	-	0	32	R3	-	-	0.93	-	-
1957	-	0	32	R3	-	-	1.15	-	-
1958	20,586	0	32	R3	643	-	1.39	-	893
1959	27,726	0	32	R3	866	-	1.63	-	1,415
1960	250	0	32	R3	8	-	1.88	-	15
1961	832	0	32	R3	26	-	2.14	-	56
1962	1,197	0	32	R3	37	-	2.39	-	89
1963	23,367	0	32	R3	730	-	2.65	-	1,932
1964	357	0	32	R3	11	-	2.90	-	32
1965	10,712	0	32	R3	335	-	3.16	-	1,059
1966	24,179	0	32	R3	756	-	3.43	-	2,592
1967	149	0	32	R3	5	-	3.71	-	17
1968	3,179	0	32	R3	99	-	4.00	-	398
1969	94	0	32	R3	3	-	4.31	-	13
1970	37,380	0	32	R3	1,168	-	4.64	-	5,425
1971	29,546	0	32	R3	923	-	5.00	-	4,617
1972	11,406	0	32	R3	356	-	5.38	-	1,919
1973	84,336	0	32	R3	2,636	-	5.79	-	15,267
1974	480	0	32	R3	15	-	6.23	-	93
1975	700	0	32	R3	22	-	6.70	-	147
1976	2,119	0	32	R3	66	-	7.20	-	477
1977	1,374	0	32	R3	43	-	7.73	-	332

Delta Naturₐ s Company
Depreciation Study
As of December 31, 2006
390 -- General Plant Structures and Improvements

1978	568,930	0	32	R3	17,779	-	8.29	-	147,311
1979	23,860	0	32	R3	746	-	8.87	-	6,615
1980	58,518	0	32	R3	1,829	-	9.48	-	17,342
1981	253,709	0	32	R3	7,928	-	10.12	-	80,246
1982	171,370	0	32	R3	5,355	-	10.78	-	57,747
1983	79,384	0	32	R3	2,481	-	11.47	-	28,449
1984	176,763	0	32	R3	5,524	-	12.17	-	67,246
1985	138,267	0	32	R3	4,321	-	12.90	-	55,739
1986	79,344	0	32	R3	2,480	-	13.65	-	33,833
1987	21,786	0	32	R3	681	-	14.41	-	9,810
1988	9,828	0	32	R3	307	-	15.19	-	4,665
1989	158,943	0	32	R3	4,967	-	15.99	-	79,410
1990	247,667	0	32	R3	7,740	-	16.80	-	130,037
1991	910	0	32	R3	28	-	17.63	-	501
1992	26,100	0	32	R3	816	-	18.48	-	15,069
1993	115,754	0	32	R3	3,617	-	19.34	-	69,942
1994	525,596	0	32	R3	16,425	-	20.21	-	331,927
1995	62,193	0	32	R3	1,944	-	21.10	-	41,000
1996	150,022	0	32	R3	4,688	-	21.99	-	103,116
1997	11,853	0	32	R3	370	-	22.91	-	8,485
1998	33,458	0	32	R3	1,046	-	23.83	-	24,914
1999	310,970	0	32	R3	9,718	-	24.76	-	240,627
2000	21,039	0	32	R3	657	-	25.70	-	16,899
2001	41,155	0	32	R3	1,286	-	26.65	-	34,280
2002	1,331,240	0	32	R3	41,601	-	27.61	-	1,148,740
2003	489,667	0	32	R3	15,302	-	28.58	-	437,311
2004	346,841	0	32	R3	10,839	-	29.55	-	320,286
2005	20,333	0	32	R3	635	-	30.53	-	19,397
2006	55,450	0	32	R3	1,733	-	31.51	-	54,598
	5,810,919	-			181,591	-	19.95		3,622,329
				Average Remaining Life					20

Survivor Curve	R3
ASL	32