In the Matter of:

APPICATION OF DELTA	)	
NATURAL GAS COMPANY	)	Case No. 2004-00067
FOR AN ADJUSTMENT OF	)	
RATES	)	

ATTORNEY GENERAL'S DIRECT TESTIMONIES

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

GREGORY D. STUMBO
ATTORNEY GENERAL

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June 30, 2004

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PUBLIC SERVICE
COMMISSION

Ms. Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY. 40601

RE: In the Matter of: Application of Delta Natural Gas Company for an Adjustment of Rates, PSC Case No. 2004-00067.

Dear Ms. O'Donnell:

Please find enclosed the Attorney General's pre-filed testimonies in the above noted case. The witnesses offering pre-filed testimony are: Robert J. Henkes, Michael J. Majoros, Jr., Charles W. King, and David H. Brown Kinloch.

In accordance with the procedural schedule, one original and ten copies of the testimony, together with supporting schedules and exhibits, are being filed today with the Commission. A copy is also being served on all parties of record.

Sincerely,

Dennis G. Howard, II
Acting Director

cc: Parties of record.

Enclosures//

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY FOR AN ADJUSTMENT OF RATES	))	CASE NO. 2004-00067

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

July 2, 2004

Delta Natural Gas Company
Case No. 2004-00067
Direct Testimony of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony in the matter of the petition of Delta Natural Gas Company ("Delta" or the "Company") for an increase in its base rates for gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the appropriate rate base and pro forma test period operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In the determination of the AG's recommended rate base, operating income and revenue requirement, I have relied on and incorporated the recommendations of Mr. Charles W. King, concerning the appropriate return on common equity and overall rate of return on rate base; and Mr. Michael Majoros, concerning the appropriate depreciation rates and associated annualized depreciation expenses to be reflected for Delta in this proceeding.

In developing this testimony, I have reviewed and analyzed the Company's April 5, 2004 filing; supporting testimonies, exhibits, filing requirements and workpapers; the Company's responses to initial and follow-up data requests by the KPSC Staff and the AG; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. I have reached the following findings and conclusions in this case:

1. The appropriate pro forma adjusted rate base measured as of December 31, 2003, the end of the test period in this case, amounts to approximately $111,751,945. This is $680,287 higher than the Company's proposed pro forma test year-end rate base of $111,071,658. See schedule RJH-3

2. The AG's expert rate of return witness, Mr. Charles King, has recommended a return on equity rate of 10.05% and an overall rate of return on rate base of 7.64%. By comparison, the Company has proposed a return on equity rate of 12.50% and an overall rate of return on rate base of approximately 8.55%. See schedule RJH-2.

3. The appropriate pro forma adjusted test period operating income amounts to $7,712,598. This is $806,813 higher than Delta's proposed pro forma adjusted test period operating income of $6,905,785. See schedule RJH-6.

4. The appropriate revenue conversion factor to be used for rate making purposes in this case is 1.6544073. This is higher than the Company's proposed revenue conversion factor of 1.6513912 and has the effect of increasing the Company's revenue requirement. See schedule RJH-1, line 6.

5. The application of the recommended overall rate of return of 7.64% to the recommended rate base of $111,751,945, combined with the recommended pro forma test period operating income of $7,712,598 and the revenue conversion factor of 1.6544073 indicates that the Company has an overall annual revenue deficiency of $1,364,420. This is $2,913,052 lower than the Company's proposed annual revenue deficiency of $4,277,471. See schedule RJH-1, lines 1-7.

IV. REVENUE REQUIREMENT ISSUES

A. RATE BASE

Q. HAVE YOU DETERMINED THE APPROPRIATE ADJUSTED ORIGINAL COST RATE BASE FOR DELTA IN THIS CASE?

A. Yes, this recommended adjusted gas original cost rate base has been developed on schedule RJH-3. The starting point is Delta's proposed rate base measured as of the end of the test year, December 31, 2003. I then made three adjustments in order to arrive at the AG's recommended adjusted original cost rate base to be used for ratemaking purposes in this case. These three recommended rate base adjustments are shown on schedule RJH-3, lines 4, 5 and 11 and will be discussed in detail in the subsequent sections of this testimony.

\- **<u>Cash Working Capital</u>**

Q. PLEASE DESCRIBE THE DERIVATION OF THE COMPANY'S CASH WORKING CAPITAL AMOUNT CLAIMED IN THIS CASE.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "modified 1/8th formula" method. This method assumes that 1/8th of the pro forma test year gas operation and maintenance expenses (net of gas supply expenses) represents a reasonable cash working capital approximation. As shown in the first column of schedule RJH-4, based on this methodology the Company has calculated a proposed cash working capital of approximately $1,290,427.

Q. DO YOU AGREE WITH THE USE OF THE MODIFIED 1/8TH METHOD TO DETERMINE THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT?

A. No. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

Q. WHAT IS THE REASON FOR YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED CASH WORKING CAPITAL, AS SHOWN ON SCHEDULE RJH-4?

A. The recommended cash working capital adjustment is simply an automatic flow-through effect of the AG's recommended adjustments to Delta's proposed test year O&M expenses.

- **Prepayments**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO DELTA'S PROPOSED PREPAYMENTS IN RATE BASE, AS SHOWN ON SCHEDULE RJH-3, LINE 5.

A. As confirmed by Delta in its response to AG-1-5, the proposed prepayment balance in rate base includes $39,440 for alleged prepayments associated with KPSC assessments. This Commission has a long-standing and well-established ratemaking policy to exclude such KPSC assessment prepayments from rate base for the reason that the Commission disagrees with the position that these KPSC assessment balances actually represent prepayments. In accordance with the KPSC ratemaking policy, I have removed these alleged KPSC assessment prepayments from rate base.

- **<u>Accumulated Depreciation Reserve Adjustment</u>**

Q. PLEASE EXPLAIN DELTA'S PROPOSED DEPRECIATION RESERVE ADJUSTMENT SHOWN ON LINE 11 OF SCHEDULE RJH-3.

A. As shown in the first column of schedule RJH-15, the depreciation reserve adjustment represents the annualized impact on rate base of the difference between Delta's proposed pro forma annualized depreciation expenses and the test year per books depreciation expenses. I agree with this type of adjustment.

Q. WHAT IS THE REASON FOR THE DIFFERENCE BETWEEN DELTA'S PROPOSED AND THE AG'S RECOMMENDED DEPRECIATION RESERVE ADJUSTMENT?

A. As shown on schedule RJH-15, this reason is a direct result of the AG's recommended adjustment to the Company's proposed pro forma annualized depreciation expenses in this case.

B. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO YOUR RECOMMENDED PRO FORMA OPERATING INCOME FOR THE TEST PERIOD IN THIS CASE.

A. The Company's proposed and my recommended pro forma test year operating income positions are summarized on schedule RJH-5. The Company has proposed total pro forma test period operating income of $6,905,785. As summarized on schedule RJH-5, I have made a large number of pro forma operating income adjustments which, in total, have the effect of increasing the Company's proposed test year operating income by $806,813 to total recommended pro forma test period operating income of $7,712,598. Each of the recommended operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Net Revenue Adjustment for Test Year-End Customer Growth**

Q. HAS DELTA PROPOSED A PRO FORMA REVENUE ADJUSTMENT TO REFLECT TEST YEAR-END CUSTOMER LEVELS IN ORDER TO MATCH THE USE OF A TEST YEAR-END RATE BASE IN THIS CASE?

A. No. As described on page 23 of his testimony, Company witness Seelye compared the Company's customer levels at the end of the test year, 12/31/03, to the corresponding customer levels at 12/31/02 and found that this comparison produced a reduction in the Company's test year number of customers. Based on this information, Mr. Seelye did not believe that it was appropriate to make a pro forma test year-end customer growth adjustment.

Q. IS THE METHOD USED IN THIS CASE TO MEASURE TEST YEAR CUSTOMER GROWTH CONSISTENT WITH THE METHOD USED BY DELTA IN ITS PRIOR RATE CASE, CASE NO. 99-176?

A. No. In fact, I do not believe that Mr. Seeelye's proposed test year customer growth method in this case has ever previously been used by Delta[1] or adopted by the KPSC. In Delta's prior rate case, Case No. 99-176, the Company measured its test year customer growth by comparing the test year-end customer level to the corresponding average test year customer level. Mr. Walker, the Delta witness sponsoring the Company's customer growth adjustment in Case No. 99-176, stated with regard to this adjustment on page 7 of this testimony:

> The numbers of customers served at the end of the test period were greater than the average of the 12-month period. The purpose of this adjustment is to give recognition to the additional deliveries and revenue that would have been expected assuming that the year-end number of customers has been served for the entire test period.

Q. IS THE CUSTOMER GROWTH METHOD USED BY MR. SEELYE IN THIS CASE CONSISTENT WITH THE CUSTOMER GROWTH METHOD ADVOCATED BY HIM IN THE PENDING LG&E GAS AND ELECTRIC RATE CASES, CASE NO. 2003-00433?

A. No. In these LG&E rate cases, Mr. Seelye strongly argued for the test year-end vs. average

[1] Or, for that matter, by any other Kentucky utility proposing a test year-end customer growth adjustment.

test year customer growth measurement method and argued that any other method would be "inconsistent with the one traditionally used by the Commission."[2] On page 27 of his rebuttal testimony in Case No. 2003-00433, Mr. Seelye states with regard to this issue:

> The same [year-end vs. average number of test year customers] methodology has been used for many years in computing the revenue component of the year-end adjustment. As explained earlier, the theory behind the year-end adjustment is to restate revenues and expenses to reflect the difference between (i) the number of customers served at the end of the test year and (ii) the average number of customers served during the test year as reflected in revenues and expenses. Because rate base and capitalization are valued as of the end of the test year, the Commission determined many years ago that it would be appropriate to make a year-end adjustment to place revenues and expenses on the same footing as year-end rate base. The revenue component of the year-end adjustment is therefore computed by measuring the difference between the number of customers at the end of the test year and the average number of customers during the test year, and then multiplying this difference by rate class to the average normalized revenue per customer.

Q. WHILE MR. SEELYE'S PROPOSED CUSTOMER GROWTH METHOD IN THIS CASE INDICATES AN ALLEGED REDUCTION IN THE NUMBER OF TEST YEAR CUSTOMERS, WHAT ARE THE RESULTS BASED ON THE TEST YEAR-END VERSUS AVERAGE CUSTOMER MEASUREMENT METHOD?

A. As confirmed by Mr. Seelye in his response to AG-1-32, the test year-end versus average number of customer comparison clearly shows that there is customer growth for each of the Company's customer classes:

	12/31/03	13-Mos. Avg.	Growth
Residential	34,100	33,759	341
Small Commercial	4,629	4,491	138
Large Commercial	818	815	3
Industrial	63	62	1

2 Seelye rebuttal testimony, page 27, lines 16-17, LG&E Case No. 2003-00433.

Q. DID YOU REQUEST MR. SEELYE TO PROVIDE A CALCULATION OF THE TEST YEAR-END CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT IN THE SAME FORMAT AND DETAIL AS WAS PROPOSED BY DELTA AND ADOPTED BY THE KPSC IN DELTA'S PRIOR RATE CASE, CASE NO. 99-176?

A. Yes. In data request AG-1-32 e-f, I made the following request to Mr. Seelye with regard to this matter:

> e. In the exact same format and detail as presented on Walker Exhibit 5 in the Company's prior case, please calculate the test year-end customer growth revenue annualization adjustment based on the difference between the 12/31/03 and 13-month average test year customer numbers for the following customer classes: (1) residential, (2) small non-residential GS-retail, (3) large residential GS – transportation, (4) interruptible – retail, (5) interruptible transportation, and (6) on-system transportation special.
>
> f. Provide the expense adjustment associated with the revenue annualization adjustment to be provided in response to part e. The expense adjustment should include the expense components allowed by the Commission in Delta's prior rate case, Case No. 99-176, as described on page 14 of the PSC Order in that case.

Q. DID MR. SEELYE PROVIDE THE REQUESTED INFORMATION?

A. No. Mr. Seelye's response to data request AG-1-32 e-f was as follows:

> e-f Delta has not prepared the requested analysis. The information necessary to perform the requested analysis can be obtained from the exhibits to Mr. Seelye's testimony.

Q. SINCE DELTA HAS REFUSED TO CALCULATE THE TEST YEAR-END CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT IN A

MANNER CONSISTENT WITH THE METHOD USED BY DELTA IN ITS PRIOR CASE -- WHICH METHOD MR. SEELYE HAS CHARACTERIZED AS THE "METHOD TRADITIONALLY USED BY THE COMMISSION"--, HAVE YOU MADE THE CALCULATIONS YOURSELF?

A. Yes. On schedule RJH-6A, I have calculated the net revenue adjustment for test year-end customer growth in a manner consistent with the method proposed by Delta and adopted by the Commission in Case No. 99-176. From the data available to me, I determined that the test year-end versus average customer level comparison showed no change in the test year Interruptible and Transportation customer classes. For that reason, schedule RJH-6A only shows the customer classes where customer growth took place in the test year, i.e., the Residential, and Small and Large Non-Residential GS Retail customer classes. As shown on line 5, and further detailed in footnote (f) of schedule RJH-6A, I also calculated the cost increase associated with the customer growth revenue adjustment. This cost increase is based on an Operating Ratio of 12.40%, which was calculated in accordance with the manner prescribed on page 14 of the Commission's Order in Case No. 99-176.

Q. **WHAT IS THE NET REVENUE ADJUSTMENT FROM TEST YEAR CUSTOMER GROWTH THAT YOU HAVE CALCULATED ON SCHEDULE 6A?**

A. As shown on schedule RJH-6A, lines 4-6, the revenue adjustment amounts to $239,331. This should then be offset by an associated expense adjustment of $29,677, resulting in a test year-end customer growth net revenue adjustment of $209,654. Thus, if the Commission were to decide to continue to use the test year-end versus test year average customer growth measurement method, it should increase the Company's pro forma test year revenues by $239,331 and pro forma test year operating expenses by $29,654. Since this calculation method was the customer growth method most recently adopted by the Commission in Delta's prior case, I have reflected these revenue and expense adjustments on schedule RJH-5, line 1 and schedule RJH-7, line 2 for purposes of presenting the AG's revenue requirement position in this testimony.

Q. HAVE YOU ALSO CALCULATED THE TEST YEAR CUSTOMER GROWTH ADJUSTMENT IN ACCORDANCE WITH THE METHOD USED BY YOU AND ADOPTED BY THE COMMISSION IN DELTA'S 1997 RATE CASE, CASE NO. 97-066?

A. Yes. This customer growth calculation method – which I prefer over the test year-end versus test year average customer growth calculation method – is shown on schedule RJH-6B. As shown on this schedule, this method calculates test year-end customer growth by applying an appropriate half-year compound average growth rate to the test year's average number of customers. Lines 4-6 of schedule RJH-6B indicate that this customer growth methodology produces a revenue adjustment of $98,189 with an offsetting expense adjustment of $12,175, for a net revenue adjustment of $86,014. Thus, if the Commission were to decide that this customer growth methodology is the more preferred method in this case, it should increase the Company's pro forma test year revenues by $98,189 and pro forma test year operating expenses by $12,175.

- **Interest on Customer Deposits**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION WITH REGARD TO CUSTOMER DEPOSITS AND THE ASSOCIATED INTEREST ON CUSTOMER DEPOSITS?

A. The Company has proposed to include customer deposit interest of $33,554 as an "above-the-line" operating expense in this case. While the Company did not treat the associated customer deposit balance of $559,231 as a rate base deduction, in its responses to PSC-2-8 and PSC-3-5, it conceded that if customer deposit interest is included for ratemaking purposes as an operating expense, then it would be appropriate to treat the associated customer deposit balance as a rate base deduction.

Q. IS THIS PROPOSED POSITION IN ACCORDANCE WITH KPSC RATEMAKING POLICY?

A. No. As referenced in Delta's response to PSC-3-5, the KPSC clarified its policy with regard to customer deposits on page 9 of its December 27, 1999 Order in Delta's prior rate case, Case No. 99-176 as follows:

> In Case No. 97-066, the Commission included the interest on customer deposits in Delta's pro forma operating expenses, but did not reduce rate base by the customer deposit balance. We concede that our action was not consistent. The customer deposit balance and interest must both be included or excluded in determining the revenue requirement. Since customer deposits represent a liability to be repaid to the customer with interest, the Commission generally has not recognized the deposits as readily available cost free capital. For this reason, the Commission finds that the AG's proposed adjustment should be denied. We further find that all interest associated with the customer deposits should be excluded from Delta's pro forma operating expenses.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. In accordance with KPSC ratemaking policy, I have removed the customer deposit interest expense of $33,554 from the test year operating expenses. My recommendation is reflected on schedule RJH-7, line 3.

- **<u>Adjustment to Bonus Expense Removal</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO DELTA'S PROPOSED BONUS EXPENSE REMOVAL, AS SHOWN ON SCHEDULE RJH-7, LINE 4.

A. As shown on Hall WP-4.1, in its original filing, Delta had proposed to remove $403,865 for bonus expenses which the Company deemed inappropriate for rate recovery from the ratepayers. However, during the course of this proceeding the Company found that $86,000 of this bonus expense was charged to its subsidiaries and was already separately removed from the test year through Account 1.922 Expenses Transferred.[3] Thus, it is now the Company's position that the bonus expense removal adjustment of $403,865 on Hall WP-4.1 should be reduced by $86,000 to $317,865.[4] Based on my review of this issue, I agree that Delta's proposed bonus expense removal is overstated by $86,000. I have therefore increased the Company's proposed pro forma test year O&M expenses by $86,000.

[3] See response to AG-1-17.

- **Pension Expenses**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION WITH REGARD TO PENSION EXPENSES IN THIS CASE?

A. In its original filing schedules, Delta proposed to reflect for ratemaking purposes in this case the actual per books 2003 pension expenses of approximately $500,000. However, in its responses to PSC-2-25 z. and AG-1-9, Delta now suggests that its originally filed pension expense of approximately $500,000 should be replaced by a pension expense of approximately $725,000, representing the latest actuarially determined Delta pension expenses for the 12-month period ended June 30, 2004.

Q. DO YOU AGREE WITH THIS POSITION?

A. No. As described in AG-2-11, the pension expense of approximately $725,000 does not reflect the recent upswing in the equity markets and associated rebound in Delta's pension plan assets. For example, this is reflected by the fact that the actual return on pension assets for the 12-month period ended June 30, 2004 will be $1,774,000 as opposed to the Expected Return on Assets of $671,000 that is reflected as a credit component in the calculation of the pension expense of $725,000. In its response to AG-2-11, Delta indicates that this actual turn-around in the pension plan's return on assets is expected to result in a $90,000 reduction in the pension expense component for the amortization of Unamortized Losses. In addition, since the pension plan assets have experienced such a significant increase as a result of the recent upswing in the equity markets, it can also be expected that

[4] See response to PSC-3-12 b, p. 2 of 9.

the Expected Return on Assets credit component of Delta's pension expense will see a significant increase from the $671,000 currently reflected in the pension expense of $725,000. Thus, I believe that Delta is inappropriately attempting to lock into base rates an abnormally high level of pension expense that will probably decline in the immediately following years. Based on the foregoing information, it is my opinion that the actual per books test year pension expense of approximately $500,000 could well be considered an appropriate expense level representative of Delta's pension expenses in the near-term future. I have therefore not recommended an adjustment to Delta's test year per books pension expenses.

- **401(k) Expense Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO DELTA'S PROPOSED TEST YEAR 401(K) EXPENSES, AS SHOWN ON SCHEDULE RJH-7, LINE 5.

A. The Company's actual 401(k) expenses for the 2003 test year amount to $132,894 as compared to corresponding 401(k) expenses of $170,244 in 2002. While the Company reflected the unadjusted 2003 test year expense amount of $132,894 for ratemaking purposes in its original filing schedules, during the course of this proceeding it found that this test year expense amount was understated by $23,833 and should have been $156,727. As explained by Delta in its responses to PSC-2-25 aa. and AG-1-9, the reason for this test year 401(k) expense understatement is due to the timing of invoices received. Based on my review of this issue, I take no exception to Delta's suggested restatement of test year 401(k) expenses by $23,833. I have therefore increased the Company's proposed pro forma test year O&M expenses by that amount.

- **Rate Case Expense Adjustment**

Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO THE RATE CASE EXPENSES ASSOCIATED WITH THIS PROCEEDING?

A. The Company has estimated that it will incur rate case expenses of $250,000 and has proposed to amortize these expenses over a 3-year period, "consistent with the treatment of this item in our last rate case."[5] Thus, the Company is proposing an annualized rate case expense level of $83,333.

Q. DO YOU AGREE WITH DELTA'S PROPOSED 3-YEAR AMORTIZATION PERIOD?

A. No. It is this Commission's policy to base the amortization period for rate case expenses on the normalized interval between Delta's rate cases. For example, in the Company's 1997 rate case (Case No. 97-066), the interval between that case and Delta's prior rate case was almost 6 ½ years. On page 13 of its Order in Case No. 97-066, the Commission made the following ruling with regard to this issue:

> The Commission finds that these costs should be recovered over a 5-year period to reflect the interval between Delta's rate filings.

In Delta's next case, Case No.99-176, the interval between that case and Case No. 97-066 was slightly more than 2 years. In that case, the Commission agreed with Delta's proposal to use a 3-year amortization period in order "to reflect the normal interval between Delta's general rate adjustment applications."[6] When Delta witness Hall was asked by the Commission in Case No. 99-176 why he had proposed a 3-year amortization period rather than the 5-year amortization period authorized by the Commission in Case No. 97-066, his response was:

> In Case No. 97-066 it had been six (6) years between Delta's cases. In Case No. 99-176 it has only been two (2) years between this case and Delta's prior case, thus the reason to use a 3-year amortization period for the expense in this case.

The interval between the instant proceeding (Case No. 2004-00067) and Case No. 99-176 is approximately 4 ¾ years. Based on this evidence, I disagree with the Company's proposal in this case to use a 3-year amortization period. The average rate case interval between Case No. 97-066, Case No. 99-176 and the current case is approximately 4 ¼ years. For this reason, I recommend a rate case amortization period of 4 years.

Q. WHAT RATE CASE EXPENSE LEVEL HAVE YOU REFLECTED AT THIS TIME?

A. Following Commission ratemaking policy, I recommend that rate recognition be given to all actual rate case expenses prudently incurred by Delta to process this rate case. At this time, it is not known whether this case will be fully litigated or settled and we do not know the actual rate case expense levels associated with these two scenarios. In anticipation of a possible settlement of this case, I have at this time reflected total rate case expenses of $150,000.

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[5] See page 5, lines 8-9 of Mr. Hall's testimony.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS ON THE COMPANY'S PROPOSED ANNUAL RATE CASE EXPENSE AMORTIZATION AMOUNT?

A. As shown on schedule RJH-9, my recommendations reduce the Company's proposed annual rate case expense amortization by $45,833.

- **Directors Fees and Expenses**

Q. HOW ARE DELTA'S DIRECTORS COMPENSATED FOR THE PERFORMANCE OF THEIR DUTIES?

A. As indicated in the response to PSC-2-28, Delta's directors are compensated by way of monthly retainer fees rather than per diems or meeting fees.

Q. WHAT HAS BEEN THE HISTORY OF DELTA'S DIRECTORS FEES AND EXPENSES?

A. The table below shows Delta's actual directors fees and expenses for the test year and the 5 years prior to the test year:

1998	$ 88,800
1999	$ 87,460
2000	$120,317
2001	$157,746
2002	$165,979
2003 Test Year	$225,369

The data in the above table indicate that Delta's directors fees and expenses have steadily

[6] See page 21 of the KPSC's Order in Case No. 99-176.

increased and are currently almost three times the level experienced in 1998.

Q. DO DELTA'S TEST YEAR DIRECTORS FEES INCLUDE BONUS COMPENSATION FOR THE DIRECTORS?

A. Yes. As shown in the response to AG-1-38, directors retainer fees make up only $149,500 of the total test year directors fees and expenses of $225,369. The remaining costs are for directors bonuses ($51,440), directors stock ($20,538) and some expenses.

Q. HAS DELTA ACKNOWLEDGED THAT THE DIRECTORS BONUSES INCLUDED IN THE TEST YEAR DIRECTORS FEES REPRESENT NON-RECURRING EXPENSES?

A. Yes. Delta acknowledged this in its response to AG-1-9.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING INFORMATION?

A. I recommend that the Company's test year directors fees and expenses of $225,369 be reduced by $51,440 to remove the non-recurring directors bonuses. This would also be consistent with Delta's proposal in this case to remove the $403,865 bonuses paid out to Delta's management in the test year for the reason that it would be inappropriate to charge such expenses to the ratepayers.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS TO THE COMPANY'S PROPOSED TEST YEAR DIRECTORS FEES AND EXPENSES?

A. Yes. As shown in the response to PSC-2-25 cc., Delta's test year directors fees and expenses include $686 worth of expenses for a director's Christmas dinner and certain Christmas gifts. I have also removed these expenses because I do not believe that these expenses produce any material benefits to the ratepayers.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS ON THE COMPANY'S TEST YEAR DIRECTORS FEES AND EXPENSES?

A. As shown on schedule RJH-10, my recommendations reduce the Company's test year directors fees and expenses by $52,126 to an adjusted pro forma directors fees and expense amount of $173,243.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In response to PSC-3-13, Delta states that in March 2004 the Company's Nominating and Compensation Committee further increased the directors retainer fees to $205,200 on an annualized basis. Since this cost change falls outside of the 2003 test year, I do not believe that the KPSC should give rate recognition to this item. Doing so would inappropriately violate the test year matching principle.

- **Outside Services – Accounting Expense Adjustment**

Q. PLEASE EXPLAIN THE ISSUE WITH REGARD TO OUTSIDE SERVICES – ACCOUNTING EXPENSES.

A. The Company's 2003 test year Outside Services – Accounting expenses in Account 923.020 as compared to the corresponding expenses in the 5 years prior to the test year were as follows:

1998	92,483
1999	80,400
2000	85,590
2001	93,600
2002	92,851
2003 Test Year	343,748

The data in the above table strongly suggest that the test year per books expense level is abnormally high and not representative of what can be expected on an ongoing annual basis Yet, the Company has proposed to reflect the actual test year expense of $343,748 for ratemaking purposes in this case.

Q. DID YOU REQUEST DELTA TO INDICATE TO WHAT EXTENT THE TEST EXPENSE AMOUNT OF $343,748 CONTAINS ITEMS THAT DO NOT RECUR ON AN ANNUAL BASIS?

A. Yes. Delta was asked this information in AG-1-48. In response to that data request, Delta indicated that the reason for the high test year expense level of $343,748 is that it includes $240,727 of new Sarbanes/Oxley related accounting expenses. The response to AG-1-48 also clearly indicates that out of these $240,727 Sarbanes/Oxley accounting expenses, a total of $163,328 represents non-recurring Sarbanes/Oxley consulting expenses, leaving $180,420 of recurring test year accounting expenses.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE AFOREMENTIONED INFORMATION?

A. Based on the previously discussed information, I recommend that the Company's proposed test year Outside Service – Accounting expenses in account 923.020 be reduced by the non-recurring expense portion of $163,328. My recommendation is shown on schedule RJH-11.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In its response to AG-1-48 B., Delta also claimed that the recurring accounting expense amount of $180,420 is understated because the Company expects that in subsequent years it will be required to pay its external auditors for issuing a report on internal controls. Delta claims that such an audit will start in March 2005 with an estimate cost of $80,000. The Company therefore maintains that the pro forma level of recurring test year accounting expenses should be set at approximately $260,000.[7] There are several reasons why I do not agree with this proposed position. First, this new internal control audit is not expected to start until March 2005, a point in time that falls 15 months after the end of the 2003 test year used in this case. Recognizing this kind of selective post-test year expense would violate the test year principle of consistent quantification of all components of the revenue requirement. Second, the estimated audit cost of $80,000 is not a known

[7] Derived as $180,000 + $80,000.

and measurable expense at this time. For these reasons, the Company's argument that this estimated $80,000 expense be included in the pro forma test year operating expenses should be rejected by the Commission.

- **Outside Services – Computer Expense Adjustment**

Q. WHAT IS THE ISSUE WITH REGARD TO OUTSIDE SERVICE – COMPUTER EXPENSES?

A. In its response to PSC-2-36 g., Delta confirmed that the test year computer expenses associated with scanning services by Source Imaging do not represent annual recurring charges. As shown in the response to PSC-1-28, these test year Source Imaging expenses amount to $42,404. Based on this information, I recommend that these non-recurring charges of $42,404 be removed from the test year operating expenses. My recommendation is reflected on schedule RJH-12.

- **Miscellaneous Expense Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS EXPENSE ADJUSTMENTS SHOWN ON SCHEDULE RJH-13.

A. First, I recommend that an additional lobbying expense amount of $758 be removed from test year operating expenses based on the information listed in footnote (1) of schedule RJH-13.

Second, I recommend the removal from test year operating expenses $7,389 of the Company's American Gas Association (AGA) dues that are associated with public affairs and institutional advertising. The calculations to derive this expense disallowance of $7,389 are detailed in footnote (2) of schedule RJH-13. The AGA has the following definition for the purpose of its public affairs department:

> Provides members with information on legislative developments; prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.

The AGA's advertising activities are institutional and promotional in nature and are not specifically directed to Delta's service territory. I do not believe that these AGA expenses should be recognized for ratemaking purposes as they produce no material benefit to the ratepayers.

Third, I have removed from test year operating expenses $44,200 worth of incentive expenses recorded in Account 930.110. In its response to AG-1-43, Delta concedes that these incentive expenses in Account 930.110 should have been excluded for ratemaking purposes in this case.

Fourth, I have removed $19,886 for expenses associated with employee gifts, award banquets, parties and other social events. Based on my review of prior Commission Orders,[8] it is my understanding that the Commission has a ratemaking policy of removing the previously referenced expense types from rate consideration. I would agree that these types of expenses have nothing to do with the provision of safe and reliable gas service and,

[8] Particularly KPSC Orders involving Kentucky-American Water Company, such as the KPSC's Orders in Case

therefore, should not be charged to the ratepayers.

Fifth, I have removed $4,914 worth of promotional and economic development expenses included in Account 930.090. Footnote (5) of schedule RJH-13 references the expense line items to be disallowed and the data response where these expense line items can be found. I have disallowed these expenses based on my opinion that have nothing to do with the provision of safe and reliable gas service and produce no material benefit to the ratepayers.

Sixth, I have removed $2,749 worth of employee membership expenses included in Account 921.070. Footnote (6) of schedule RJH-13 references the expense line items to be disallowed and the data response where these expense line items can be found. I have disallowed these expenses for the same reasons as mentioned above.

Seventh, in accordance with KPSC ratemaking policy, I have removed $264 worth of spousal expenses that are included in Delta's proposed test year operating expenses.

Eighth, I have removed $5,161 worth of lobbying and economic development expenses included in Account 921.220. Footnote (8) of schedule RJH-13 references the expense line items to be disallowed and the data response where these expense line items can be found. I have disallowed these expenses for the same reasons as mentioned above.

Finally, I have removed $2,022 worth of lobbying and community relations expenses

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Nos. 97-034, 95-554, 90-321, 89-348 and 10481.

included in Account 921.290. Footnote (9) of schedule RJH-13 references the expense line items to be disallowed and the data response where these expense line items can be found. I have disallowed these expenses for the same reasons as mentioned above.

Q. HOW DO THE PREVIOUSLY DESCRIBED MISCELLANEOUS EXPENSE ADJUSTMENTS IMPACT THE COMPANY'S PROPOSED TEST YEAR OPERATING EXPENSES?

A. As shown on schedule RJH-13, line 10, the previously described miscellaneous expense adjustments decrease Delta's proposed test year operating expenses by $87,343.

- **<u>Depreciation Expenses</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENTS TO DELTA'S PROPOSED PRO FORMA DEPRECIATION EXPENSES IN THIS CASE, AS SHOWN ON SCHEDULE RJH-14.

A. First, I have reflected the pro forma annualized depreciation expenses recommended by the AG's depreciation expert, Michael Majoros. This has the effect of reducing the Company's proposed pro forma depreciation expenses by $747,744.

Second, as confirmed by Delta in its response to AG-2-2, the Company's proposed pro forma depreciation expenses did not – but should – include a net $12,000 expense credit for the Tranex and Mt Olivet Acquisition Adjustment amortizations. My recommended adjustment shown on schedule RJH-14, line 2 corrects for this oversight.

- **Payroll Tax Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO DELTA'S PROPOSED OTHER TAXES, AS SHOWN ON SCHEDULE RJH-5, LINE 5.

A. The recommended adjustment to increase Delta's proposed Other Taxes by $4,263 represents the payroll tax increase associated with my recommended bonus removal expense adjustment that was discussed earlier in this testimony.

- **Income Taxes**

Q. DID YOU CALCULATE THE RECOMMENDED PRO FORMA TEST YEAR INCOME TAXES IN THIS CASE IN A MANNER CONSISTENT WITH THE TAX CALCULATION APPROACH USED BY DELTA IN THIS CASE?

A. Yes. Delta's proposed and the AG's recommended pro forma income tax calculations are shown on schedule RJH-15. As shown there, I have used the same tax calculation approach as Delta. The only reason why the AG's and Delta's calculated pro forma test year income taxes are different is because of differences in pro forma test year taxable income positions.

C. REVENUE CONVERSION FACTOR

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO YOUR RECOMMENDED REVENUE CONVERSION FACTOR TO BE USED FOR

RATEMAKING PURPOSES IN THIS CASE.

A. As shown on schedule RJH-1, line 6, the Company's proposed Revenue Conversion Factor is approximately 1.6513912 whereas the AG's recommended Revenue Conversion Factor is approximately 1.6544073. As can be seen from the Revenue Conversion Factor calculations in footnote (2) of schedule RJH-1, the AG's proposed factor takes into account that any annual revenue change to be authorized by the PSC in this case will have a corresponding impact on the PSC assessment fees. The PSC assessment rate was derived from the Company's response to PSC-3-25. Delta's proposed revenue conversion factor did not reflect this revenue conversion factor component. Hence, the Company's proposed revenue conversion factor is slightly lower than the AG-recommended factor.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

In Re the Matter of:

AN ADJUSTMENT OF THE RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	**CASE NO: 2003-00433**

AFFIDAVIT

Comes the affiant, Robert J. Henkes, and being duly sworn states that the foregoing testimony and attached schedules were prepared by him are, to the best of his information and belief, true and correct.

____

State/Commonwealth of CT
County of Fairfield

Subscribed and sworn to before me by the Affiant Robert J. Henkes this the 24th day of June, 2004.

____
Notary Public, State at Large

MARIA RIGAKOS
NOTARY PUBLIC
My Commission Expires January 31, 2008

DELTA NATURAL GAS COMPANY
SUMMARY OF REVENUE REQUIREMENT POSITIONS

	Delta (1)	Adjustments	AG	
1. Rate Base	$ 111,071,658	$ 680,287	$111,751,945	Sch. RJH-3
2. Rate of Return	8.549%		7.640%	Sch. RJH-2
3. Income Requirement	9,496,008		8,537,316	
4. Pro Forma Income	6,905,785	806,813	7,712,598	Sch. RJH-5
5. Income Deficiency	2,590,223		824,718	
6. Revenue Conversion Factor	1.6513912		1.6544073	(2)
7. Revenue Deficiency	$ 4,277,471	$ (2,913,052)	$ 1,364,420	

(1) FR 10(7)(a) and Delta filing Schedules 1, 7, 8 and 9.

(2)	Delta	AG	
Revenues	100.0000000	100.0000000	
Less: PSC Fees	-	(0.1823000)	(3)
	100.0000000	99.8177000	
Less: State Income Tax @ 8.25%	(8.2500000)	(8.2349603)	
	91.7500000	91.5827398	
Less: Federal Income Tax @ 34%	(31.1950000)	(31.1381315)	
Net Income Factor	60.5550000	60.4446082	
Revenue Conversion Factor	1.6513912	1.6544073	

(3) Response to PSC-3-25

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Sch. RJH-2

DELTA NATURAL GAS COMPANY
ADJUSTED CAPITALIZATION AT 12/31/03 AND OVERALL RATE OF RETURN

DELTA PROPOSED:	Adjusted Actual 12/31/03 Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Equity	$ 42,865,046	37.15%	12.500%	4.643%
2. Long Term Debt	54,824,000	47.51%	7.422%	3.526%
3. Short Term Debt	17,707,889	15.35%	2.478%	0.380%
4. Total	$ 115,396,935	100.00%		8.549%

AG RECOMMENDED:	Adjusted Actual 12/31/03 Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Equity	$ 42,865,046	37.15%	10.050% (2)	3.733%
2. Long Term Debt	54,824,000	47.51%	7.422%	3.526%
3. Short Term Debt	17,707,889	15.35%	2.478%	0.380%
4. Total	$ 115,396,935	100.00%		7.640%

(1) Delta filing Schedule 9
(2) Testimony of Charly King

Case No. 2004-00067
Test Year Ended 12/31/03

Sch. RJH-3

DELTA NATURAL GAS COMPANY
RATE BASE

	Delta (1)	Adjustments	AG	
1. Plant in Servivce	$ 165,994,418		$ 165,994,418	
2. Depreciation Reserve	(52,964,026)		(52,964,026)	
3. Net Plant in Service	113,030,392		113,030,392	
4. Cash Working Capital	1,290,427	(40,017)	1,250,410	Sch. RJH-4
5. Prepayments	351,876	(39,440) (2)	312,436	
6. Materials and Supplies	478,139		478,139	
7. Gas in Storage	6,363,748		6,363,748	
8. Accum. Def. Income Taxes	(14,697,866)		(14,697,866)	
9. Unamortized Debt Expense	4,185,070		4,185,070	
10. Advances in Construction	(105,692)		(105,692)	
11. Depreciation Adjustment	145,431	759,744	905,175	Sch. RJH-14, L5
12. Unrecovered SFAS 143 Costs	30,133		30,133	
13. TOTAL NET RATE BASE	$ 111,071,658	$ 680,287	$ 111,751,945	

(1) Delta filing Schedule 7
(2) Per response to AG-1-5. Remove KPSC assessments from prepayment balance.

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Sch. RJH-4

DELTA NATURAL GAS COMPANY
CASH WORKING CAPITAL

	Delta (1)	Adjustments	AG	
1. Pro Forma O&M Expenses	$ 10,323,416	$ (320,132)	$ 10,003,284	Sch. RJH-5, L3
2. CWC Ratio	0.125		0.125	
3. Cash Working Capital	$ 1,290,427	$ (40,017)	$ 1,250,410	

(1) Delta filing Schedule 1, line 2 and Schedule 7, line 4

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Sch. RJH-5

DELTA NATURAL GAS COMPANY
PRO FORMA OPERATING INCOME

		Delta (1)	Adjustments	AG	
1.	Operating Revenues	$ 57,709,948	$ 239,331	$ 57,949,279	Sch. RJH-6A, L4
	Operating Expenses:				
2.	Purchased Gas Cost	33,364,884		33,364,884	
3.	O&M Expenses	10,323,416	(320,132)	10,003,284	Sch. RJH-7
4.	Depreciation	4,045,073	(759,744)	3,285,329	Sch. RJH-14, L3
5.	Other Taxes	1,505,464	4,263	1,509,727	(2)
6.	Operating Exp. w/o Income Tax	49,238,837	(1,075,613)	48,163,224	
7.	Income Taxes	1,565,326	508,131	2,073,457	Sch. RJH-15
8.	Total Operating Expenses	50,804,163	(567,482)	50,236,681	
9.	Operating Income [L1 - L8}	$ 6,905,785	$ 806,813	$ 7,712,598	

(1) FR 10(7)(a)
(2) Response to PSC-3-12 b., page 4 of 9, revised filing Schedule 6. Adjustment is for Bonus Taxes.

DELTA NATURAL GAS COMPANY
NET REVENUE ADJUSTMENT FOR TEST YEAR-END CUSTOMER GROWTH
[METHOD I]

	1	2	3	4	5	6	7	8	9	10
	Test Yr. Customers 12/31/03	Test Yr. Customers 13-mos Avg	12/31/03 vs. Avg Growth	Annual Cust. Charge	Add'l Cust. Ch. Rev.	Test Yr. MCF Sales	Avg. Sales Per Cust.	Cons. Base Rate per MCF	Add'l MCF Usage Charge Rev.	Total Incremental Revenues
	(a)	(b)	[1 - 2]	(c)	[3 x 4]	(d)	[6 / 2]	(e)	[3 x 7 x 8]	[5 + 9]
1. Residential	34,100	33,759	341	$ 96.00	$ 32,736	2,316,920	68.63	$ 3.6224	$ 84,776	
2. Small Non-Residential	4,629	4,491	138	$ 204.00	$ 28,152	702,702	156.47	$ 3.5800	$ 77,302	
3. Large Non-Residential	872	868	4	$ 600.00	$ 2,400	987,090	1,137.20	$ 3.0700	$ 13,965	
4. Revenue Adjustment					$ 63,288				$ 176,043	$ 239,331
5. Associated Incremental Costs at Operating Ratio of 12.40% (f):										(29,677)
6. Recommended Net Incremental Revenues										$ 209,654

(a) Responses to PSC-1-44, p.2 and AG-1-30, p. 6 of 6
(b) Calculated from responses to PSC-1-44 and AG-1-30. Confirmed in response to AG-1-32.
(c) Delta's present tariffs, e.g., monthly residential customer charge of $8.00 is annual charge of 12 x $8.00. or $96.00.
(d) Delta filing Schedule 2 & 3
(e) Delta's present tariffs. The usage rates for Small Non-Residential ($3.58) and Large Non-Residential ($3.07) represent weighted average rates based on weighting factors used by Delta in its prior Case No. 899-176 on Walker Exhibit 5.

(f) Operating Ratio Calculation:

- Test Year per books O&M expenses excluding cost of gas:	$ 10,548,848
- Less: Payroll expenses[Hall WP-4.1]	(4,683,924)
- Less: Employee pensions and benefits[2003 FERC Form1, p. 323]	(2,716,909)
- Less: Regulatory commission expense [2003 FERC Form 2, p.323]	(143,222)
- Net O&M expenses	$ 3,004,793
- 2003 per books revenues net of GCR revenues [Delta filing Sch. 2 & 3]	$ 24,229,318
- Operating Ratio[net O&M expense/revenues net of GCR]	12.40%

DELTA NATURAL GAS COMPANY
NET REVENUE ADJUSTMENT FOR TEST YEAR-END CUSTOMER GROWTH
[METHOD II]

	1	2	3	4	5	6	7	8	9	10
	Test Yr. Customers 13-mos Avg	1/2 Yr Compound Growth Rate	1/2 Yr Cust. Growth	Annual Cust. Charge	Add'l Cust. Ch. Rev.	Test Yr. MCF Sales	Avg. Sales Per Cust.	Cons. Base Rate per MCF	Add'l MCF Usage Charge Rev.	Total Incremental Revenues
	(a)	(b)	[1 x 2]	(c)	[3 x 4]	(d)	[6 / 1]	(e)	[3 x 7 x 8]	[5 + 9]
1. Residential	33,759	0.505%	170.5	$ 96.00	$ 16,366	2,316,920	68.63	$ 3.6224	$ 42,384	
2. Small Non-Residential	4,491	0.875%	39.3	$ 204.00	$ 8,016	702,702	156.47	$ 3.5800	$ 22,012	
3. Large Non-Residential	868	0.265%	2.3	$ 600.00	$ 1,380	987,090	1,137.20	$ 3.0700	$ 8,030	
4. Revenue Adjustment					$ 25,763				$ 72,426	$ 98,189
5. Associated Incremental Costs at Operating Ratio of 12.40% (f):										(12,175)
6. Recommended Net Incremental Revenues										$ 86,014

(a) Calculated from responses to PSC-1-44 and AG-1-30. Confirmed in response to AG-1-32.
(b) Calculation of 1/2 yr. compound growth rate:

	Response to AG-1-30 - # of Customers			
	Avg. Res.	Avg. Small Non-Res.	Avg. Large Non-Res.	
1998	32,111	4,118	NA	
1999	32,785	4,249	849	
2000	33,609	4,386	859	
2001	33,696	4,437	868	
2002	33,756	4,458	875	
2003	33,759	4,491	868	
5-Yr. compound average annual growth rate	1.01%	1.75%	0.53%	(4-Yr. avg)
1/2 of compound average annual growth rate	0.505%	0.875%	0.265%	

(c) Delta's present tariffs, e.g., monthly residential customer charge of $8.00 is annual charge of 12 x $8.00. or $96.00.
(d) Delta filing Schedule 2 & 3
(e) Delta's present tariffs. The usage rates for Small Non-Residential ($3.58) and Large Non-Residential ($3.07) represent weighted average rates based on weighting factors used by Delta in its prior Case No. 899-176 on Walker Exhibit 5.
(f) For operating ratio calculation, see footnote (f) on Schedule RJH-

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Test Year Ended 12/31/03

Sch. RJH-7

DELTA NATURAL GAS COMPANY
ADJUSTED OPERATION AND MAINTENANCE EXPENSES

1.	Adjusted O&M Expenses Proposed by Delta	$ 10,323,416	(1)
	AG-Recommended O&M Expense Adjustments:		
2.	Expense Increase Associated With Cust. Growth Rev. Adj.	29,677	Sch. RJH-6A, L5
3.	Remove Interest on Customer Deposits	(33,554)	(1)
4.	Adjustment to Bonus Removal	86,000	(2)
5.	401(k) Expense Adjustment	18,456	Sch. RJH-8
6.	Rate Case Expense Adjustment	(45,833)	Sch. RJH-9
7.	Directors Fees and Expense Adjustment	(52,126)	Sch. RJH-10, L4
8.	Outside Services - Accounting Expense Adjustment	(163,328)	Sch. RJH-11
9.	Outside Services - Computer Expense Adjustment	(42,404)	Sch. RJH-12
10.	Miscellaneous Expense Adjustments	(87,343)	Sch. RJH-13
11.	Total AG-Recommended O&M Expense Adjustments	(320,132)	
12.	Adjusted O&M Expenses Recommended by AG	$ 10,003,284	

(1) Delta filing Schedule 4

(2) Response to PSC-3-12 b., page 2 of 9, revised filing Schedule 4: Bonus removal of $317,865 vs. $403,865.

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Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
401(K) EXPENSES

	Delta	Adjustments	AG
	(1)		
1. 401(k) Costs	$ 132,894	$ 23,833	$ 156,727 (2)
2. O&M Expense Ratio		77.44% (3)	
3. 401(k) Expense Increase		$ 18,456	

(1) Responses to PSC-1-20 b. and PSC-1-46, line 11.
(2) Response to PSC-1-25 aa and PSC-3-12 d.
(3) Response to AG-2-10 c.

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Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
RATE CASE EXPENSES

	Delta (1)	Adjustments	AG
1. Current Rate Case Expense Claim	$ 250,000		$ 150,000
2. Amortization Period (Yrs)	3		4
3. Annual Expense Amortization	$ 83,333	$ (45,833)	$ 37,500

(1) Hall WP-4.2

Sch. RJH-10

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Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
DIRECTORS FEES AND EXPENSES

1.	Delta's Proposed Test Year Directors Fees and Expenss	$ 225,369	(1)
	AG-Recommended Adjustments:		
2.	Remove Non-Recurring Directors Bonuses	(51,440)	(2)
3.	Remove Christmas dinner and Christmas gift expenses	(686)	(3)
4.	Total AG Expense Adjustments	(52,126)	
5.	AG-Recommended Outside Services - Accounting Expenses	$ 173,243	

(1) Responses to PSC-1-20 b.
(2) Response to AG-1-9
(3) Response to PSC-2-25 cc.: $349 + $337 = $686

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Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
OUTSIDE SERVICES - ACCOUNTING EXPENSES

1.	Test Year Per Books Outside Services - Accounting Expenses Reflected by Delta	$ 343,748 (1)
	AG-Recommended Adjustments:	
2.	Remove Non-Recurring Sarbane/Oxley Related Expenses	(163,328) (2)
3.	AG-Recommended Outside Services - Accounting Expenses	$ 180,420

(1) Response to PSC-1-20 b.
(2) Response to AG-1-48

Case No. 2004-00067
Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
OUTSIDE SERVICES - COMPUTER EXPENSES

1.	Test Year Per Books Outside Services - Computer Expenses Reflected by Delta	$ 155,951 (1)
	AG-Recommended Adjustments:	
2.	Remove Non-Recurring Scanning Service Expenses	(42,404) (2)
3.	AG-Recommended Outside Services - Computer Expenses	$ 113,547

(1) Response to PSC-1-20 b.
(2) Responses to PSC-2-36 g. and PSC-1-28 (Source Imaging Scanning Services)

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Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1.	Removal of Additional Lobbying Expenses	$	(758)	(1)
2.	Remove AGA Dues Associated with Public Affairs and Institutional Advertising		(7,389)	(2)
3.	Removal of Incentive Expenses in Acct. 930.110		(44,200)	(3)
4.	Removal of Expenses for Employee Gifts and Award Banquets, Social Events and Parties		(19,886)	(4)
5.	Removal of Promotional and Economic Development Expenses Included in Acct. 930.090		(4,914)	(5)
6.	Removal of CertainEmployee Membership Exp. in Acct. 921.070		(2,749)	(6)
7.	Removal of Spousal Expenses from Acct. 921.21		(264)	(7)
8.	Removal of Lobbying and Econ. Devel. Exp. From Acct. 921.220		(5,161)	(8)
9.	Removal of Lobbying and Community Relations Exp in Acct 921.29		(2,022)	(9)
10.	Total Miscellaneous Expense Adjustments	$	(87,343)	

(1) Per response to AG-1-37: total test year lobbying expense of $16,821 vs. $16,083 of test year lobbying expense removed by Delta on filing Schedule 4 ($15,280 + $783)
(2) Per response to AG-1-39: test year AGA dues of $27,277 x 27.09% for public affairs (25.63%) and advertising (1.46%)
(3) Response to AG-1-43
(4) Response to AG-1-26
(5) Per response to AG-1-42: removed expenses in line items 5, 27, 31-33, 35, 42, 45, 47, and 49.
(6) Per response to AG-1-45 a.: removed expenses for check nos. 212155, 216763, 214857, 216453, 215708, 213811, 200671
(7) Response to PSC-3-23
(8) Per response to AG-1-45 b.: removed expenses in acct. 921.220 line items 29-35, 43, 55-56, 62.
(9) Per response to AG-!-45 c.: removed expenses in acct. 921.29 line items 162, 216, 232, 234, 243, 248, 251, 258, 284-285, 288, 295, 299, 302, 321, 330, 351.

Case No. 2004-00067
Test Year Ended 12/31/03

DELTA NATURAL GAS COMPANY
PRO FORMA DEPRECIATION EXPENSES

	Delta (1)	Adjustments	AG	
1. Pro Forma Depreciation Expense	$ 4,045,073	$ (747,744)	$ 3,297,329	(2)
2. Net Amortization of Tranex and Mt Olivet Acquisition Adjustments	-	(12,000)	(12,000)	(3)
3. Total Pro Forma Depr./Amort. Exp	4,045,073	(759,744)	3,285,329	
4. Per Books Test Year Depr. Exp.	4,190,504		4,190,504	
5. Depreciation Expense Adj.	$ (145,431)	$ (759,744)	$ (905,175)	

(1) Delta filing Schedule 5
(2) Testimony of Michael Majoros
(3) Responses to AG-1-4b.3 and AG-2-2

DELTA NATURAL GAS COMPANY
PRO FORMA INCOME TAXES

	Delta (1)	Adjustments	AG	
1. Operating Revenues	$ 57,709,948	$ 239,331	$ 57,949,279	Sch. RJH-5, L1
2. Operating Expenses w/o Income Tax	49,238,837	(1,075,613)	48,163,224	Sch. RJH-5, L6
3. Pro Forma Interest Expense	4,338,709	26,743	4,365,452	(2)
4. Taxable Income	4,132,402	1,288,201	5,420,603	
5. Combined FIT and SIT	39.445%		39.445%	
6. Income Taxes	1,630,026	508,131	2,138,157	
7. ITC Amortization	(39,200)		(39,200)	
8. Amortization of Excess Deferred Tax	(25,500)		(25,500)	
9. Pro Forma Adjusted Income Taxes	$ 1,565,326	$ 508,131	$ 2,073,457	

(1) Delta filing Schedule 8, p. 2

	Delta	AG	
(2) Rate Base	$ 111,071,658	$ 111,751,945	Sch. RJH-3
Weighted Cost of Debt in Overall ROR	3.906%	3.906%	Sch. RJH-2
Pro Forma Interest Expense	$ 4,338,709	$ 4,365,452	

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	8/2003

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company	Docket 3518-U	08/1985

Base Rate Proceeding

Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001

Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980

Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company	Docket 757-769	07/1975

Water Base Rate Proceeding		
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982

Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991

Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995

Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997

Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999

Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	Docket No.GR99070509 Docket No. GR99070510	03/2000 03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000

Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001

Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company	Docket No. EO02110853	12/2002

Minimum Pension Liability Proceeding		
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003
Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003
Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003
Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company	Docket No. WR03110900	4/2004

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

I/M/O AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	**)) CASE NO. 2004-00067)**

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

Date: July 2, 2004

Introduction

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

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), an economic consulting firm located at 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience. It also contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the subject of this testimony?

A. This testimony addresses depreciation.

Q. Do you have any specific experience in the field of public utility depreciation?

A. Yes. I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country. I have testified in over one hundred proceedings on the subject of public utility depreciation and represented various clients in several other proceedings in which depreciation was an issue but was settled. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commissions' ("FCC") Triennial Depreciation Represcription conferences.

Q. Does your experience specifically include gas company depreciation?

A. Yes. I have addressed the subject of gas company depreciation in several proceedings.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I have been asked to review the depreciation-related testimony and exhibits of Delta Natural Gas Company, Inc. ("Delta" or "the Company"). I was asked to express an opinion regarding the reasonableness of the Company's depreciation expense proposal and, if warranted, make alternative recommendations.

Company's Depreciation-Related Proposals

Q. Will you please summarize the Company's depreciation proposal?

A. Yes. Mr. Seelye sponsors the Company's depreciation study and the resulting depreciation claims. Mr. Seelye states that "by and large, [his] depreciation study indicated that many of Delta's current depreciation accrual rates should be lowered."[1] I agree, however, I find that more of a decrease is warranted. Mr. Seelye's results translate into a $145 thousand test year depreciation expense decrease.

Results of Seelye's Depreciation Study

Seelye Depreciation Expense	$4,045,073
Per Books	4,190,504
Decrease	($ 145,431)

Current Depreciation Rates

Q. What is the source of Delta's current depreciation rates?

A. Many of Delta's current rates have been in use for several decades, and the Company does not appear to know how they were originally calculated, or what Commission Order set the rates.[2] However, a few have been reduced since then, as discussed in the Company's response to Attorney General Data Request No. 69. For instance, the depreciation rates for Accounts 367 and 376 were reduced from 3% to 2.9% and 2.5%, respectively, in November 1985 pursuant to the Commission's Order in Case No. 9331. The depreciation rate for Account 367 was further reduced to 2.5% in June 1991. The rates for Accounts 3653 and 380 were also reduced at that time, from 3% to 2.5%. The

[1] Direct Testimony of William Steven Seelye, page 22.
[2] Responses to 1-AG-69 and 71.

depreciation rate for Account 2992 was reduced from 33% to 10%, and the rate for Account 3993 was reduced from 20% to 10% in December 1991.[3]

Q. How are the present rates calculated?

A. The Company does not know how the present rates are calculated. Attorney General Data request No. 71 asked for the derivation of the current depreciation rates. The Company responded, "Delta does not have a copy of the workpapers or study used to derive the current depreciation rates. The same depreciation rates have been in effect since at least the 1970s."[4] In its response to Attorney General Supplemental Data Request No. 30, which asked for all information Delta is aware of concerning the existing depreciation rates, the Company stated the following:

> All information Delta is aware of concerning the existing depreciation rates was provided in response to 1-AG-71. Delta could not locate a copy of the study (or studies) used to develop the current depreciation rates, and is unaware of the assumptions made to develop those rates.[5]

<u>Summary and Conclusions</u>

Q. What do you recommend?

A. I recommend an $893 thousand depreciation decrease based on plant as of December 31, 2003.

Q. Why do you disagree with Mr. Seelye's depreciation expense proposals?

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[3] Response to 1-AG-69.
[4] Response to 1-AG-71.
[5] Response to 2-AG-30.

A. I have several disagreements but overall, I must state that it is evident that Mr. Seelye is new to the depreciation business. Otherwise, his study probably would have focused more attention on details. My specific points of disagreement are the following:

- Mr. Seelye has understated at least three of the Company's plant lives. This renders the resulting depreciation rates excessive.
- Mr. Seelye used the wrong technique to calculate the depreciation rates in the Storage and Processing function.
- Mr. Seelye has incorporated net salvage rates within his depreciation rates. I recommend that recovery for net salvage be separated from capital recovery within the depreciation accrual.

Q. Have you accepted any of Mr. Seelye's proposals?

A. Yes, I have accepted several of Mr. Seelye's proposals. First, I accepted almost all of his recommendations to retain the existing rates for several accounts. I have accepted several of his judgmental adjustments, and I have also accepted most of Mr. Seelye's proposed lives and Iowa curves.

Q. Was your decision to accept these parameters passive or did you conduct analyses to arrive at your decision?

A. My decision to accept these parameters was not passive; I conducted substantial analyses as will be discussed in several later sections of my testimony. Where I have accepted the Company's proposals it was based on my own independent analyses.

Depreciation Concepts

Q. What is depreciation expense?

A. In summary, depreciation expense is a charge to operating expense to reflect the recovery of a company's previously expended capital. Public utility depreciation expense is typically straight-line over service life which results in an equal share of the cost of assets being assigned to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant [and equipment] is in service.[6] Annual depreciation expense is a cost included in a public utility's revenue requirement.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense is calculated by applying a depreciation rate to plant balances. The resulting expense (also called accrual) is charged, just as any other expense, to the revenue requirement and from there it is charged to the utility's customers.

Q. Is it true that depreciation is a non-cash expense?

A. Yes. Depreciation is a non-cash expense in contrast to payroll expense, for example, which involves the current outlay of cash. That is, depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation

[6] Public Utility Depreciation Practices, August, 1996. National Association of Regulatory Utility Commissioners ("NARUC Manual"), p. 321.

expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and simultaneously recorded on the balance sheet in the accumulated depreciation account, which is shown as an offset to plant in service.

Q. What is the accumulated depreciation account?

A. Accumulated depreciation (sometimes called reserve) is, in essence, a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. It can be considered a measure of the depreciation recovered from ratepayers.

Q. Does the fact that depreciation is a non-cash expense render it any less legitimate than any other expense?

A. Depreciation is a legitimate expense. However, since it is based on a substantial amount of judgment and complex analytical procedures, the measurement of depreciation and the calculation of the expense warrant careful consideration.

Q. What is the objective of depreciation expense?

A. For public utilities, the objective of depreciation is straight-line capital recovery. As stated above, this is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances.

Q. How does Mr. Seelye determine this Company's annual depreciation rates?

A. Mr. Seelye's depreciation rates are founded upon three fundamental parameters: a service life, a dispersion pattern and a net salvage ratio. He used the remaining life technique to compute his proposed rates.

Q. Would you please explain how the rates were calculated?

A. Yes. In order to understand remaining-life depreciation, it is useful to first address whole-life depreciation.

Q. Please explain the whole-life technique.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 30-year average service life and zero ("0") percent net salvage.

<u>Table 1</u>

Straight-Line Whole-Life Depreciation Rate
<u>Assuming 30-Year Life and 0% Net Salvage</u>

$$\frac{100\%-(0\%)}{30\text{ yrs.}} = 3.3\%$$

Each year the 3.3 percent depreciation rate would be applied to plant in service to produce an annual depreciation expense.

Q. Please explain the remaining-life technique.

A. The remaining-life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation and the denominator becomes the remaining life rather that the whole life of the asset.

If the hypothetical 30-year asset is 10 years old, its remaining life would be 20 years (30 – 10 = 20). The accumulated depreciation account would be 33 percent of the original cost because the 3.3 percent depreciation rate from Table 1 would have been applied for ten years (10 x 3.3% = 33%). The remaining life depreciation rate would then be calculated as follows:

Table 2

Straight-Line Remaining Depreciation Life Rate
Assuming 30-year Life, 20-year Remaining Life
And 0% Net Salvage

$$\frac{100\% - (0\%) - 33\%}{20 \text{ years}} = 3.3\%$$

Q. Please explain why the whole-life depreciation rate in Table 1 and the remaining life depreciation rate in Table 2 are both 3.3 percent.

A. In these examples the remaining life depreciation rate and the whole-life depreciation rates are the same (3.3 percent), because I have assumed that the accumulated depreciation account is in balance. In other words, exactly the right amount of depreciation (33 percent) has been collected in the past, based on a continuation of the fundamental parameters, i.e., the 30-year service life and the zero percent net salvage ratio.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage.

Q. Why have you included this discussion about whole-life versus remaining life depreciation?

A. Mr. Seelye states at page 2 of his Depreciation Study that his "depreciation rates were calculated using the average service life depreciation procedure, the straight-line method, and the <u>remaining life basis</u>."[7] He then goes on to describe how he developed the remaining lives, remaining life accruals and depreciation rates.

<u>**Storage & Processing Depreciation Rates**</u>

Q. Do you disagree with Mr. Seelye's explanation of the remaining life technique?

A. I do not disagree with Mr. Seelye's explanation. I do, however, disagree with Mr. Seelye's application of the remaining life technique to the plant accounts in the Storage & Processing function.

Q. Did Mr. Seelye estimate remaining lives for the accounts in this plant function?

A. Yes, Mr. Seelye estimated remaining lives for each account in this function.[8]

Q. Why do you disagree with Mr. Seelye's application of the remaining life technique to the plant accounts in the Storage & Processing function?

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[7] Seelye Exhibit 7, page 2.
[8] Id., pages 7-8.

A. I disagree because Mr. Seelye used the whole-life technique rather than the remaining life technique to calculate depreciation rates. In other words, he used remaining lives to calculate whole-life rates. This overstated the resulting depreciation rates because Mr. Seelye did not incorporate the accumulated depreciation into his calculation for these accounts. This is a fundamental error. I have recalculated the remaining life depreciation rates in the Storage & Processing function reflecting the accumulated depreciation as well as Mr. Seelye's estimated remaining lives.

Q. Is there anything unique about public utility depreciation?

A. Yes. There are three unique factors driving public utility depreciation rates. First, public utility depreciation is based on a "group life" as opposed to the lives of individual assets. Second, the cost of removing or disposing of an asset that is retired from service is charged to the accumulated depreciation reserve, as opposed to being recognized as an operating cost in the year incurred. Third, the original cost of a retired asset is also recorded in the accumulated depreciation reserve, as opposed to being written off in the year of the asset's retirement/disposal. Each of these factors affects the depreciation rates that are ultimately determined for the group of assets that are recorded in plant accounts designated by the FERC Uniform System of Accounts ("USOA").

<u>Group Depreciation</u>

Q. Please explain the concept of group life depreciation.

A. Depreciation expense is one of the primary cost drivers of public utility revenue requirement calculations because these companies are capital intensive. An excessive depreciation rate can unreasonably increase the utility's revenue requirement and resulting service rates, thereby unnecessarily charging millions of dollars to a utility's customers.

Given the capital intensity of the industry, it is impossible to track and depreciate every <u>single</u> asset that a utility owns. Utilities own millions of assets, represented by millions of dollars of investment. Public utility depreciation is, therefore, based on a group concept which relies on averages of the service lives and remaining lives of the assets within a specific group.

These factors are necessarily estimates of the average service lives and average remaining lives of groups of assets. These estimates are in turn based on complex analytical procedures, which involve not only the age of existing and retired assets, but also retirement dispersion patterns called "Iowa curves."

I will discuss all of these in more detail later in my testimony. The important point to remember is that service life, average age and Iowa curves are all used in the estimation of an average service life and average remaining life of a group of assets and are ultimately used to calculate the depreciation rate for that group of assets.

Q. Would you please relate these fundamentals to the issues in this proceeding?

A. Yes. In depreciation analyses it is axiomatic that the shorter the life, the higher the resulting depreciation rate. Three of Mr. Seelye's proposed depreciation rates are too high because they are based on lives which are too short. The following table shows the impact of a shorter life.

Table 3

Impact of Lives on Depreciation Rates

30 year life = 100%-(0%)/30 = 3.3%

10 year life = 100%-(0%)/10 = 10.0%

The shorter the life, the higher the rate; if the life is too short, the resulting rate is obviously excessive.

Q. Which lives are too short?

A. Based on my analyses, the following three lives proposed by Mr. Seelye are too short.

Mr. Seelye's Understated Lives

369	Meas. and Reg. Station Equipment	39 S3
376	Distribution Mains	37 R3
382	Meter and Reg. Installation	40 S1

Q. Why do you believe these lives are too short?

A. Typically, service life estimates start with actuarial or semi-actuarial studies of historical plant information. These studies provide a statistical expression of the average service lives and retirement patterns (dispersion) that have actually been experienced in the past. Mr. Seelye used the semi-actuarial Simulated Plant Record Balances ("SPR") approach to study plant history, based on the type of available data.

Q. What is the Simulated Plant Record Balances method?

A. The SPR method, commonly referred to as a semi-actuarial method, is a statistical technique that is used when aged retirement and exposure data is not available. The SPR Balances method requires a less refined record of annual plant additions, balances and retirements than a true actuarial rate method such as the retirement-rate method. Although the SPR Balances method uses the same Iowa Curves as the retirement-rate method, they are applied differently to obtain a best-fit result, using least-squares analyses.

Q. What is an Iowa curve?

A. An Iowa curve is a surrogate or standardized life table based on a specific pattern of retirements around an average service life. The Iowa curves were devised over 60 years ago at what is now Iowa State University. They provide a set of standard patterns of retirement dispersion. Retirement dispersion merely recognizes that accounts are comprised of individual assets or units having different lives. Retirement dispersion is the scattering of retirements by age for the individual assets around the average service life for the entire group assets. If one thinks in terms of a "bell shaped" curve, dispersion represents the scattering of events around the average.

There are left-skewed, symmetrical and right-skewed curves known respectively, as the "L curves," "S curves" and "R curves."[9] A number identifies

[9] There is also a set of Origin Modal ("O") curves which are essentially negative exponential curves.

the range of dispersion. A low number represents a wide pattern and high number a narrow pattern. The combination of one letter and one number defines a dispersion pattern. The combination of an average service life with an Iowa curve provides a survivor curve depicting how a group of assets will survive, or conversely be retired, over the average service life.

Q. **Can you provide an example of an Iowa curve?**

A. Yes. The following table contains a 5 S0 and 10 S0 life and curve. I have included two combinations to demonstrate that these curves can be calculated with various alternative life assumptions. The percent surviving represents the amount surviving at each age interval shown in the first column. Notice that the 5 S0 life and curve sums to the 5 year average service life which would be used in the depreciation calculations and the 10 S0 life and curve sums to a 10 year average service life.

Table 4

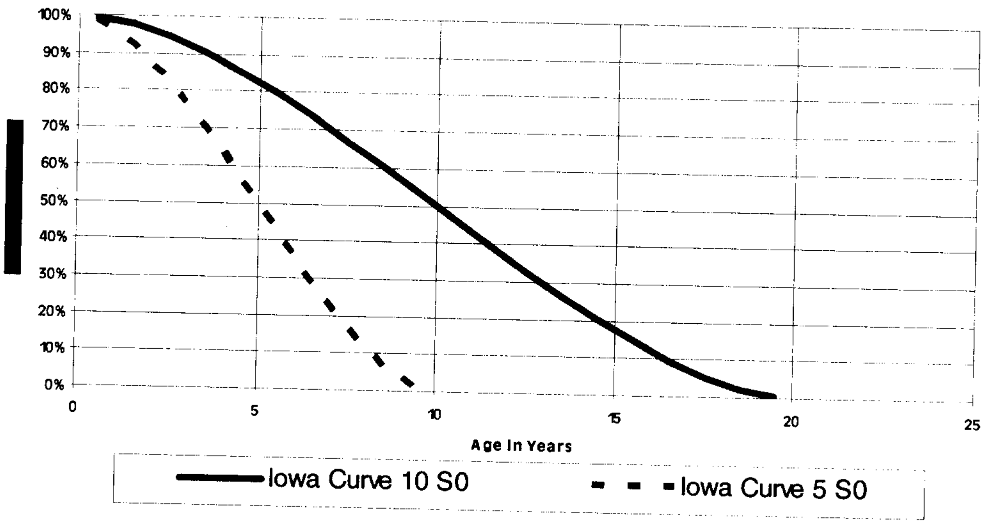
Age	Survivor Curves 5 S0 Percent Surviving	10 S0 Percent Surviving
0.5	0.99	1.00
1.5	0.92	0.98
2.5	0.83	0.94
3.5	0.70	0.90
4.5	0.57	0.85
5.5	0.43	0.80
6.5	0.30	0.74
7.5	0.17	0.67
8.5	0.08	0.60
9.5	0.01	0.53
10.5		0.47
11.5		0.40
12.5		0.33
13.5		0.26
14.5		0.20
15.5		0.15
16.5		0.10
17.5		0.06
18.5		0.02
19.5		0.00
Total	**5.00**	**10.00**

Q. Why do you call tables of numbers, such as the ones above, curves?

A. Because when they are plotted on charts with the x-axis representing "age" and the y-axis representing "percent surviving" they appear as curves as shown below:

Table 5

Example of Same Curve With Different Lives



Life Analyses Approach

Q. What was your approach to analyzing Mr. Seelye's proposed lives and curves?

A. I intended to begin by reviewing Mr. Seelye's SPR studies. However, they were not provided in his study or in the various responses to my data requests.

Q. What did you do in lieu of reviewing Mr. Seelye's SPR studies?

A. I reviewed the Company's responses to data requests to see if I could glean any additional information. Also, I performed Geometric Mean Turnover studies ("GMTs") for those accounts for which data was available.

Q. What is the Geometric Mean Turnover method?

A. The Geometric Mean Turnover Method ("GMT") is one of the turnover methods of life analyses. Turnover methods provide an indication of the average life of the property.[10] Turnover methods may be used to study retirements in relation to plant balances irrespective of the age of the property retired.[11] Turnover methods use annual additions, retirements and plant balances. The GMT method is based on ratios of annual additions and retirements to plant balances and is useful in detecting trends. The life estimate is the reciprocal of the geometric mean of the additions and retirements ratios averaged over a period of years.[12] The GMT method is very useful in detecting service lives and service life trends. Turnover methods assume a uniform retirement dispersion, in other words the results of turnover analyses focus on the fundamental life statistic, unencumbered by 31 possible Iowa curve retirement dispersion estimates.

Q. What did you conclude from your GMT analyses?

A. In many instances Mr. Seelye stated that there was insufficient data for an account to conduct SPR analyses. Since the GMT method uses the same data, it is quite simple to view the analyses to determine whether there is sufficient data. My GMT analyses tended to corroborate Mr. Seelye's findings concerning a lack of sufficient data for several accounts.

Q. What other conclusions did you reach?

A. In several cases my GMT studies also corroborated Mr. Seelye's recommendations based on his SPR studies.

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[10] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Depreciation Manual"), p. 81.
[11] Id.
[12] Id., p. 91.

Q. How did you determine that you disagree with three of Mr. Seelye's recommendations?

A. Although my GMT studies corroborated certain of Mr. Seelye's results, they also lead me to question his proposals for several other accounts.

Q. How did you approach those accounts?

A. I conducted my own SPR studies.

Q. What were the results of these additional studies?

A. Again, I was able to eliminate certain disagreements. On the other hand, I was not able to eliminate my disagreements for the three accounts at issue.

Q. Would you please describe your individual disagreements?

A. Yes.

Account 369-Measuring and Regulating Station Equipment

Mr. Seelye proposes a 39 S3 life and curve for this account. My GMT analysis, which is attached as Exhibit___(MJM-1), indicates that while lives move up and down they are fairly consistent around a 44 year average. My SPR analysis for account 369 is also included in Exhibit___(MJM-1). It reveals that the best fit for the account is a 45 R2.5 which is relatively consistent with the GMT result whereas Mr. Seelye's 39 S3 ranked 20 on the list. I have no reason to reject the best fit for this account and therefore on that basis conclude that Mr. Seelye's 39-year life is understated. The data supports a 45 R2.5 life and curve, which is what I recommend.

Account 376 – Distribution Mains

Mr. Seelye states that his SPR supports a 37 R3 life and curve. However, he rejects those results and retains the current 2.50 percent depreciation rate because the use of a 37-year life produces a higher rate. Exhibit___(MJM-1) includes my GMT study which demonstrates that there is more than sufficient data for a statistical analysis. The overall GMT supports a 52-year life. The best fit from my SPR for this account (also included in the Exhibit) supports a 77 R0.5 year life and curve. However, given that distribution services are included in the data, I recommend a 52 S0 life and curve which is ranked number 7 in the SPR study. This is corroborated by the GMT. Mr. Seelye's 37-year life is understated, and in my opinion, is merely used to avoid a warranted reduction to the current depreciation rate for this account.

Account 382 – Meter and Reg. Installation

Mr. Seelye stated that he proposes a 54 S1 life and curve for this account. However, examination of his data indicates that he actually used a 40 S1. My GMT study supports a 53-year life which tends to corroborate Mr. Seelye's original results.[13] Although the SPR best fit is actually 63 S0 years, I recommend 44 R2.5 which is the second best fit.[14] This provides some relationship to the 40-year life being used for Meters.

Q. Is there any other reason that Mr. Seelye's depreciation rates are excessive?

[13] See Exhibit___(MJM-1).

A. Several of Mr. Seelye's proposed depreciation rates contain negative net salvage allowances which collect too much for future cost of removal and thus are far too negative. The result is excessive depreciation rates. Overall, Delta's experience has been positive net salvage and Mr. Seelye has recognized that fact in a positive ratio for account 392 Transportation Equipment. However, he subtracted the Transportation Equipment depreciation expense from the overall depreciation claim, thus eliminating the positive net salvage. After the elimination, Mr. Seelye has incorporated about $45 thousand of negative net salvage into his accruals versus the $11 thousand Delta has experienced on average during the past five years.[15] I have eliminated Mr. Seelye's net salvage factors for all but Transportation Equipment and replaced them with an addition of $11,274 to the annual accrual to account for negative net salvage. I have left Mr. Seelye's Transportation rate as is because it is subtracted from the overall result in any case.

Q. Do you have any strong objection to Mr. Seelye's $45 thousand amount?

A. No. In my opinion it is immaterial. I have replaced it primarily because Mr. Seelye did not produce any studies to support it. The recommended $11,274 is at least based on actual data.

Q. Have you summarized your results?

A. Yes, Exhibit___(MJM-2) summarizes my results. The following table compares my results to Mr. Seelye's.

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[14] Id.

In the Matter of:

AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	)))	**CASE NO: 2004-00067**

AFFIDAVIT

Comes the affiant, Michael Majoros, Jr., and being duly sworn states that the foregoing testimony and attached schedules were prepared by him or under his direction and supervision and are, to the best of his information and belief, true and correct.

State/Commonwealth of District of Columbia
County of ~~Washington~~ ; ss.

Subscribed and sworn to before me by the Affiant Michael Majoros, Jr. this the 1st day of July, 2004.

Angel L. Finch
Notary Public, State at Large
My Commission Expires: 3-14-06

Table 6

	Seelye	Majoros
Depreciation Expense	$ 4,045,073	$ 3,297,329
Per Books	4,190,504	4,190,504
Decrease	($ 145,431)	($ 893,175)

Q. Does this complete your testimony?

A. Yes, it does.

[15] See Exhibit___(MJM-2).

Delta Natural Gas Company, Inc.

Exhibit___(MJM-1)

Delta Natural Gas Company, Inc.

369 - Meas. & Reg. Station Equipment

SPR Results
Delta Natural Gas Company
Account: 369 - Measuring & Regulating Station Equipment

Curve	Life	Sum of Squared Differences	Index of Variation
BAND	**1951 - 2002**		
R2.5	45	1.24E+09	12
R2	51	1.25E+09	12
R1.5	62	1.28E+09	12
R1	76	1.32E+09	13
R0.5	99	1.33E+09	13
S-0.5	88	1.36E+09	13
L0.5	76	1.43E+09	13
L1	63	1.45E+09	13
L1.5	55	1.46E+09	13
R3	41	1.46E+09	13
L0	94	1.48E+09	13
S0.5	55	1.49E+09	13
S0	64	1.51E+09	14
S1	49	1.59E+09	14
S1.5	45	1.60E+09	14
L2	49	1.64E+09	14
S2	42	1.81E+09	15
L3	42	2.00E+09	16
R4	38	2.33E+09	17
S3	39	2.35E+09	17
L4	38	2.65E+09	18
S4	37	3.24E+09	20
L5	36	3.64E+09	21
R5	36	3.70E+09	21
O1	100	3.77E+09	21
S5	36	4.10E+09	22
S6	35	4.98E+09	25
SQ	35	5.80E+09	26
O2	100	7.82E+09	31
O3	100	4.38E+10	73
O4	100	1.25E+11	123

Minimum Equipment Life Expectancy: 11
Maximum Equipment Life Expectancy: 100
Life Expectancy Increment: 1
Begin Year: 1951
End Year: 2002
Year Fit Increment: 0

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

Account 369 - Meas. & Reg. Station Equip. - Transmission

Year	BOY Plant Balance a	Avg. Plant Balance b=(a+(a+1))/2	Single Year Additions c	Single Year Retirements d	Addition Ratio e = c/b	Retirement Ratio f = d/b	Geometric Mean Life Estimate g = 1/sqrt(e*f)	3 Year Band h	3 Year Band: Avg. Plant Balance i	3 Year Band: Additions j	3 Year Band: Retirements k	3 Year Band: Addition Ratio l = j/i	3 Year Band: Retirement Ratio m = k/i	3 Year Band: Geometric Mean Life Estimate n = 1/sqrt(l*m)
1951	-	302	604	-	2.00000	-	-	1951-53	1,510	604	-	0.40000	-	-
1952	604	604	-	-	-	-	-	1952-54	1,812	-	-	-	-	-
1953	604	604	-	-	-	-	-	1953-55	3,223	2,821	-	0.87541	-	-
1954	604	604	-	-	-	-	-	1954-56	7,702	6,138	-	0.79694	-	-
1955	604	2,015	2,821	-	1.40035	-	-	1955-57	14,705	7,868	-	0.53506	-	-
1956	3,425	5,084	3,317	-	0.65250	-	-	1956-58	23,274	9,269	-	0.39826	-	-
1957	6,742	7,607	1,730	-	0.22742	-	-	1957-59	36,704	17,592	-	0.47929	-	-
1958	8,472	10,583	4,222	-	0.39894	-	-	1958-60	71,649	52,298	-	0.72992	-	-
1959	12,694	18,514	11,640	-	0.62871	-	-	1959-61	123,011	50,426	-	0.40993	-	-
1960	24,334	42,552	36,436	-	0.85627	-	-	1960-62	167,509	38,929	360	0.23240	0.00215	44.75
1961	60,770	61,945	2,350	-	0.03794	-	-	1961-63	188,494	4,083	681	0.02166	0.00361	113.04
1962	63,120	63,012	143	360	0.00227	0.00571	277.72	1962-64	191,713	4,202	1,167	0.02192	0.00609	86.57
1963	62,903	63,538	1,590	321	0.02502	0.00505	88.94	1963-65	198,028	15,255	5,660	0.07703	0.02858	21.31
1964	64,172	65,164	2,469	486	0.03789	0.00746	59.49	1964-66	213,267	26,265	5,382	0.12316	0.02524	17.94
1965	66,155	69,327	11,196	4,853	0.16150	0.07000	9.41	1965-67	235,960	29,850	5,346	0.12650	0.02266	18.68
1966	72,498	78,777	12,600	43	0.15995	0.00055	107.02	1966-68	260,222	24,597	577	0.09452	0.00222	69.07
1967	85,055	87,857	6,054	450	0.06891	0.00512	53.23	1967-69	286,727	30,943	1,954	0.10792	0.00681	36.87
1968	90,659	93,589	5,943	84	0.06350	0.00090	132.46	1968-70	315,142	29,346	1,504	0.09312	0.00477	47.44
1969	96,518	105,281	18,946	1,420	0.17996	0.01349	20.30	1969-71	351,400	46,093	1,420	0.13117	0.00404	43.43
1970	114,044	116,273	4,457	-	0.03833	-	-	1970-72	388,234	28,995	-	0.07468	-	-
1971	118,501	129,846	22,690	-	0.17475	-	-	1971-73	420,502	35,541	-	0.08452	-	-
1972	141,191	142,115	1,848	-	0.01300	-	-	1972-74	455,253	34,301	339	0.07534	0.00074	133.51
1973	143,039	148,541	11,003	-	0.07407	-	-	1973-75	521,744	101,430	2,410	0.19441	0.00462	33.37
1974	154,042	164,598	21,450	339	0.13032	0.00206	61.04	1974-76	627,939	116,399	3,030	0.18537	0.00483	33.44
1975	175,153	208,606	68,977	2,071	0.33066	0.00993	17.45	1975-77	733,351	100,809	3,353	0.13746	0.00457	39.89
1976	242,059	254,735	25,972	620	0.10196	0.00243	63.48	1976-78	797,897	33,957	2,322	0.04256	0.00291	89.86
1977	267,411	270,010	5,860	662	0.02170	0.00245	137.09	1977-79	822,830	19,934	1,702	0.02423	0.00207	141.26
1978	272,609	273,152	2,125	1,040	0.00778	0.00381	183.74	1978-80	840,733	18,613	1,040	0.02214	0.00124	191.09
1979	273,694	279,669	11,949	-	0.04273	-	-	1979-81	858,811	18,584	-	0.02164	-	-
1980	285,643	287,913	4,539	-	0.01577	-	-	1980-82	872,480	8,754	-	0.01003	-	-
1981	290,182	291,230	2,096	-	0.00720	-	-	1981-83	884,580	15,446	-	0.01746	-	-
1982	292,278	293,338	2,119	-	0.00722	-	-	1982-84	944,638	107,020	2,350	0.11329	0.00249	59.57
1983	294,397	300,013	11,231	-	0.03744	-	-	1983-85	1,067,756	145,570	4,004	0.13633	0.00375	44.23
1984	305,628	351,288	93,670	2,350	0.26665	0.00669	23.68	1984-86	1,205,785	138,495	4,004	0.11486	0.00332	51.20
1985	396,948	416,456	40,669	1,654	0.09766	0.00397	50.78	1985-87	1,295,391	46,376	1,654	0.03580	0.00128	147.91
1986	435,963	438,041	4,156	-	0.00949	-	-	1986-88	1,327,365	20,435	1,210	0.01540	0.00091	266.94
1987	440,119	440,895	1,551	-	0.00352	-	-	1987-89	1,385,790	104,744	7,119	0.07558	0.00514	50.75
1988	441,670	448,429	14,728	1,210	0.03284	0.00270	106.23	1988-90	1,500,649	139,213	7,119	0.09277	0.00474	47.67
1989	455,188	496,466	88,465	5,909	0.17819	0.01190	21.71	1989-91	1,645,882	164,280	5,909	0.09981	0.00359	52.83
1990	537,744	555,754	36,020	-	0.06481	-	-	1990-92	1,784,570	119,005	-	0.06669	-	-
1991	573,764	593,662	39,795	-	0.06703	-	-	1991-93	1,905,756	127,123	3,756	0.06670	0.00197	87.22
1992	613,559	635,154	43,190	-	0.06800	-	-	1992-94	2,027,729	124,336	3,756	0.06132	0.00185	93.83
1993	656,749	676,940	44,138	3,756	0.06520	0.00555	52.58	1993-95	2,120,586	92,201	27,068	0.04348	0.01276	42.45
1994	697,131	715,635	37,008	-	0.05171	-	-	1994-96	2,175,346	67,699	23,312	0.03112	0.01072	54.76
1995	734,139	728,011	11,055	23,312	0.01519	0.03202	45.35	1995-97	2,270,705	169,643	23,312	0.07471	0.01027	36.11
1996	721,882	731,700	19,636	-	0.02684	-	-	1996-98	2,522,335	356,929	-	0.14151	-	-
1997	741,518	810,994	138,952	-	0.17134	-	-							
1998	880,470	979,641	198,341	-	0.20246	-	-							

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

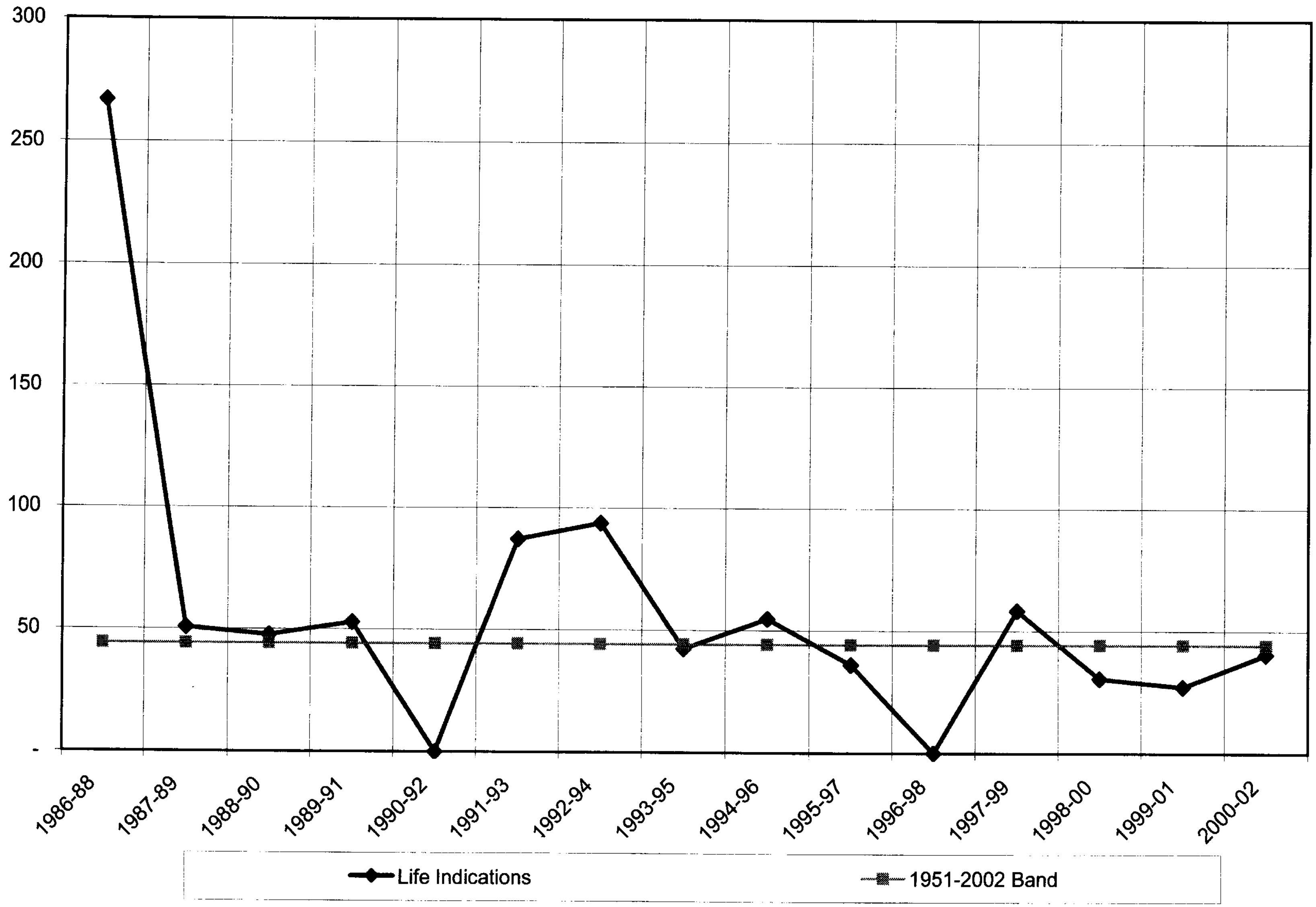
Account 369 - Meas. & Reg. Station Equip. - Transmission

								3 Year Band						
Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	Avg. Plant Balance	Additions	Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1999	1,078,811	1,340,246	526,196	3,327	0.39261	0.00248	32.03	1997-99	3,130,880	863,489	3,327	0.27580	0.00106	58.41
2000	1,601,680	1,686,735	185,729	15,619	0.11011	0.00926	31.32	1998-00	4,006,621	910,266	18,946	0.22719	0.00473	30.51
2001	1,771,790	1,803,674	84,508	20,741	0.04685	0.01150	43.08	1999-01	4,830,654	796,433	39,687	0.16487	0.00822	27.17
2002	1,835,557	1,926,486	184,938	3,080	0.09600	0.00160	80.72	2000-02	5,416,895	455,175	39,440	0.08403	0.00728	40.43
1951-2002	18,704,486	19,713,194	2,111,122	93,707	0.10709	0.00475	44.32							

Data Source: Response to PSC-2-17.

Company: Delta Natural Gas Company
Account: 369
Category: Meas. & Reg. Station. Equip. - Trans.

Geometric Mean Rolling Band Analysis
Life Indications



Delta Natural Gas Company

369 - Measuring & Regulating Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **45 R2.5**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	184,198	45.00	44.53	4,093	182,259
2001	1.5	84,059	45.00	43.58	1,868	81,415
2000	2.5	184,475	45.00	42.65	4,099	174,828
1999	3.5	521,815	45.00	41.71	11,596	483,707
1998	4.5	196,349	45.00	40.79	4,363	177,958
1997	5.5	137,295	45.00	39.86	3,051	121,619
1996	6.5	19,361	45.00	38.94	430	16,756
1995	7.5	10,876	45.00	38.03	242	9,192
1994	8.5	36,317	45.00	37.13	807	29,962
1993	9.5	43,196	45.00	36.22	960	34,773
1992	10.5	42,143	45.00	35.33	937	33,088
1991	11.5	38,704	45.00	34.44	860	29,626
1990	12.5	34,909	45.00	33.56	776	26,038
1989	13.5	85,407	45.00	32.69	1,898	62,048
1988	14.5	14,159	45.00	31.83	315	10,015
1987	15.5	1,484	45.00	30.97	33	1,022
1986	16.5	3,958	45.00	30.12	88	2,649
1985	17.5	38,519	45.00	29.28	856	25,066
1984	18.5	88,199	45.00	28.45	1,960	55,767
1983	19.5	10,508	45.00	27.63	234	6,452
1982	20.5	1,969	45.00	26.82	44	1,173
1981	21.5	1,933	45.00	26.02	43	1,118
1980	22.5	4,152	45.00	25.22	92	2,328
1979	23.5	10,836	45.00	24.44	241	5,886
1978	24.5	1,909	45.00	23.67	42	1,004
1977	25.5	5,210	45.00	22.91	116	2,652
1976	26.5	22,839	45.00	22.16	508	11,246
1975	27.5	59,936	45.00	21.42	1,332	28,526
1974	28.5	18,399	45.00	20.69	409	8,459
1973	29.5	9,307	45.00	19.97	207	4,131
1972	30.5	1,540	45.00	19.27	34	659
1971	31.5	18,599	45.00	18.58	413	7,679
1970	32.5	3,589	45.00	17.90	80	1,428
1969	33.5	14,969	45.00	17.24	333	5,734
1968	34.5	4,599	45.00	16.59	102	1,695
1967	35.5	4,582	45.00	15.95	102	1,624

Delta Natural Gas Company

369 - Measuring & Regulating Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **45 R2.5**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	36.5	9,307	45.00	15.33	207	3,171
1965	37.5	8,055	45.00	14.73	179	2,636
1964	38.5	1,726	45.00	14.14	38	542
1963	39.5	1,078	45.00	13.57	24	325
1962	40.5	94	45.00	13.01	2	27
1961	41.5	1,485	45.00	12.48	33	412
1960	42.5	22,132	45.00	11.96	492	5,884
1959	43.5	6,773	45.00	11.47	151	1,726
1958	44.5	2,345	45.00	10.99	52	573
1957	45.5	914	45.00	10.53	20	214
1956	46.5	1,659	45.00	10.09	37	372
1955	47.5	1,331	45.00	9.67	30	286
1954	48.5	-	45.00	9.27	-	-
1953	49.5	-	45.00	8.89	-	-
1952	50.5	-	45.00	8.52	-	-
1951	51.5	215	45.00	8.18	5	39
		2,017,415			44,831	1,665,790

AVERAGE SERVICE LIFE	45.00
AVERAGE REMAINING LIFE	37.16

Delta Natural Gas Company, Inc.

376 - Distribution Mains

SPR Results
Delta Natural Gas Company
Account: 376 - Distribution Mains

Curve	Life	Sum of Squared Differences	Index of Variation
BAND	**1940 - 2002**		
R0.5	77	2.94E+12	18
R1	60	3.22E+12	19
S-0.5	70	3.25E+12	19
L0	75	3.58E+12	20
R1.5	50	3.66E+12	20
L0.5	62	3.93E+12	21
S0	52	4.26E+12	22
R2	43	4.55E+12	22
L1	52	4.62E+12	22
S0.5	46	4.77E+12	23
L1.5	46	5.20E+12	24
R2.5	38	5.31E+12	24
S1	41	5.64E+12	25
L2	41	6.14E+12	26
S1.5	38	6.16E+12	26
R3	35	6.31E+12	26
O1	80	6.65E+12	27
S2	35	6.94E+12	27
L3	35	7.50E+12	29
R4	32	7.74E+12	29
S3	33	8.00E+12	30
L4	32	8.90E+12	31
S4	31	9.47E+12	32
R5	31	1.04E+13	34
L5	31	1.05E+13	34
S5	31	1.18E+13	36
S6	31	1.43E+13	39
O2	80	1.47E+13	40
SQ	31	1.94E+13	46
O3	80	9.06E+13	99
O4	80	2.63E+14	169

Minimum Equipment Life Expectancy: 10
Maximum Equipment Life Expectancy: 80
Life Expectancy Increment: 1
Begin Year: 1940
End Year: 2002
Year Fit Increment: 0

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

Account 376 - Mains - Distribution

Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	3 Year Band: Avg. Plant Balance	3 Year Band: Additions	3 Year Band: Retirements	3 Year Band: Addition Ratio	3 Year Band: Retirement Ratio	3 Year Band: Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1940		29,481	58,962	-	2.00000	-	-							
1941	58,962	58,962	-	-	-	-	-							
1942	58,962	58,962	-	-	-	-	-	1940-42	147,405	58,962	-	0.40000	-	-
1943	58,962	58,962	-	-	-	-	-	1941-43	176,886	-	-	-	-	-
1944	58,962	58,962	-	-	-	-	-	1942-44	176,886	-	-	-	-	-
1945	58,962	58,962	-	-	-	-	-	1943-45	176,886	-	-	-	-	-
1946	58,962	58,962	-	-	-	-	-	1944-46	176,886	-	-	-	-	-
1947	58,962	96,845	75,766	-	0.78234	-	-	1945-47	214,769	75,766	-	0.35278	-	-
1948	134,728	168,661	67,865	-	0.40238	-	-	1946-48	324,468	143,631	-	0.44267	-	-
1949	202,593	233,597	62,008	-	0.26545	-	-	1947-49	499,103	205,639	-	0.41202	-	-
1950	264,601	279,528	29,854	-	0.10680	-	-	1948-50	681,786	159,727	-	0.23428	-	-
1951	294,455	312,768	36,626	-	0.11710	-	-	1949-51	825,893	128,488	-	0.15557	-	-
1952	331,081	340,386	18,609	-	0.05467	-	-	1950-52	932,682	85,089	-	0.09123	-	-
1953	349,690	356,181	12,981	-	0.03645	-	-	1951-53	1,009,334	68,216	-	0.06759	-	-
1954	362,671	386,348	47,353	-	0.12257	-	-	1952-54	1,082,914	78,943	-	0.07290	-	-
1955	410,024	484,274	148,499	-	0.30664	-	-	1953-55	1,226,802	208,833	-	0.17023	-	-
1956	558,523	630,492	143,937	-	0.22829	-	-	1954-56	1,501,113	339,789	-	0.22636	-	-
1957	702,460	722,324	39,727	-	0.05500	-	-	1955-57	1,837,089	332,163	-	0.18081	-	-
1958	742,187	759,350	34,326	-	0.04520	-	-	1956-58	2,112,165	217,990	-	0.10321	-	-
1959	776,513	829,768	106,509	-	0.12836	-	-	1957-59	2,311,441	180,562	-	0.07812	-	-
1960	883,022	917,852	69,660	-	0.07589	-	-	1958-60	2,506,970	210,495	-	0.08396	-	-
1961	952,682	1,007,985	110,606	-	0.10973	-	-	1959-61	2,755,605	286,775	-	0.10407	-	-
1962	1,063,288	1,099,057	71,538	-	0.06509	-	-	1960-62	3,024,894	251,804	-	0.08324	-	-
1963	1,134,826	1,173,352	86,884	9,832	0.07405	0.00838	40.15	1961-63	3,280,394	269,028	9,832	0.08201	0.00300	63.78
1964	1,211,878	1,254,093	89,514	5,084	0.07138	0.00405	58.79	1962-64	3,526,502	247,936	14,916	0.07031	0.00423	57.99
1965	1,296,308	1,354,265	123,728	7,814	0.09136	0.00577	43.55	1963-65	3,781,710	300,126	22,730	0.07936	0.00601	45.79
1966	1,412,222	1,477,288	135,264	5,133	0.09156	0.00347	56.06	1964-66	4,085,646	348,506	18,031	0.08530	0.00441	51.54
1967	1,542,353	1,697,262	317,430	7,612	0.18702	0.00448	34.53	1965-67	4,528,815	576,422	20,559	0.12728	0.00454	41.60
1968	1,852,171	1,936,420	182,038	13,540	0.09401	0.00699	39.00	1966-68	5,110,970	634,732	26,285	0.12419	0.00514	39.57
1969	2,020,669	2,305,851	582,335	11,971	0.25255	0.00519	27.62	1967-69	5,939,533	1,081,803	33,123	0.18214	0.00558	31.38
1970	2,591,033	3,314,761	1,455,571	8,116	0.43912	0.00245	30.50	1968-70	7,557,032	2,219,944	33,627	0.29376	0.00445	27.66
1971	4,038,488	4,520,653	1,074,050	109,721	0.23759	0.02427	13.17	1969-71	10,141,264	3,111,956	129,808	0.30686	0.01280	15.96
1972	5,002,817	5,151,755	324,850	26,975	0.06306	0.00524	55.03	1970-72	12,987,168	2,854,471	144,812	0.21979	0.01115	20.20
1973	5,300,692	5,519,095	448,840	12,035	0.08132	0.00218	75.09	1971-73	15,191,502	1,847,740	148,731	0.12163	0.00979	28.98
1974	5,737,497	5,863,456	294,232	42,315	0.05018	0.00722	52.55	1972-74	16,534,305	1,067,922	81,325	0.06459	0.00492	56.11
1975	5,989,414	6,170,176	409,344	47,820	0.06634	0.00775	44.10	1973-75	17,552,726	1,152,416	102,170	0.06565	0.00582	51.15
1976	6,350,938	6,441,878	201,118	19,238	0.03122	0.00299	103.56	1974-76	18,475,510	904,694	109,373	0.04897	0.00592	58.73
1977	6,532,818	6,630,786	215,318	19,383	0.03247	0.00292	102.64	1975-77	19,242,840	825,780	86,441	0.04291	0.00449	72.02
1978	6,728,753	6,864,025	316,671	46,128	0.04613	0.00672	56.79	1976-78	19,936,688	733,107	84,749	0.03677	0.00425	79.98
1979	6,999,296	7,316,175	723,822	90,065	0.09893	0.01231	28.65	1977-79	20,810,985	1,255,811	155,576	0.06034	0.00748	47.08
1980	7,633,053	7,933,100	646,465	46,371	0.08149	0.00585	45.82	1978-80	22,113,299	1,686,958	182,564	0.07629	0.00826	39.85
1981	8,233,147	9,160,917	1,960,024	104,484	0.21396	0.01141	20.24	1979-81	24,410,192	3,330,311	240,920	0.13643	0.00987	27.25
1982	10,088,687	10,849,398	1,666,448	145,027	0.15360	0.01337	22.07	1980-82	27,943,415	4,272,937	295,882	0.15291	0.01059	24.85
1983	11,610,108	12,339,237	1,579,871	121,613	0.12804	0.00986	28.15	1981-83	32,349,552	5,206,343	371,124	0.16094	0.01147	23.27
1984	13,068,366	13,722,070	1,436,971	129,563	0.10472	0.00944	31.80	1982-84	36,910,705	4,683,290	396,203	0.12688	0.01073	27.10
1985	14,375,774	15,081,623	1,581,605	169,907	0.10487	0.01127	29.09	1983-85	41,142,930	4,598,447	421,083	0.11177	0.01023	29.57
1986	15,787,472	16,592,699	1,813,432	202,979	0.10929	0.01223	27.35	1984-86	45,396,392	4,832,008	502,449	0.10644	0.01107	29.13
1987	17,397,925	18,296,501	1,928,903	131,752	0.10542	0.00720	36.29	1985-87	49,970,822	5,323,940	504,638	0.10654	0.01010	30.49

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

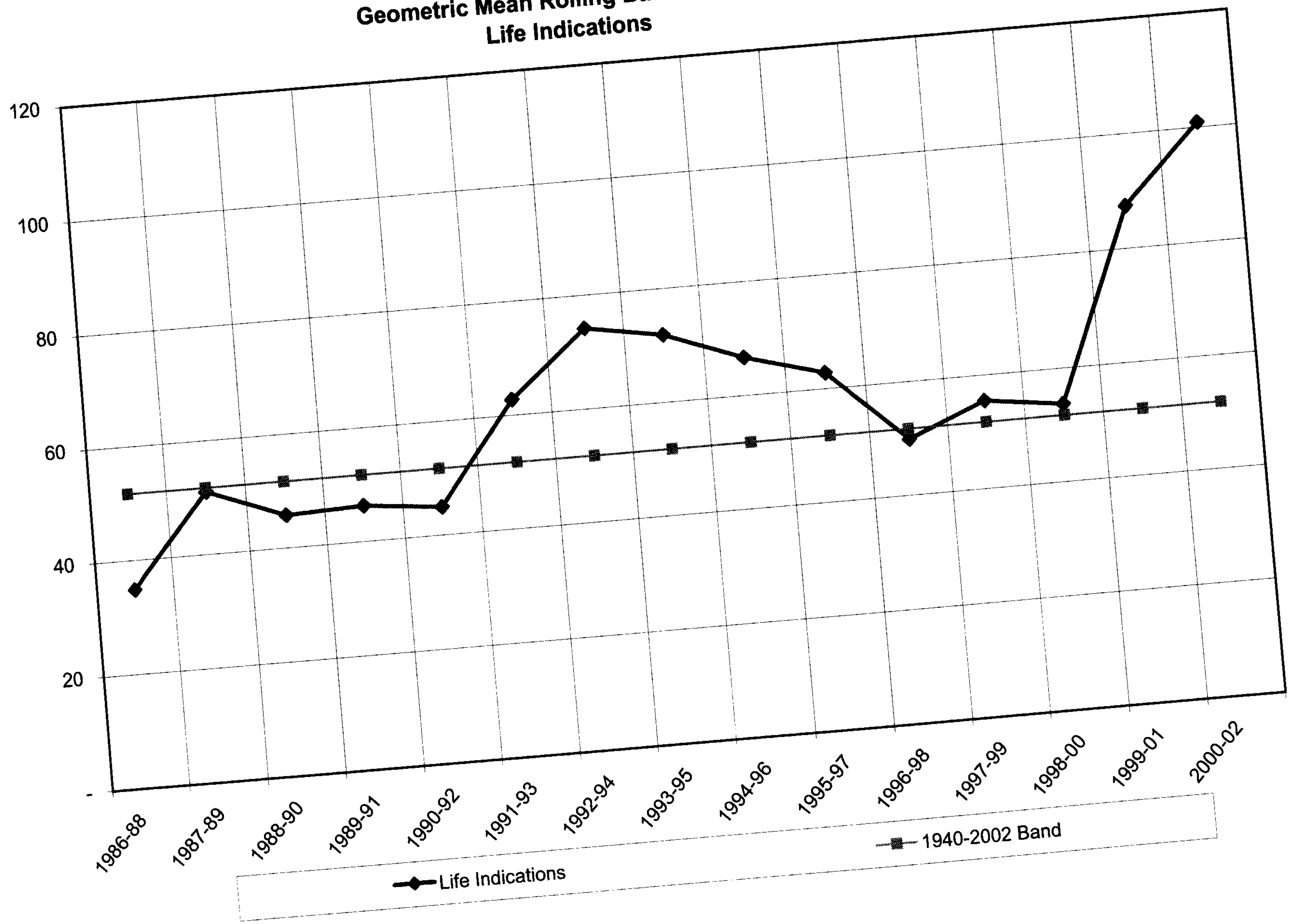
Account 376 - Mains - Distribution

Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	3 Year Band: Avg. Plant Balance	3 Year Band: Additions	3 Year Band: Retirements	3 Year Band: Addition Ratio	3 Year Band: Retirement Ratio	3 Year Band: Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1988	19,195,076	20,354,863	2,394,747	75,173	0.11765	0.00369	47.97	1986-88	55,244,062	6,137,082	409,904	0.11109	0.00742	34.83
1989	21,514,650	21,893,031	823,954	67,192	0.03764	0.00307	93.05	1987-89	60,544,395	5,147,604	274,117	0.08502	0.00453	50.97
1990	22,271,412	23,462,032	2,593,632	212,392	0.11055	0.00905	31.61	1988-90	65,709,926	5,812,333	354,757	0.08845	0.00540	45.76
1991	24,652,652	26,110,183	3,006,462	91,401	0.11515	0.00350	49.81	1989-91	71,465,246	6,424,048	370,985	0.08989	0.00519	46.29
1992	27,567,713	28,568,925	2,091,957	89,533	0.07322	0.00313	66.01	1990-92	78,141,140	7,692,051	393,326	0.09844	0.00503	44.92
1993	29,570,137	30,795,855	2,514,631	63,196	0.08165	0.00205	77.25	1991-93	85,474,962	7,613,050	244,130	0.08907	0.00286	62.70
1994	32,021,572	33,117,607	2,265,544	73,474	0.06841	0.00222	81.17	1992-94	92,482,387	6,872,132	226,203	0.07431	0.00245	74.18
1995	34,213,642	35,745,354	3,168,792	105,369	0.08865	0.00295	61.86	1993-95	99,658,815	7,948,967	242,039	0.07976	0.00243	71.85
1996	37,277,065	38,513,159	2,615,832	143,644	0.06792	0.00373	62.83	1994-96	107,376,120	8,050,168	322,487	0.07497	0.00300	66.64
1997	39,749,253	41,063,326	2,773,515	145,370	0.06754	0.00354	64.67	1995-97	115,321,838	8,558,139	394,383	0.07421	0.00342	62.77
1998	42,377,398	44,438,198	4,460,035	338,435	0.10036	0.00762	36.17	1996-98	124,014,683	9,849,382	627,449	0.07942	0.00506	49.89
1999	46,498,998	48,112,103	3,293,998	67,788	0.06847	0.00141	101.82	1997-99	133,613,627	10,527,548	551,593	0.07879	0.00413	55.45
2000	49,725,208	51,194,754	3,187,950	248,859	0.06227	0.00486	57.48	1998-00	143,745,055	10,941,983	655,082	0.07612	0.00456	53.69
2001	52,664,299	53,455,247	1,640,935	59,039	0.03070	0.00110	171.74	1999-01	152,762,104	8,122,883	375,686	0.05317	0.00246	87.45
2002	54,246,195	54,749,726	1,118,713	111,651	0.02043	0.00204	154.91	2000-02	159,399,727	5,947,598	419,549	0.03731	0.00263	100.91
1940-2002	705,923,227	733,549,856	58,680,251	3,426,994	0.07999	0.00467	51.73							

Data Source: Response to PSC-2-17.

Company: Delta Natural Gas Company
Account: 376
Category: Mains - Distribution

Geometric Mean Rolling Band Analysis
Life Indications



Delta Natural Gas Company

376 - Distribution Mains

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

52 S0

SURVIVOR CURVE..IOWA

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	1,136,612	52.00	51.51	21,858	1,125,860
2001	1.5	1,665,266	52.00	50.57	32,024	1,619,375
2000	2.5	3,228,965	52.00	49.66	62,095	3,083,909
1999	3.5	3,327,684	52.00	48.79	63,994	3,122,418
1998	4.5	4,491,155	52.00	47.95	86,368	4,141,210
1997	5.5	2,782,300	52.00	47.13	53,506	2,521,643
1996	6.5	2,612,781	52.00	46.33	50,246	2,327,925
1995	7.5	3,149,800	52.00	45.55	60,573	2,759,305
1994	8.5	2,239,974	52.00	44.79	43,076	1,929,587
1993	9.5	2,471,827	52.00	44.05	47,535	2,094,063
1992	10.5	2,043,468	52.00	43.33	39,297	1,702,659
1991	11.5	2,917,054	52.00	42.62	56,097	2,390,695
1990	12.5	2,498,490	52.00	41.92	48,048	2,014,198
1989	13.5	787,700	52.00	41.24	15,148	624,671
1988	14.5	2,271,004	52.00	40.57	43,673	1,771,700
1987	15.5	1,813,776	52.00	39.91	34,880	1,392,027
1986	16.5	1,690,078	52.00	39.26	32,502	1,276,048
1985	17.5	1,460,340	52.00	38.62	28,083	1,084,705
1984	18.5	1,313,937	52.00	38.00	25,268	960,119
1983	19.5	1,430,009	52.00	37.38	27,500	1,027,958
1982	20.5	1,492,519	52.00	36.77	28,702	1,055,436
1981	21.5	1,736,288	52.00	36.17	33,390	1,207,796
1980	22.5	566,185	52.00	35.58	10,888	387,411
1979	23.5	626,495	52.00	35.00	12,048	421,650
1978	24.5	270,762	52.00	34.42	5,207	179,232
1977	25.5	181,790	52.00	33.85	3,496	118,349
1976	26.5	167,599	52.00	33.29	3,223	107,300
1975	27.5	336,551	52.00	32.74	6,472	211,876
1974	28.5	238,568	52.00	32.19	4,588	147,674
1973	29.5	358,745	52.00	31.65	6,899	218,323
1972	30.5	255,835	52.00	31.11	4,920	153,056
1971	31.5	833,095	52.00	30.58	16,021	489,903
1970	32.5	1,111,482	52.00	30.05	21,375	642,382
1969	33.5	437,568	52.00	29.53	8,415	248,517
1968	34.5	134,536	52.00	29.02	2,587	75,078
1967	35.5	230,635	52.00	28.51	4,435	126,444

Delta Natural Gas Company

376 - Distribution Mains

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

52 S0

SURVIVOR CURVE..IOWA

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	36.5	96,573	52.00	28.00	1,857	52,007
1965	37.5	86,762	52.00	27.50	1,668	45,888
1964	38.5	61,620	52.00	27.01	1,185	32,003
1963	39.5	58,685	52.00	26.51	1,129	29,923
1962	40.5	47,387	52.00	26.03	911	23,718
1961	41.5	71,813	52.00	25.54	1,381	35,275
1960	42.5	44,308	52.00	25.06	852	21,355
1959	43.5	66,332	52.00	24.59	1,276	31,363
1958	44.5	20,920	52.00	24.11	402	9,701
1957	45.5	23,679	52.00	23.64	455	10,767
1956	46.5	83,855	52.00	23.18	1,613	37,379
1955	47.5	84,510	52.00	22.72	1,625	36,919
1954	48.5	26,308	52.00	22.26	506	11,261
1953	49.5	7,036	52.00	21.80	135	2,950
1952	50.5	9,834	52.00	21.35	189	4,037
1951	51.5	18,857	52.00	20.90	363	7,579
1950	52.5	14,965	52.00	20.45	288	5,886
1949	53.5	30,241	52.00	20.01	582	11,635
1948	54.5	32,176	52.00	19.57	619	12,107
1947	55.5	34,895	52.00	19.13	671	12,835
1946	56.5	-	52.00	18.69	-	-
1945	57.5	-	52.00	18.26	-	-
1944	58.5	-	52.00	17.83	-	-
1943	59.5	-	52.00	17.40	-	-
1942	60.5	-	52.00	16.97	-	-
1941	61.5	-	52.00	16.54	-	-
1940	62.5	21,631	52.00	16.12	416	6,707
		55,253,257			1,062,563	45,201,796
AVERAGE SERVICE LIFE						52.00
AVERAGE REMAINING LIFE						42.54

Delta Natural Gas Company, Inc.

382 - Meter & Reg. Installation

SPR Results
Delta Natural Gas Company
Account: 382 - Meter & Regulator Installation

Curve	Life	Sum of Squared Differences	Index of Variation
BAND	**1940 - 2002**		
S0	63	2.21E+09	11
R2.5	44	2.23E+09	11
R2	52	2.24E+09	11
S0.5	53	2.27E+09	11
R3	38	2.36E+09	12
L1	61	2.41E+09	12
L1.5	52	2.48E+09	12
S1	44	2.56E+09	12
S1.5	41	2.77E+09	13
L2	44	2.89E+09	13
R1.5	63	2.94E+09	13
R4	34	3.16E+09	14
S2	37	3.27E+09	14
L3	37	3.72E+09	15
S3	34	4.14E+09	15
S6	33	4.28E+09	16
R5	33	4.28E+09	16
S5	33	4.30E+09	16
L4	34	4.42E+09	16
SQ	32	4.53E+09	16
S4	33	4.58E+09	16
L5	33	4.64E+09	16
L0.5	63	1.11E+10	25
R1	63	1.52E+10	30
S-0.5	63	3.23E+10	43
L0	63	4.37E+10	50
R0.5	63	5.39E+10	56
O1	63	1.18E+11	83
O2	63	1.72E+11	100
O3	63	4.78E+11	166
O4	63	1.02E+12	243

Minimum Equipment Life Expectancy: 8
Maximum Equipment Life Expectancy: 63
Life Expectancy Increment: 1
Begin Year: 1940
End Year: 2002
Year Fit Increment: 0

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

Account 382 - Meter and Regulator Installations

									3 Year Band					
Year	BOY Plant Balance a	Avg. Plant Balance b=(a+(a+1))/2	Single Year Additions c	Single Year Retirements d	Addition Ratio e = c/b	Retirement Ratio f = d/b	Geometric Mean Life Estimate g = 1/sqrt(e*f)	3 Year Band h	Avg. Plant Balance i	Additions j	Retirements k	Addition Ratio l = j/i	Retirement Ratio m = k/i	Geometric Mean Life Estimate n = 1/sqrt(l*m)
1940	-	193	386	-	2.00000	-	-	1940-42	965	386	-	0.40000	-	-
1941	386	386	-	-	-	-	-	1941-43	1,158	-	-	-	-	-
1942	386	386	-	-	-	-	-	1942-44	1,158	-	-	-	-	-
1943	386	386	-	-	-	-	-	1943-45	1,158	-	-	-	-	-
1944	386	386	-	-	-	-	-	1944-46	1,158	-	-	-	-	-
1945	386	386	-	-	-	-	-	1945-47	1,304	291	-	0.22325	-	-
1946	386	386	-	-	-	-	-	1946-48	1,866	834	-	0.44695	-	-
1947	386	532	291	-	0.54751	-	-	1947-49	3,229	1,891	-	0.58572	-	-
1948	677	949	543	-	0.57248	-	-	1948-50	5,534	2,720	-	0.49151	-	-
1949	1,220	1,749	1,057	-	0.60452	-	-	1949-51	8,875	3,961	-	0.44634	-	-
1950	2,277	2,837	1,120	-	0.39478	-	-	1950-52	12,454	3,197	-	0.25671	-	-
1951	3,397	4,289	1,784	-	0.41595	-	-	1951-53	15,288	2,471	-	0.16164	-	-
1952	5,181	5,328	293	-	0.05500	-	-	1952-54	17,700	2,353	-	0.13294	-	-
1953	5,474	5,671	394	-	0.06948	-	-	1953-55	21,371	4,989	-	0.23345	-	-
1954	5,868	6,701	1,666	-	0.24862	-	-	1954-56	30,540	13,349	-	0.43711	-	-
1955	7,534	8,999	2,929	-	0.32550	-	-	1955-57	47,157	19,885	-	0.42168	-	-
1956	10,463	14,840	8,754	-	0.58989	-	-	1956-58	68,688	23,178	-	0.33744	-	-
1957	19,217	23,318	8,202	-	0.35175	-	-	1957-59	89,912	19,270	-	0.21432	-	-
1958	27,419	30,530	6,222	-	0.20380	-	-	1958-60	107,074	15,054	-	0.14059	-	-
1959	33,641	36,064	4,846	-	0.13437	-	-	1959-61	120,670	12,138	-	0.10059	-	-
1960	38,487	40,480	3,986	-	0.09847	-	-	1960-62	135,073	16,686	18	0.12353	0.00013	246.47
1961	42,473	44,126	3,306	-	0.07492	-	-	1961-63	150,648	14,500	18	0.09625	0.00012	294.88
1962	45,779	50,467	9,394	18	0.18614	0.00036	122.73	1962-64	164,377	12,994	18	0.07905	0.00011	339.89
1963	55,155	56,055	1,800	-	0.03211	-	-	1963-65	173,805	5,880	-	0.03383	-	-
1964	56,955	57,855	1,800	-	0.03111	-	-	1964-66	179,829	6,168	-	0.03430	-	-
1965	58,755	59,895	2,280	-	0.03807	-	-	1965-67	187,173	8,520	-	0.04552	-	-
1966	61,035	62,079	2,088	-	0.03363	-	-	1966-68	197,465	12,063	-	0.06109	-	-
1967	63,123	65,199	4,152	-	0.06368	-	-	1967-69	212,809	18,626	-	0.08752	-	-
1968	67,275	70,187	5,823	-	0.08296	-	-	1968-70	233,566	22,887	-	0.09799	-	-
1969	73,098	77,424	8,651	-	0.11174	-	-	1969-71	256,550	23,081	-	0.08997	-	-
1970	81,749	85,956	8,413	-	0.09788	-	-	1970-72	278,703	21,225	-	0.07616	-	-
1971	90,162	93,171	6,017	-	0.06458	-	-	1971-73	300,160	21,689	-	0.07226	-	-
1972	96,179	99,577	6,795	-	0.06824	-	-	1972-74	321,661	21,313	-	0.06626	-	-
1973	102,974	107,413	8,877	-	0.08264	-	-	1973-75	341,609	18,583	-	0.05440	-	-
1974	111,851	114,672	5,641	-	0.04919	-	-	1974-76	357,175	12,549	-	0.03513	-	-
1975	117,492	119,525	4,065	-	0.03401	-	-	1975-77	368,008	9,117	-	0.02477	-	-
1976	121,557	122,979	2,843	-	0.02312	-	-	1976-78	375,894	6,656	-	0.01771	-	-
1977	124,400	125,505	2,209	-	0.01760	-	-	1977-79	383,360	8,276	-	0.02159	-	-
1978	126,609	127,411	1,604	-	0.01259	-	-	1978-80	393,132	11,267	-	0.02866	-	-
1979	128,213	130,445	4,463	-	0.03421	-	-	1979-81	409,620	21,709	-	0.05300	-	-
1980	132,676	135,276	5,200	-	0.03844	-	-	1980-82	462,009	83,786	716	0.18135	0.00155	59.65
1981	137,876	143,899	12,046	-	0.08371	-	-	1981-83	592,284	178,196	716	0.30086	0.00121	52.44
1982	149,922	182,834	66,540	716	0.36394	0.00392	26.49	1982-84	810,889	260,446	716	0.32119	0.00088	59.38
1983	215,746	265,551	99,610	-	0.37511	-	-	1983-85	1,071,369	261,230	-	0.24383	-	-
1984	315,356	362,504	94,296	-	0.26012	-	-	1984-86	1,316,767	231,308	1,742	0.17566	0.00132	65.60
1985	409,652	443,314	67,324	-	0.15187	-	-	1985-87	1,529,274	197,231	1,783	0.12897	0.00117	81.55
1986	476,976	510,949	69,688	1,742	0.13639	0.00341	46.37							
1987	544,922	575,011	60,219	41	0.10473	0.00007	365.95							

Delta Natural Gas Company
Gas Plant in Service
Geometric Mean Turnover Analysis

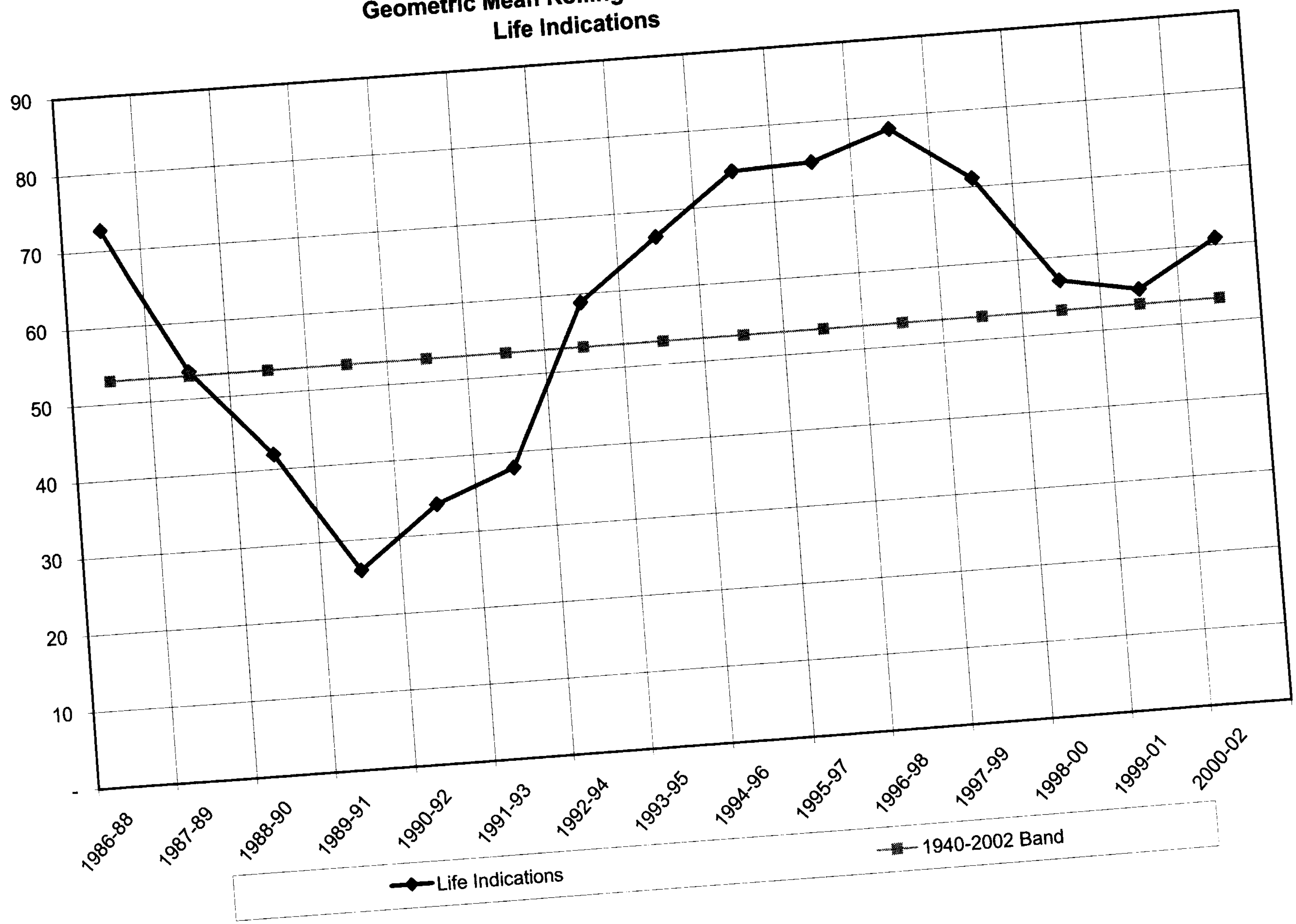
Account 382 - Meter and Regulator Installations

Year	BOY Plant Balance	Avg. Plant Balance	Single Year Additions	Single Year Retirements	Addition Ratio	Retirement Ratio	Geometric Mean Life Estimate	3 Year Band	3 Year Band: Avg. Plant Balance	3 Year Band: Additions	3 Year Band: Retirements	3 Year Band: Addition Ratio	3 Year Band: Retirement Ratio	3 Year Band: Geometric Mean Life Estimate
	a	b=(a+(a+1))/2	c	d	e = c/b	f = d/b	g = 1/sqrt(e*f)	h	i	j	k	l = j/i	m = k/i	n = 1/sqrt(l*m)
1988	605,100	640,291	71,400	1,018	0.11151	0.00159	75.10	1986-88	1,726,251	201,307	2,801	0.11662	0.00162	72.70
1989	675,482	867,409	385,719	1,866	0.44468	0.00215	32.33	1987-89	2,082,711	517,338	2,925	0.24840	0.00140	53.54
1990	1,059,335	1,131,354	147,697	3,659	0.13055	0.00323	48.67	1988-90	2,639,054	604,816	6,543	0.22918	0.00248	41.95
1991	1,203,373	1,253,656	118,996	18,430	0.09492	0.01470	26.77	1989-91	3,252,419	652,412	23,955	0.20059	0.00737	26.02
1992	1,303,939	1,386,005	170,332	6,200	0.12289	0.00447	42.65	1990-92	3,771,015	437,025	28,289	0.11589	0.00750	33.92
1993	1,468,071	1,537,533	142,352	3,428	0.09258	0.00223	69.60	1991-93	4,177,194	431,680	28,058	0.10334	0.00672	37.96
1994	1,606,995	1,685,638	160,617	3,331	0.09529	0.00198	72.88	1992-94	4,609,176	473,301	12,959	0.10269	0.00281	58.85
1995	1,764,281	1,835,363	148,177	6,014	0.08073	0.00328	61.48	1993-95	5,058,534	451,146	12,773	0.08919	0.00253	66.64
1996	1,906,444	1,980,589	150,837	2,548	0.07616	0.00129	101.03	1994-96	5,501,589	459,631	11,893	0.08355	0.00216	74.41
1997	2,054,733	2,126,913	149,850	5,491	0.07045	0.00258	74.15	1995-97	5,942,864	448,864	14,053	0.07553	0.00236	74.83
1998	2,199,092	2,282,124	172,095	6,032	0.07541	0.00264	70.83	1996-98	6,389,625	472,782	14,071	0.07399	0.00220	78.34
1999	2,365,155	2,439,092	155,766	7,892	0.06386	0.00324	69.57	1997-99	6,848,128	477,711	19,415	0.06976	0.00284	71.11
2000	2,513,029	2,562,839	122,090	22,470	0.04764	0.00877	48.93	1998-00	7,284,055	449,951	36,394	0.06177	0.00500	56.92
2001	2,612,649	2,651,556	98,891	21,077	0.03730	0.00795	58.08	1999-01	7,653,487	376,747	51,439	0.04923	0.00672	54.98
2002	2,690,463	2,731,925	93,543	10,619	0.03424	0.00389	86.68	2000-02	7,946,320	314,524	54,166	0.03958	0.00682	60.88
1940-2002	30,199,658	31,586,352	2,895,979	122,592	0.09168	0.00388	53.01							

Data Source: Response to PSC-2-17.

Company: Delta Natural Gas Company
Account: 382
Category: Meter and Reg. Installations

Geometric Mean Rolling Band Analysis
Life Indications



Delta Natural Gas Company

382 - Meter & Regulator Installation

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

44 S1

SURVIVOR CURVE..IOWA

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	93,216	44.00	43.50	2,119	92,153
2001	1.5	98,538	44.00	42.50	2,239	95,182
2000	2.5	121,623	44.00	41.51	2,764	114,746
1999	3.5	155,092	44.00	40.53	3,525	142,871
1998	4.5	171,205	44.00	39.57	3,891	153,956
1997	5.5	148,890	44.00	38.62	3,384	130,669
1996	6.5	149,617	44.00	37.68	3,400	128,127
1995	7.5	146,657	44.00	36.76	3,333	122,531
1994	8.5	158,530	44.00	35.86	3,603	129,210
1993	9.5	140,033	44.00	34.98	3,183	111,328
1992	10.5	166,894	44.00	34.12	3,793	129,410
1991	11.5	116,054	44.00	33.27	2,638	87,764
1990	12.5	143,277	44.00	32.45	3,256	105,666
1989	13.5	371,913	44.00	31.64	8,453	267,475
1988	14.5	68,377	44.00	30.86	1,554	47,953
1987	15.5	57,232	44.00	30.09	1,301	39,138
1986	16.5	65,676	44.00	29.34	1,493	43,793
1985	17.5	62,865	44.00	28.61	1,429	40,872
1984	18.5	87,167	44.00	27.89	1,981	55,255
1983	19.5	91,074	44.00	27.19	2,070	56,288
1982	20.5	60,120	44.00	26.51	1,366	36,226
1981	21.5	10,746	44.00	25.85	244	6,312
1980	22.5	4,575	44.00	25.20	104	2,620
1979	23.5	3,870	44.00	24.56	88	2,160
1978	24.5	1,369	44.00	23.94	31	745
1977	25.5	1,854	44.00	23.34	42	984
1976	26.5	2,345	44.00	22.74	53	1,212
1975	27.5	3,291	44.00	22.16	75	1,658
1974	28.5	4,477	44.00	21.60	102	2,197
1973	29.5	6,899	44.00	21.04	157	3,299
1972	30.5	5,166	44.00	20.50	117	2,407
1971	31.5	4,470	44.00	19.97	102	2,029
1970	32.5	6,100	44.00	19.45	139	2,696
1969	33.5	6,114	44.00	18.94	139	2,631
1968	34.5	4,007	44.00	18.44	91	1,679
1967	35.5	2,778	44.00	17.95	63	1,133

Delta Natural Gas Company

382 - Meter & Regulator Installation

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

44 S1

SURVIVOR CURVE..IOWA

1966	36.5	1,357	44.00	17.47	31	539
1965	37.5	1,437	44.00	16.99	33	555
1964	38.5	1,098	44.00	16.53	25	413
1963	39.5	1,062	44.00	16.08	24	388
1962	40.5	5,354	44.00	15.63	122	1,902
1961	41.5	1,817	44.00	15.19	41	627
1960	42.5	2,109	44.00	14.76	48	707
1959	43.5	2,464	44.00	14.34	56	803
1958	44.5	3,036	44.00	13.92	69	960
1957	45.5	3,834	44.00	13.51	87	1,177
1956	46.5	3,912	44.00	13.11	89	1,165
1955	47.5	1,249	44.00	12.71	28	361
1954	48.5	677	44.00	12.32	15	189
1953	49.5	152	44.00	11.93	3	41
1952	50.5	107	44.00	11.55	2	28
1951	51.5	618	44.00	11.18	14	157
1950	52.5	367	44.00	10.81	8	90
1949	53.5	326	44.00	10.44	7	77
1948	54.5	157	44.00	10.09	4	36
1947	55.5	79	44.00	9.73	2	17
1946	56.5	-	44.00	9.38	-	-
1945	57.5	-	44.00	9.04	-	-
1944	58.5	-	44.00	8.69	-	-
1943	59.5	-	44.00	8.36	-	-
1942	60.5	-	44.00	8.02	-	-
1941	61.5	-	44.00	7.69	-	-
1940	62.5	61	44.00	7.37	1	10
		2,773,387			63,032	2,174,622

AVERAGE SERVICE LIFE	44.00
AVERAGE REMAINING LIFE	34.50

Delta Natural Gas Company, Inc.

Exhibit___(MJM-2)

Snavely King Majoros O'Connor & Lee, Inc.

DELTA NATURAL GAS COMPANY
Calculation of Depreciation as of December 31, 2002

Account No.	Description	Plant Balance 1/	Book Reserve 2/	Seelye Proposed: ASL / Survivor Curve	Seelye Proposed: Remaining Life	Seelye Proposed: Net Salvage	Seelye Proposed: Future Accruals	Seelye Proposed: Calculated Annual Accrual Amount	Seelye Proposed: Calculated Annual Accrual Rate	Snavely King Recommended: Survivor Curve	Snavely King Recommended: Remaining Life	Snavely King Recommended: Net Salvage 3/	Snavely King Recommended: Future Accruals	Snavely King Recommended: Calculated Annual Accrual Amount	Snavely King Recommended: Calculated Annual Accrual Rate
	Gathering Plant														
305	Structures & Improvements	60,604	33,544				27,060	1,333	2.20%				27,060	1,333	2.20% 4/
325	Gathering Land & Rights	75,976	43,153				32,823	2,279	3.00%				32,823	2,279	3.00% 4/
331	Well Equipment - Fully Depr	7,795	7,795				-	312	4.00%				-	312	4.00% 4/
332	Gathering Lines	1,906,022	1,015,554	35 R3	20.8	0%	890,468	42,811	2.25%	35 R3	20.8	0%	890,468	42,811	2.25% 4/
333	Gathering Compressor Stations	818,994	531,087				287,907	32,760	4.00%				287,907	32,760	4.00% 4/
334	Gathering Meas & Reg Station Equip.	107,270	54,580	31 R3	18.0	0%	52,690	2,922	2.72%	31 R3	18.0	0%	52,690	2,922	2.72% 4/
	Total Gathering Plant	2,976,661	1,685,713				1,290,948	82,417					1,290,948	82,417	
	Storage & Processing														
351	Structures & Improvements	275,274	31,314	40.0			243,960	6,882	2.50%		40.0		243,960	6,099	2.22% 5/
352	Storage Wells	380,553	60,404	36.0			320,149	10,579	2.78%		36.0		320,149	8,893	2.34% 5/
35201	Storage Rights	850,395	243,324	36.0			607,071	23,641	2.78%		36.0		607,071	16,863	1.98% 5/
35202	Storage Reservoirs	1,861,730	578,675	36.0			1,283,055	51,756	2.78%		36.0		1,283,055	35,640	1.91% 5/
35203	Nonrecoverable Nat Gas	294,307	92,707	36.0			201,600	8,182	2.78%		36.0		201,600	5,600	1.90% 5/
353	Storage Lines	5,024,283	1,099,896	36.0			3,924,387	139,675	2.78%		36.0		3,924,387	109,011	2.17% 5/
354	Storage Comp Stat Equip	1,767,800	745,637	36.0			1,022,163	49,145	2.78%		36.0		1,022,163	28,393	1.61% 5/
355	Storage Meas & Reg Equip	361,994	68,548	36.0			293,446	10,063	2.78%		36.0		293,446	8,151	2.25% 5/
356	Purification Equipment	342,123	75,953	36.0			266,170	9,511	2.78%		36.0		266,170	7,394	2.16% 5/
357	Storage Other Equipment	47,208	30,856	30.0			16,352	1,572	3.33%		30.0		16,352	545	1.15% 5/
	Total Storage & Processing	11,205,667	3,027,314				8,178,353	311,006					8,178,353	226,590	
	Transmission														
3652	Rights Of Way														
3653	Land Rights Cvpl	163,626	161,844				1,782	4,091	2.50%				1,782	4,091	2.50% 4/
366	Structures & Improvements	173,215	82,663				90,552	3,464	2.00%				90,552	3,464	2.00% 4/
367	Transmission Mains	31,532,952	10,387,168	43 R3	30.2	0%	21,145,784	699,265	2.22%	43 R3	30.2	0%	21,145,784	699,265	2.22% 4/
368	Compressor Stat Equipment	1,413,310	1,099,553				313,757	28,266	2.00%				313,757	28,266	2.00% 4/
369	Meas & Reg Stat Equipment	2,017,415	500,967	39 S3	26.9	-10%	1,718,190	63,826	3.16%	45 R2.5	37.2	0%	1,516,448	40,809	2.02%
371	Other Equip	550,019	454,078				95,941	11,000	2.00%				95,941	11,000	2.00% 4/
	Total Transmission	35,850,537	12,686,273				23,366,006	809,913					23,164,264	786,895	
	Distribution														
375	Structures & Improvements	113,441	57,435	34 L3	17.9	0%	56,006	3,122	2.75%	34 L3	17.9	0%	56,006	3,122	2.75% 4/
376	Distribution Mains	55,253,257	17,850,403 6/				37,402,854	1,381,331	2.50%	52 S0	42.5	0%	37,402,854	879,240	1.59%
378	Meas & Reg Stat - General	1,137,407	310,481	36 R1	27.3	-10%	940,667	34,457	3.03%	36 R1	27.3	0%	826,926	30,290	2.66% 4/
379	Meas & Reg Stat - City Gate	398,371	170,030	37 R2	22.8	-10%	268,178	11,783	2.96%	37 R2	22.8	0%	228,341	10,033	2.52% 4/
380	Services						-	-	2.50%				-	-	1.59%
381	Meters	6,611,333	2,248,421	40 S1	29.3	0%	4,362,912	148,803	2.25%	40 S1	29.3	0%	4,362,912	148,803	2.25% 4/
382	Meter & Reg Installation	2,773,387	853,929	40 S1	27.4	-45%	3,167,482	115,602	4.17%	44 S1	34.5	0%	1,919,458	55,636	2.01%
383	House Reg	2,570,545	809,873	28 S6	16.4	5%	1,632,145	99,764	3.88%	28 S6	16.4	0%	1,760,672	107,621	4.19% 4/
385	Industrial Meter Sets	1,348,030	356,706	43 R1	35.1	-10%	1,126,127	32,083	2.38%	43 R1	35.1	0%	991,324	28,243	2.10% 4/
	Total Distribution	70,205,771	22,657,278				48,956,371	1,826,945					47,548,493	1,262,987	

DELTA NATURAL GAS COMPANY
Calculation of Depreciation as of December 31, 2002

				Seelye Proposed						Snavely King Recommended					
Account No.	Description	Plant Balance 1/	Book Reserve 2/	ASL / Survivor Curve	Remaining Life	Net Salvage	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Survivor Curve	Remaining Life	Net Salvage 3/	Future Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	General														
390	Structures & Improvements	4,536,749	1,130,926	17 L0	9.9	5%	3,405,823	90,735	2.00%	17 L0	9.9	0%	3,405,823	90,735	2.00% 4/
391	Office Furn & Equip	644,923	470,640	6 L3	1.6	30%	142,037	14,347	2.22%	6 L3	1.6	30%	174,283	17,604	2.73% 4/
392	Transportation Equipment	3,388,583	1,957,845				414,163	263,798	7.78%				414,163	263,798	7.78% 4/
393	Stores Equipment	49,526	42,436				7,090	2,476	5.00%				7,090	2,476	5.00% 4/
394	Tools & Work Equipment	584,283	450,798	14 L4	5.3		133,485	29,214	5.00%	14 L4	5.3		133,485	29,214	5.00% 4/
395	Laboratory Equipment	187,689	113,913				73,776	13,816	7.36%				73,776	13,816	7.36% 4/
396	Power Operated Equipment	2,520,359	1,334,406	14 S2	6.4	5%	1,185,953	50,407	2.00%	14 S2	6.4	0%	1,185,953	50,407	2.00% 4/
397	Communication Equip	547,343	291,789				228,187	35,935	6.57%				255,554	40,245	7.35% 4/
398	Miscellaneous Equipment	93,747	81,847				11,900	4,687	5.00%				11,900	4,687	5.00% 4/
3991	Mapping Costs	662,043	522,473				139,570	66,204	10.00%				139,570	66,204	10.00% 4/
3992	Computer Software	1,773,888	1,513,343				260,545	354,778	20.00%				260,545	354,778	20.00% 4/
		14,989,133	7,910,416				6,002,529	926,398					6,062,142	933,965	
	Total General							3,956,680						3,292,855	
	Total Depreciation														
	5-Year Average Net Salvage Allowance (Excludes Transportation and Power Operated Equip.)							-						11,274	
	Total Depreciation and Net Salvage Allowance							3,956,680						3,304,129	

1/ Study Appendix B
2/ Response to AG 52, pages 362 and 363.
3/ Accept Seeley proposed positive net salvage for Transportation - use zero net salvage for all other accounts.
4/ No objection to Seeley life proposal.
5/ Seeley estimated remaining lives but calculated whole-life rates. Snavely King calculated remaining life rates using Seeley estimates.
6/ Account 380 Services Reserve added to Account 376 because that is where the Account 380 investment is.

DELTA NATURAL GAS COMPANY, INC
PLANT BALANCES AND CALCULATED DEPRECIATION EXPENS
AS OF 12/31/03
COMPARISON OF COMPANY PROPOSED RATES AND SNAVELY KING RECOMMENDED RATES

			SEELYE PROPOSED		SNAVELY KING RECOMMENDED	
ACCT NO	DESCRIPTION	DELTA 12/31/03	DEPR RATE	DEPR CALCULATED	DEPR RATE	DEPR CALCULATED
301	ORGANIZATION	53,151	0.0%	-	0.0%	-
302	FRANCHISE & CONSENT	-	0.0%	-	0.0%	-
	SUB TOTAL	53,151		-		-
	PRODUCTION					
304	LAND & RIGHTS	35,377	0.00%	-	0.00%	-
305	STRUCTURES & IMPROVEMENTS	-	2.20%	-	2.20%	-
325	RIGHT OF WAYS	75,975	3.00%	2,279	3.00%	2,279
327	COMP STAT STRUCTURES	42,950	3.00%	1,289	3.00%	1,289
331	WELL EQUIPMENT - FULLY DEPR	7,795	4.00%	-	4.00%	-
332	FIELD LINES	1,904,404	2.25%	42,849	2.25%	42,849
333	COMPRESSOR STAT EQUIPMENT	823,368	4.00%	32,935	4.00%	32,935
334	MEAS & REG STATIONS	105,138	2.72%	2,860	2.72%	2,860
	SUB TOTAL	2,995,007		82,212		82,212
	STORAGE & PROCESSING					
35001	STORAGE LAND	14,142	0.00%	-	0.00%	-
35002	STORAGE RIGHT OF WAY	177,425	0.00%	-	0.00%	-
35005	GAS RIGHTS WELL	1,495	0.00%	-	0.00%	-
35006	GAS RIGHTS STOR	-	5.00%	-	5.00%	-
351	STRUCTURES & IMPROVEMENTS	275,273	2.50%	6,882	2.22%	6,111
352	STORAGE WELLS	360,583	2.78%	10,024	2.34%	8,438
35201	STORAGE RIGHTS	860,396	2.78%	23,919	1.98%	17,036
35202	STORAGE RESERVOIRS	1,881,731	2.78%	52,312	1.91%	35,941
35203	NONRECOVERABLE NAT GAS	294,307	2.78%	8,182	1.90%	5,592
353	STORAGE LINES	5,024,284	2.78%	139,675	2.17%	109,027
354	STORAGE COMP STAT EQUIP	2,417,969	2.78%	67,220	1.61%	38,929
355	STORAGE MEAS & REG EQUIP	361,994	2.78%	10,063	2.25%	8,145
356	PURIFICATION EQUIPMENT	346,373	2.78%	9,629	2.16%	7,482
357	STORAGE OTHER EQUIPMENT	47,209	3.33%	1,572	1.15%	543
	SUB TOTAL	12,063,181		329,478		237,244
	TRANSMISSION					
3651	LAND & RIGHTS	56,724	0.00%	-	0.00%	-
3652	RIGHTS OF WAY	1,073,062	0.00%	-	0.00%	-
3653	LAND RIGHTS CVPL	163,626	2.50%	4,091	2.50%	4,091
366	STRUCTURES & IMPROVEMENTS	173,215	2.00%	3,464	2.00%	3,464
367	TRANSMISSION MAINS	35,592,709	2.22%	790,158	2.22%	790,158
368	COMPRESSOR STAT EQUIPMENT	1,856,757	2.00%	37,135	2.00%	37,135
369	MEAS & REG STAT EQUIPMENT	2,096,287	3.16%	66,243	2.02%	42,345
371	OTHER EQUIP	598,623	2.00%	11,972	2.00%	11,972
	SUB TOTAL	41,611,003		913,063		889,165

DELTA NATURAL GAS COMPANY, INC
PLANT BALANCES AND CALCULATED DEPRECIATION EXPENS
AS OF 12/31/03
COMPARISON OF COMPANY PROPOSED RATES AND SNAVELY KING RECOMMENDED RATES

			SEELYE PROPOSED		SNAVELY KING RECOMMENDED	
ACCT NO	**DESCRIPTION**	**DELTA 12/31/03**	**DEPR RATE**	**DEPR CALCULATED**	**DEPR RATE**	**DEPR CALCULATED**
	DISTRIBUTION					
374	LAND & RIGHTS	280,647	0.00%	-	0.00%	-
375	STRUCTURES & IMPROVEMENTS	116,064	2.75%	3,192	2.75%	3,192
376	DISTRIBUTION MAINS	56,694,785	2.50%	1,417,370	1.59%	901,447
378	MEAS & REG STAT - GENERAL	1,252,562	3.03%	37,953	2.66%	33,318
379	MEAS & REG STAT - CITY GATE	398,371	2.96%	11,792	2.52%	10,039
380	SERVICES	10,856,853	2.50%	271,421	1.59%	172,624
381	METERS	8,426,711	2.25%	189,601	2.25%	189,601
382	METER & REG INSTALLATION	2,865,091	4.17%	119,474	2.01%	57,588
383	HOUSE REG	2,679,313	3.88%	103,957	4.19%	112,263
385	INDUSTRIAL METER SETS	1,400,779	2.38%	33,339	2.10%	29,416
387	OTHER EQUIP	-	3.00%	-	3.00%	-
	SUB TOTAL	84,971,176		2,188,099		1,509,488
	GENERAL					
389	LAND & RIGHTS	1,038,741	0.00%	-	0.00%	-
390	STRUCTURES & IMPROVEMENTS	5,086,091	2.00%	101,722	2.00%	101,722
391	OFFICE FURN & EQUIP-FULLY DEPR	383,973	0.00%	-		
391	OFFICE FURN & EQUIP	259,494	2.23%	5,787		
	OFFICE FURN & EQUIP - TOTAL	643,467		5,787	2.73%	17,567
392	AUTOS & TRUCKS-FULLY DEPR	657,064	0.00%	-		
392	AUTOS & TRUCKS	2,888,892	7.77%	224,467		
	AUTOS & TRUCKS - TOTAL	3,545,956		224,467	7.77%	275,521
393	STORES EQUIPMENT-FULLY DEPR	41,129	0.00%	-	0.00%	-
393	STORES EQUIPMENT	14,885	5.00%	744	5.00%	744
394	TOOLS & WORK EQUIP-FULLY DEPR	410,969	0.00%	-	0.00%	-
394	TOOLS & WORK EQUIPMENT	177,464	5.00%	8,873	5.00%	8,873
39401	COMP NG STAT & EQUIP-FULLY DEPR	283,352	0.00%	-	0.00%	-
395	LABORATORY EQUIPM-FULLY DEPR	79,851	0.00%	-		
395	LABORATORY EQUIPMENT	108,372	7.38%	7,998		
	LABORATORY EQUIPMENT - TOTAL	188,223		7,998	7.38%	13,891
396	POWER OPERATED EQUIP-FULLY DEPR	905,879	0.00%	-	0.00%	-
396	POWER OPERATED EQUIPMENT	1,669,678	2.00%	33,394	2.00%	33,394
397	COMMUNICATION EQUIP-FULLY DEPR	228,431	0.00%	-		
397	COMMUNICATION EQUIP	322,540	6.56%	21,159		
	COMMUNICATION EQUIP - TOTAL	550,971		21,159	7.35%	40,496

DELTA NATURAL GAS COMPANY, INC
PLANT BALANCES AND CALCULATED DEPRECIATION EXPENS
AS OF 12/31/03
COMPARISON OF COMPANY PROPOSED RATES AND SNAVELY KING RECOMMENDED RATES

ACCT NO	DESCRIPTION	DELTA 12/31/03	SEELYE PROPOSED DEPR RATE	SEELYE PROPOSED DEPR CALCULATED	SNAVELY KING RECOMMENDED DEPR RATE	SNAVELY KING RECOMMENDED DEPR CALCULATED
398	MISCELLANEOUS EQUIP-FULLY DEPR	78,767	0.00%	-	0.00%	-
398	MISCELLANEOUS EQUIPMENT	16,011	5.00%	801	5.00%	801
3991	OTHER TANG EQUIP-FULLY DEPR	430,596	0.00%	-	0.00%	-
3991	OTHER TANG EQUIP	231,447	10.00%	23,145	10.00%	23,145
3992	COMPUTER SOFTWARE-FULLY DEPR	1,450,628	0.00%	-	0.00%	-
3992	COMPUTER SOFTWARE	577,538	20.00%	115,508	20.00%	115,508
3993	COMPUTER HARDWARE-FULLY DEPR	603,319	0.00%	-	0.00%	-
3993	COMPUTER HARDWARE	995,912	20.00%	199,182	20.00%	199,182
	SUB TOTAL	18,941,023		742,780		830,843
	TOTAL A/C 101	**160,634,541**		**4,255,632**		**3,548,952**
110701	Constr Work In Progress at 12/31/03					
	Acct 325 CWIP	12	3.00%	-	3.00%	-
	Acct 351 CWIP	13,145	2.50%	329	2.22%	292
	Acct 354 CWIP	940	2.78%	26	1.61%	15
	Acct 36501 CWIP	250	0.00%	-	0.00%	-
	Acct 36502 CWIP	62	0.00%	-	0.00%	-
	Acct 366 CWIP	4,838	2.00%	97	2.00%	97
	Acct 367 CWIP	1,403,612	2.22%	31,160	2.22%	31,160
	Acct 369 CWIP	881	3.16%	28	2.02%	18
	Acct 371 CWIP	6,908	2.00%	138	2.00%	138
	Acct 374 CWIP	96	0.00%	-	0.00%	-
	Acct 376 CWIP	138,988	2.50%	3,475	1.59%	2,210
	Acct 378 CWIP	63	3.03%	2	2.66%	2
	Acct 379 CWIP	5,062	2.96%	150	2.52%	128
	Acct 380 CWIP	160	2.50%	4	1.59%	3
	Acct 383 CWIP	12,263	3.88%	476	4.19%	514
	Acct 385 CWIP	271	2.38%	6	2.10%	6
	Acct 390 CWIP	130,036	2.00%	2,601	2.00%	2,601
	Acct 394 CWIP	19,648	5.00%	982	5.00%	982
	Acct 397 CWIP	2,928	6.56%	192	7.35%	215
	Acct 398 CWIP	1,818	5.00%	91	5.00%	91
	Acct 39902 CWIP	17,027	20.00%	3,405	20.00%	3,405
	Acct 39903 CWIP	20,702	20.00%	4,140	20.00%	4,140
	WO 53010	(47,143)				
	TOTAL	1,732,567		**47,302**		**46,017**
	LESS:					
	TRANSPORTATION EQUIP			(224,467)		(275,521)
	POWER OPERATED EQUIP			(33,394)		(33,394)
				(257,861)		(308,914)
	PLUS:					
	FIVE-YEAR AVERAGE NET SALVAGE ALLOWANCE			-		11,274
	TOTAL			4,045,073		3,297,329

DELTA NATURAL GAS COMPANY, INC
PLANT BALANCES AND CALCULATED DEPRECIATION EXPENS
AS OF 12/31/03
COMPARISON OF COMPANY PROPOSED RATES AND SNAVELY KING RECOMMENDED RATES

ACCT NO	DESCRIPTION	DELTA 12/31/03	SEELYE PROPOSED DEPR RATE	SEELYE PROPOSED DEPR CALCULATED	SNAVELY KING RECOMMENDED DEPR RATE	SNAVELY KING RECOMMENDED DEPR CALCULATED
	<u>Reconciliation to Financial Statement</u>					
	<u>Reported Above</u>					
	Plant 1.301 thru 1.399.03	160,634,541				
	Construction Work In Progress 1.107.01	1,732,567				
	<u>Not included Above</u>					
	Acquisition Adjustment - Tranex 1.114	(1,045,704)				
	Acquisition Adjustment - Mt Olivet 1.114.01	464,945				
	Gas Stored Underground - 1.117	4,208,069				
	Total	165,994,418				

Delta Natural Gas Company
Net Salvage Experience
Years Ending 12/31

	Salvage	Cost of Removal	Net Salvage
Gathering Plant			
1998	-	-	-
1999	-	-	-
2000	-	-	-
2001	-	-	-
2002	-	-	-
Five Year Total	-	-	-
Five Year Average	-	-	-
Storage & Processing Plant			
1998	-	-	-
1999	-	-	-
2000	-	-	-
2001	-	-	-
2002	-	-	-
Five Year Total	-	-	-
Five Year Average	-	-	-
Transmission Plant			
1998	-	-	-
1999	-	-	-
2000	-	21,388	(21,388)
2001	-	-	-
2002	-		
Five Year Total	-	21,388	(21,388)
Five Year Average	-	4,278	(4,278)
Distribution Plant			
1998	408	10,528	(10,120)
1999	645	16,243	(15,598)
2000	2,663	16,989	(14,326)
2001	-	57,138	(57,138)
2002	265	17,227	(16,962)
Five Year Total	3,981	118,125	(114,144)
Five Year Average	796	23,625	(22,829)
General Plant (Excluding Transportation and Power Operated Equipment)			
1998	50,201	-	50,201
1999	2,400	-	2,400
2000	7,600	-	7,600
2001	18,325	-	18,325
2002	634	-	634
Five Year Total	79,160	-	79,160
Five Year Average	15,832	-	15,832
Total Plant (Excluding Transportation and Power Operated Equipment)			
1998	50,609	10,528	40,081
1999	3,045	16,243	(13,198)
2000	10,263	16,989	(6,726)
2001	18,325	78,526	(60,201)
2002	899	17,227	(16,328)
Grand Total	83,141	139,513	(56,372)
Average	16,628	27,903	(11,274)

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
State Regulatory Agencies			
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.

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1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa

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1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia

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2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	
24/ Delaware Public Service Comm.	
25/ Conn. Ofc. Of Consumer Counsel	
26/ Arizona Corp. Commission	
27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

Charles W. King

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY FOR AN ADJUSTMENT OF RATES	))	CASE NO. 2004-00067

DIRECT TESTIMONY

AND EXHIBITS

OF

CHARLES W. KING

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

July 2, 2004

DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 34-year history, members of the firm have participated in over "1,000" proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Attorney General of Kentucky.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to recommend the appropriate rate of return to common equity for Delta Natural Gas Company ("Delta" or "the Company").

SUMMARY

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN FOR DELTA?

A. Based on the analyses presented in this testimony, I find that the appropriate return to the equity capital of Delta Natural Gas is **10.05 percent.** Using the Company's capital structure and debt costs, the return to overall capital is **7.64 percent.**

STANDARDS FOR FINDING EQUITY CAPITAL COST

Q. WHAT IS THE BASIS FOR FINDING A RATE OF RETURN TO DELTA'S COMMON EQUITY SHAREHOLDERS?

A. In its landmark Hope Natural Gas decision, the United States Supreme Court established the following standards for the return to equity that must be allowed a regulated public utility:

> ..the return to the equity owner should be commensurate with the 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.[1]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return to equity. The first is the "comparable earnings" standard, that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that they must be sufficient to assure "confidence in the financial integrity of the enterprise," and the third is that they must allow the utility to be able to attract capital.

Q. HOW CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. There is a certain circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to <u>all</u> enterprises having corresponding risks are comparable with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings in comparison with the present and prospective earnings of all other stocks and other investments available to them. If the earnings of a firm are depressed, then investors will pay only a low price for that firm's stock. As a result, their return on the market value of that stock will be comparable to the return on the market value of the stock of other highly profitable companies which, as a consequence of their profitability, have been bid up to a very high price. Thus, if "return" is defined as the earnings of an equity investment relative to its current market price, then the comparable earnings test becomes a cipher. All returns are comparable with all other returns.

In public utility regulation the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That return is combined with the cost of debt and preferred stock, using either the actual or a hypothetical minimum-cost capital structure. The blended return to total capital is then

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[1] <u>Federal Power Commission et. al. vs. Hope Natural Gas Company</u>, 320 U.S. 592, at 603 (1944).

applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings which regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. If the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to shun such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. HOW WILL YOU IDENTIFY THE MARKET-DETERMINED RATE OF RETURN TO THE DELTA'S EQUITY CAPITAL INVESTMENT?

A. I shall first apply the Discounted Cash Flow ("DCF") procedure, which I consider to be the most accurate test of a market return. As I shall discuss, there are broadly two versions of this test, one of which requires the use of the forecasts of investment analysts. Because of Delta's small size, it has not been as intensively studied by investment analysts as have other, larger gas distribution companies. For this test, I will therefore examine a "peer group" of companies in addition to Delta. The other DCF formulation relies on Delta-specific data. Additionally, I shall consider the capital asset pricing model, recognizing that the inputs to this model require consider exercise of judgment. However, it does provide a useful check on the DCF results, and it can be applied specifically to Delta.

DISCOUNTED CASH FLOW PROCEDURE

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW PROCEDURE.

A. The basic premise of the Discounted Cash Flow ("DCF") procedure is that the market values each stock at the discounted present value of all future flows of cash that investors expect from purchasing that stock. The discount rate that equates those future cash flows with the market value of the stock is the investors' required rate of return.

The DCF approach is usually represented by the following formula:

$$k = {}^{d}/_{P} + g$$

where k = required rate of return
d = dividend in the immediate period
P = market price
g = expected growth rate in dividends

While the DCF method is usually presented in mathematical notation format (as above), it can also be described in narrative fashion. The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. 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 test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price.

Q. DON'T MOST INVESTORS REGARD CAPITAL APPRECIATION AS A PORTION OF THEIR EXPECTED RETURN?

A. Yes. The expectation of capital appreciation is captured in the "g" or growth portion of the DCF formula. If dividends grow, then it follows that the market price of the stock will grow as well. It is this growth that most equity investors seek, at least in part, in purchasing shares in a traded company.

Q. HOW IS THE FIRST TERM "d/p" DEVELOPED FOR PURPOSES OF THE DCF PROCEDURE?

A. The "d" is the dividend in the next period, that is, the next year. There is a somewhat mechanical procedure for predicting this value which applies a factor of .5 to the "g" or growth factor, on the assumption that dividends will increase in lock step with earnings growth. I have used this procedure for Delta because there are no other forecasts of Delta's dividends. For the other companies studied, I have used an average of the 2004 and 2005 dividends as forecast by Value Line.

The "P" or price denominator of the dividend yield fraction requires the exercise of some judgment. Given the volatility of the stock market, it is inappropriate to use any one day's price, but it is also necessary to reflect market's current perception of each stock's value. For purposes of this analysis, I have therefore used the average of three values: the historical high for 2004 to date, the historical low for 2005 to date, and the market price on June 24, 2004, the day of this writing.

Q. IS THERE A CONVENTIONAL PROCEDURE FOR CALCULATING THE "g" GROWTH COMPONENT OF THE DCF FORMULATION?

A. Yes. There is a conventional procedure for calculating equity return under the DCF formula that is often referred to as the "classic" DCF calculation. The Federal Communications Commission ("FCC") concluded that this method should be given the greatest weight in determining the rate of return to equity.[2] I agree with this conclusion.

[2] *Notice Initiating a Prescription Proceeding and Notice of Proposed Rulemaking,* CC Docket No. 98-166, October 5, 1998.

According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and they do not necessarily reflect the underlying driver of earnings. Simply by changing the dividend payout ratio, a company's management can create a rate of dividend growth that is unsustainable. For this reason, it is generally accepted that earnings per share ("EPS") is the most reliable indicator of the "g" factor.

The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast future earnings of traded companies. Value Line provides such forecasts based on the research of its own and other organizations' analysts. It is those forecasts that I have used for my development of the gas distribution industry's DCF return.

Q. HAVE YOU PRESENTED SUCH A "CLASSIC" DCF FORMULATION FOR DELTA GAS?

A. Yes. I have developed a "classic" DCF return for Delta, which is presented on the first line of Exhibit_____(CWK-1). I derived the $1.20 2004 dividend by multiplying the 2003 dividend of $1.18 by one-half Value Line's three percent growth forecast. I applied the same inflator to the 2004 dividend to arrive a t a $1.22 dividend for 2005. The average dividend for the coming year is therefore predicted to be $1.21. Delta's highest stock price during 2004 has been $27.78, and its lowest price has been $23.00. Its price on June 24, 2004 was $23.31. The average of those three prices is $24.70. The result of the fraction $1.21/24.70 is a dividend yield of 4.9 percent.

Value Line states that the consensus 5–year earnings growth forecast for Delta is 3 percent.[3] The sum of 4.9 percent dividend yield and 3.0 percent future growth is 7.9 percent.

[3] Delta's rate-of-return witness Blake asserts that Value Line's earnings growth forecast was 6.5% at the time he prepared his testimony. The Value Line sheet he provided shows that the consensus forecast at that time was 4.0%. The 6.5% that Dr. Blake used was the historical rate of earnings growth over the past five years.

Q. DO YOU PLACE MUCH CREDIBILITY IN THIS RESULT?

A. No. Value Line concedes that the three percent growth estimate is based on only one analyst's estimate. Unlike other growth forecasts, this figure does not represent the consensus of multiple analysts each examining the company independently.

Q. IS THERE AN ALTERNTIVE WAY TO APPLY THE CLASSIC DCF FORMULATION TO DELTA?

A. Yes. The preferred alternative is to apply the classic DCF formulation to enterprises having comparable levels of risk to Delta but for which there is a broader consensus of estimates of future growth.

Q. FOR PURPOSES OF THIS INQUIRY, WHAT TYPES OF ENTERPRISES HAVE COMPARABLE RISK TO DELTA?

A. The enterprises likely to have business risks most comparable to Delta are those engaged in the same business, that is, the distribution of gas to retail customers under rate base/rate-of-return regulation.

Q. HAVE YOU IDENTIFIED SPECIFIC GAS DISTRIBUTION COMPANIES FOR WHICH THERE ARE MORE ANALYSTS' FORECASTS OF EARNINGS GROWTH?

A. Yes. Value Line lists 19 "Peer Group" gas distribution companies that trade on the New York Stock Exchange. Since these Companies trade on the Big Board, they unquestionably receive more attention from investment analysts than does Delta.

However, since we are attempting to find a rate of return sufficient to maintain credit and attract capital, we cannot examine utilities that are financially weak. Two of the 19 Value Line gas distribution companies (Semco Energy and NUI Corporation) are rated by Value Line as below "B" for "financial strength," and for this reason I have excluded them. The remaining 17 companies are as follows:

AGL Resources
Atmos Energy
Cascade Natural Gas
Energen
Energy West
KeySpan
Laclede Group
New Jersey Resources
NICOR
Northwest Natural Gas
People's Energy
Piedmont National
RGC Resources
Southern Union
South Jersey Industries
Southwest Gas
UGI Corp
WGL Holdings.

Q. HAVE YOU DEVELOPED CLASSIC DCF RESULTS FOR THESE COMPANIES?

A. Yes. The result of my analysis of 16 of these companies is presented in Exhibit_____(CWK-1). It was necessary to drop one company, Southern Union, because it issues no dividends, nor is it forecast to by Value Line. Since the DCF procedure is intended to reflect the discount rate of present and future dividend flows, this company cannot reasonably be considered in the peer group for purposes of the DCF calculation.

As the exhibit demonstrates, I used the same procedure for identifying the DCF return for the 16 peer group companies as I used for Delta, with one exception. For these companies, I used the 2004 and 2005 dividends forecast by Value Line (columns A and B) to derive the expected dividend yield.

The exhibit reveals that the DCF returns range from 5.7 percent to 14.1 percent, with an average of 9.4 percent.

Q. IS THIS 9.4 PERCENT APPROPRIATE FOR DELTA?

A. That is likely to be the subject of considerable controversy. Delta's rate of return witness, Dr. Blake, asserts that there are three reasons to believe that Delta's rate of return should be higher than those of other gas distribution utilities. First, he states that Delta is more leveraged, that is, it has a much higher ratio of debt to equity, than other gas distribution utilities. Second, he argues that the rural nature of Delta's service territory and its consequent heavy reliance on highly weather-sensitive consumption increase Delta's risk relative to utilities that serve more urban areas with larger non-weather sensitive commercial and industrial loads. Finally, he argues that the small size of Delta justifies an "adder" to its rate of return.

Q. IS DELTA MORE LEVERAGED THAN OTHER UTILITIES?

A. No. Exhibit _____(CWK-2) presents the capital structures of the 16 gas distribution companies in Exhibit_____(CWK-1) plus two small companies, Energy West and RGC Resources, that Dr. Blake included in his exhibits. In this exhibit, I have shown the equity percentage inclusive and exclusive of short-term debt, and I have shown Delta's capital structure on September 30, 2003, December 31, 2003 and March 30, 2004.

The exhibit reveals that on September 30, 2003, Delta's equity percentage was lower than all but four of the 18 comparison companies when short-term debt is included and all but five of the companies when it is excluded. However, by March 31, 2004, Delta's equity proportion had increased above the average for the 18 companies when short-term debt is included, and it approached the average when short-term debt is excluded.

I conclude that there is no justification for any adjustment to Delta's rate of return on account of its capital structure.

Q. DOES THE RURAL NATURE OF DELTA'S SERVICE TERRITORY JUSTIFY ANY ADJUSTMENT TO ITS RATE OF RETURN?

A. The principal effect of Delta's rural service territory is that the absence of commercial or industrial customers makes the Company unusually dependent upon highly temperature-sensitive heating loads. That might have been a valid reason to increase Delta's rate of return prior to 1999, but in that year, the Commission adopted a weather normalization adjustment that largely protects Delta from the effect of temperature variations. When the weather is unusually warm, Delta is permitted to increase its base rate charge to account for the low volume of heating gas it sells. When the weather is unusually cold, Delta reduces its charge to recognize the excessive sales of gas. This protection has been cited in a number of analysts' reports as a reason to consider Delta as being somewhat less risky than gas utilities that do not have such rate feature.[4]

Q. DOES DELTA'S SMALL SIZE JUSTIFY AN "ADDER" TO ITS RATE OF RETURN?

A. Again, this question is certain to be an area of considerable controversy. Anyone with even a passing familiarity with the stock indices knows that the NASDAQ index, composed principally of small companies, is far more volatile than is the NYSE index, the S&P 500 index, or the Dow Jones index, all of which are composed of the nation's largest companies. Ibbotson Associates reports a study by the Center for Research in Securities Prices of the University of Chicago's Business School that reveals that small companies have over time earned higher rates of return to equity than large companies. Moreover, the variation in those rates of return has been higher as well – implying greater risk.

[4] See response to AG Data Request No. 133.

Whether these general observations justify some sort of small size increment in Delta's rate of return is another matter. Small companies tend to bit players in the competitive market, subject to the marketing (and sometimes the pricing) power of the larger companies that dominate their industries. Delta does not face direct competition for its gas distribution service within its service area.

Small companies also tend to have very unstable earnings. Delta's earnings may not have been as high as the Company could wish, but they have remained within a band of $.75 to $1.49 per share over the last 10 years. More important, since the institution of the weather normalization adjustment in 1999, the Company's annual earnings have varied within the range of $1.42 to $1.49 per share, suggesting a very stable level of profit.

Q. DO YOU HAVE ANY INDEPENDENT SUPPORT FOR YOUR BELIEF THAT DELTA EXPERIENCES VERY LOW EARNINGS RISK?

A. Yes. In a report dated June 13, 2003, the analyst firm of Stifel, Nicolaus & Company made the following comments concerning Delta:

> We consider DGAS [Delta's ticker symbol] to be very stable, both operationally and financially. The company has several strategic positives in place, including extensive storage capacity enabling the company to better manage its natural gas supply, a rate structure that adjusts based on temperature deviations from historical averages, and a customer base that is growing at an annual rate approximately in line with the national average. In addition, we anticipate that DGAS will be filing a general rate case with Kentucky regulators in FY '04, which likely result in increased allowable revenues. The strong operating history of DGAS is reflected in the stability of dividend, which has been paid every year since 1964.

A report by Edward Jones, dated June 19, 2002 recommended that investors maintain their Delta shares for growth and income purposes. It cited the protection of the weather normalization program, customer growth and an attractive dividend yield.

Q. IS THERE ANY COUNTER-ARGUMENT THAT A "SMALL COMPANY" ADJUSTMENT SHOULD BE ADDED TO DELTA'S RATE OF RETURN?

A. Yes. A number of analysts have recommended Delta to investors because of its high dividend yield. The high dividend yield suggests that the Company's stock is under-priced relative to other companies of comparable risk. One analyst (Edward Jones) noted that this underpricing might be due to the Company's small size. Thus, an argument could be made that Delta's small size does have an impact on its required rate of return.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SMALL COMPANY ADJUSTMENT FOR DELTA GAS?

A. I recommend that the Commission look at both size-adjusted and non-size-adjusted comparable industry returns as outer limits on the DCF return that could reasonably be applied to Delta.

Q. ASSUMING THAT COMPANY SIZE DOES HAVE AN INFLUENCE ON DELTA'S REQUIRED RETURN, WHAT ADJUSTMENT WOULD BE APPROPRIATE FOR THAT EFFECT?

A. Most of the gas distribution companies that I have used for comparison purposes are classified as "mid-cap," with market capitalization in the range of $1.5 to $5 billion. Delta, with a market capitalization of about $75 million, is in the "micro-cap" range. The University of Chicago study reveals that the historical difference between the geometric means of the earnings of these two categories of companies is 1.4 percentage points.[5] Assuming that this figure is the appropriate company size adjustment for the peer group's DCF results, the indicated size-adjusted rate of return for Delta is 10.8 percent, as shown on Exhibit_____(CWK-1). On this basis, the range of the DCF return appropriate for Delta is between 9.4 and 10.8 percent.

Q. IS THERE ANY OTHER DCF FORMULATION THAT IS LESS DEPENDENT UPON COMPARISONS WITH COMPANIES OF VERY DIFFERENT SIZES FROM DELTA?

[5] As reported in Ibbotson Associates 2004 SBBI Yearbook, page 128.

A. Yes. It is possible to estimate the "g" or growth component in the DCF formula by examining Delta's ability to generated increases in the book value of its stock. While book value and market value rarely match,[6] they do have a relationship, particularly for a company that is subject to rate-base/rate-of-return regulation. As I have discussed earlier, regulation sets the company's allowed earnings based on book value. As long as that is the case, market value will in large measure be driven by book value.

There are two ways in which the book value per share of a regulated company can increase. One is through retained earnings, that is, the portion of earnings that is not declared out as dividends. The other is to sell new shares of stock at prices that exceed book value. The premium on the new shares then increases the book value of the existing shares.

These terms can be expressed by the following formula:

$g = (R*B) + (S*V)$

where:

R = the fraction of earnings retained by the company, i.e. the retention ratio

B = the return on the book value of common equity

S = the increase in common shares outstanding that have been sold at market value

V = the per-share premium or discount on the shares sold

Q. WHAT HAS BEEN THE HISTORY OF RETAINED EARNINGS BY DELTA?

A. Lines 1, 2 and 3 of Exhibit_____(CWK-3) show the record of Delta's dividends and earnings per share and the consequent earnings retention ratios since 1999. The exhibit reveals that except for the very poor earnings year 1999, the earnings retention ratio has remained in a rather tight range between .192 and .224.

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6 If the Company is earning its required rate of return, the market value of its stock should exceed the book value. That is because investors do not require that the full rate of return be earned in the current period, only that the prospects for future earnings correspond to their growth expectations.

Q. WHAT RETENTION RATIO DO YOU PROPOSE TO USE TO CALCULATE THE BOOK GROWTH POTENTIAL OF DELTA'S STOCK?

A. It appears that the Company has adopted a policy of retaining approximately 20 percent of its annual earnings. I assume that this policy will continue into the future.

Q. WHAT IS THE RECORD OF RETURN TO THE BOOK VALUE PER SHARE FOR DELTA?

A. On lines 4 through 7, I calculate the return on book value per share for Delta in each year since 1999. The two "down" years are 1999 and 2003, both of which prompted rate cases. During the intervening years, Delta did not seek rate relief, so I assume it was satisfied with the earnings it experienced in those years. Those earnings averaged approximately 11 percent. For purposes of this exercise, I use 11 percent as the forecast maximum earnings level for equity capital.

Q. WHAT DO YOU FORECAST AS THE EARNINGS RETENTION GROWTH FOR DELTA?

A. With retained earnings of 20 percent and an 11 percent annual return to book equity, the growth that can be expected from retained earnings is 2.2 percent annually.

Q. WHAT IS THE HISTORY OF BOOK VALUE GROWTH FROM PREMIUMS ON NEW SHARES OF STOCK?

A. That history is displayed on lines 9 and 10 of Exhibit_____(CWK-3). During each of the years 1999 through 2002, the premium on new shares issued through employee stock purchase plans and dividend reinvestment plans averaged about $650,000 annually, yielding an increase in per-share book value of approximately two percent. In 2003, the Company sold 600,000 at a premium over book value of $12.5 million. This resulted in an increase in the book value of the existing shares of 28.6 percent. Averaged over the five year period, 1999-2003, the increase in book value per share from issuing new shares was 7.34 percent annually.

Q. WHAT IS THE LIKELY FUTURE GROWTH IN PER-SHARE VALUE DUE TO NEW STOCK ISSUES?

A. The 7.34 percent average for the past five years is not particularly relevant as an indicator of future growth from new stock issues, as it was heavily influenced by the sale of 600,000 new shares in 2003. However, it would be inappropriate to assume that the routine two percent growth is representative of the future either. Such an assumption presupposes that the Company would never conduct another stock sale such as it did in 2003. For this reason, I have assumed that investors would expect an annual growth in book value from new share issues in the range of 3 to 4 percent. Admittedly, this is a judgment call, but I know of no other way to quantify this effect.

Q. WHAT IS THE DCF RETURN USING THE BOOK VALUE GROWTH MODEL?

A. Exhibit_____(CWK-3) shows that the DCF return using the book value growth model is in the range of 10.1 to 11.1 percent.

CAPITAL ASSET PRICING MODEL

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model ("CAPM") employs a measure called "beta," which tests the covariance of the stock at issue with that of the overall market, to assess the relative risk of the stock against the market. As conventionally used by rate-of-return analysts, the beta is assumed to measure the cost of the company's equity on a continuum between the average required return of the overall equity market and a risk-free return.

The CAPM formula, including a size premium as suggested in the academic literature, is as follows:

$$k = R_f + \beta(R_m - R_f) + SP$$

Where

k = the prospective market cost of common equity for a specific investment
R_f = the "risk-free" rate of return
β = the company-specific beta
R_m = the overall stock market return on stocks for the prospective period
SP = a size premium or discount for the market capitalization of the firm relative to the overall market.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPM?

A. I believe that CAPM has value in assessing the relative risk of different stocks and portfolios of stocks. It can therefore be useful in checking the results of other, more reliable methods of measuring equity return, such as the DCF procedure. However, because of the extensive requirement for judgment in selecting each of the inputs, I question its value in directly estimating a return to equity.

Q. WHAT JUDGMENT IS REQUIRED FOR THE FIRST INPUT, β, OR BETA?

A As noted, beta measures the degree of covariance of the stock with that of the market overall. But neither the fluctuations of the stock nor those of the market are constant, or even be consistent with each other over any extended period of time. As a result, there are as many estimates of beta for a given company as there are analysts making the measurement.

Q. WHAT JUDGMENT IS REQUIRED TO IN SELECTING THE INPUT R_f, THE RISK-FREE RATE OF RETURN?

A. There is general consensus that yields to U.S. government securities are risk-free in the sense that they are free from the risk of default. The difficulty is that there are quite a number of U.S. government securities of differing maturities that have very different yields. Most utility-sponsored rate-of-return witnesses assert that because stocks exist in perpetuity, the yield of long-term government bonds is the appropriate risk-free rate. The difficulty with this argument is that long-term bonds are not free from risk. To the contrary, they carry a substantial risk that inflation will erode their eventual value at maturity. Stocks do no bear this inflation risk because generally the stock market rises when inflation rises. Moreover, while equity investment may exist in perpetuity, few investors buy stocks with the intention of holding them in perpetuity. To the contrary, the NYSE has an annual turnover rate of over 100 percent, suggesting that the average holding time of a share of stock is about a year.

Q. WHAT JUDGMENT IS REQUIRED IN SELECTING THE INPUT R_m, THE RETURN TO THE OVERAL MARKET?

A The complexities and uncertainties associated with measuring the return to equity of an individual company are not reduced when the object of the analysis is expanded to the entire market for equities. Generally, CAPM analysts use one of two procedures. Either they perform simplistic DCFs for a wide variety of stocks, in which case why not use the same DCF for the stock under study? Or they use the historical return to market equities, which assumes, totally unrealistically, that the investors in the equity markets during the period under study actually realized the return that they were expecting. This approach tells us nothing about future expectations from the market.

Q. WHAT JUDGMENT IS REQUIRED IN SELECTING THE INPUT SP, THE SIZE PREMIUM OR DISCOUNT?

A. I have already discussed this problem. While there is no question that small companies, in general, are more risky than large companies, it is by no means certain that this generalization can be applied to a franchised gas distribution company such as Delta. Furthermore, the selection of the size premium (or discount, for a large company) is complicated by the fact that the University of Chicago has developed two schedules of size premiums, one based on geometric means, the other based on arithmetic means, and that both schedules can be expressed using decile averages or quartile averages.

Q. HAVE YOU ATTEMPTED TO APPLY THE CAPM TO DELTA?

A. Yes, although this attempt has involved a considerable application of judgment in the selection of inputs. The results of this effort are set forth in Exhibit _____(CWK-4).

Q. WHAT CAPM INPUTS DID YOU SELECT?

A. In determining the risk-free rate of return, I relied on the NYSE's evidence that the shares on that exchange experienced a 106 percent turnover during the 12 months ending May 2004 (line 1). This implies an average holding time, or "investment horizon" of one year (line 2). I therefore selected the one-year Treasury fixed maturity bond rate as the risk-free rate (line 3).

I then constructed a Discounted Cash Flow return for the entire market based on Value Line's report that the median dividend yield for the dividend-paying stocks among the 1700 companies that it follows is 1.7 percent (line 4), and that the median appreciation potential during the next three to five years is 50 percent (line 5). This latter value translates into a compound annual growth rate of 10.7 percent (line 6). The overall market return prospectively is therefore assumed to be 12.7 percent (line 7), and the risk premium over the risk-free rate is 10.6 percent (line 8).

I used Value Line's most recent calculation of Delta's beta of .50 (line 9) to set Delta's risk premium at 5.3 percent (line 10). When added to the risk free rate, Delta's CAPM return, without a size adjustment, is 7.1 percent (line 11). I then added the difference between the geometric means of the micro-cap stock returns and the overall market from the University of Chicago study (as reported by Ibbotson Associates) to derive a size premium for Delta of 2.6 percent (line 13).

Based on these highly judgmental inputs, I derive a CAPM return for Delta of 9.7 percent.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS WITH REGARD TO DELTA'S COST OF EQUITY CAPITAL?

A. Yes. I can summarize my findings in declining order of reliability:

- DCF of peer group companies using analysts' forecasts of "g" 9.4% - 10.8%
- DCF of Delta using book value growth model 10.1% – 11.1%
- Capital Asset Pricing Model 9.7%
- DCF using Value Line's forecast for Delta 8.9%

Q. WHAT DO YOU DERIVE AS THE RATE OF RETURN FOR DELTA'S EQUITY CAPITAL?

A. I have assigned weightings to these results, and I have used the mid-points of the range values, as follows:

Method	Weighting	Result	Weighted Result
DCF Peer Group	5	10.1%	50.5
DCF Book Value Growth	3	10.6%	31.8
Capital Asset Pricing Model	2	9.7%	19.4
DCF Delta Value Line Forecast	1	8.9%	8.9
Total	11		110.6
Average			**10.05%**

OVERALL RATE OF RETURN

Q. WHAT IS THE OVERALL COST OF CAPITAL USING YOUR RECOMMENDED RATE OF RETURN TO EQUITY?

A. Using the capital structure and cost of debt shown in Schedule 9 under Tab 27 of the Filing Requirements, I calculated the overall return to capital as 7.64 percent, as follows:

	Percentage	Cost	Weighted Cost
Equity	37.15%	10.05%	3.734%
Long-term Debt	47.51%	7.422%	3.526%
Short-term Debt	15.35%	2.478%	0.380%
Total	100.00%		7.640%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

In the Matter of:

AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	)))	**CASE NO: 2004-00067**

AFFIDAVIT

Comes the affiant, Charles W. King, and being duly sworn states that the foregoing testimony and attached schedules were prepared by him or under his direction and supervision and are, to the best of his information and belief, true and correct.

____

State/Commonwealth of District of Columbia,) SS.
County of Washington

Subscribed and sworn to before me by the Affiant Charles W. King this the 1st day of July, 2004.

Angel L. Finch
Notary Public, State at Large
My Commission Expires: 3-14-06

Retail Gas Distribution Companies
"Classic" Discounted Cash Flow Analysis

Company	A Value Line Dividend 2004	B Value Line Dividend 2005	C Average Dividend	D Stock Price 2004 High	E Stock Price 2004 Low	F Stock Price Current	G Average	H Dividend Yield	I Value Line Growth Forecast	J Indicated DCF Return
Delta Natural Gas (000)	1.20	1.22	1.21	27.78	23.00	23.31	24.70	4.9%	3.0%	7.9%
AGL Resources (2002)	1.12	1.12	1.12	30.60	27.90	28.85	29.12	3.8%	6.5%	10.3%
Atmos Energy	1.22	1.24	1.23	27.00	24.30	24.98	25.43	4.8%	5.0%	9.8%
Cascade Natural Gas	0.96	0.96	0.96	23.00	21.00	21.52	21.84	4.4%	9.0%	13.4%
Energen	0.75	0.77	0.76	44.70	40.70	46.95	44.12	1.7%	4.2%	5.9%
KeySpan	1.78	1.78	1.78	38.60	35.70	36.04	36.78	4.8%	6.5%	11.3%
Laclede Group	1.36	1.36	1.36	31.90	28.30	27.06	29.09	4.7%	5.0%	9.7%
New Jersey Resources	1.28	1.32	1.30	40.00	36.80	39.80	38.87	3.3%	8.0%	11.3%
NICOR	1.86	1.86	1.86	37.40	32.50	34.77	34.89	5.3%	0.5%	5.8%
Northwest Natural Gas	1.30	1.33	1.32	33.00	30.00	30.20	31.07	4.2%	4.5%	8.7%
People's Energy	2.16	2.20	2.18	46.00	41.40	42.38	43.26	5.0%	4.0%	9.0%
Piedmont Natural Gas	1.72	1.78	1.75	43.80	40.40	42.75	42.32	4.1%	7.5%	11.6%
South Jersey Industries	1.62	1.67	1.65	42.30	40.20	43.30	41.93	3.9%	6.0%	9.9%
Southwest Gas	0.82	0.82	0.82	24.10	21.50	23.40	23.00	3.6%	10.5%	14.1%
UGI Corp	1.23	1.33	1.28	34.30	29.80	31.45	31.85	4.0%	7.5%	11.5%
WGL Holdings	1.30	1.30	1.30	30.10	27.20	29.21	28.84	4.5%	3.5%	8.0%
Average										**9.4%**
Mid Cap/Micro Cap Adder										1.4%
Adjusted Average										**10.8%**

Gas Distribution Utilities
Capital Structures
(Dollars in Millions)

9/30/2003	A Short-term Debt	B Long-term Debt	C Preferred Stock	D Common Equity	E Capital Including S-T Debt	F Equity/ Total Capital	G Equity/ Capital - S-T Debt
AGL Resources	306.4	956.1		710.1	1,972.6	36.0%	42.6%
Atmos Energy	118.6	863.9		857.5	1,840.0	46.6%	49.8%
Cascade Natural Gas	3.8	142.9		112.6	259.3	43.4%	44.1%
Energen	11.0	552.8		699.0	1,262.8	55.4%	55.8%
Energy West	6.1	14.8		15.3	36.2	42.3%	50.8%
KeySpan	481.9	5,611.4	83.6	3,745.5	9,922.4	37.7%	39.7%
Laclede Group	218.2	259.6	1.3	345.3	824.4	41.9%	57.0%
New Jersey Resources	185.8	257.9		418.9	862.6	48.6%	61.9%
NICOR	575.0	495.1	1.8	756.4	1,828.3	41.4%	60.4%
Northwest Natural Gas	85.2	500.3		506.3	1,091.8	46.4%	50.3%
People's Energy	55.9	744.4		862.6	1,662.9	51.9%	53.7%
Piedmont National	555.1	460.0		630.2	1,645.3	38.3%	57.8%
RGC Resources	13.0	30.2		33.9	77.1	43.9%	52.9%
Southern Union	251.5	1,611.7		1,176.5	3,039.7	38.7%	42.2%
South Jersey Industries	112.8	308.8		299.7	721.3	41.5%	49.3%
Southwest Gas	52.0	1,221.2		630.5	1,903.7	33.1%	34.0%
UGI Corp	56.6	1,158.5		569.8	1,784.9	31.9%	33.0%
WGL Holdings	166.7	636.7		842.7	1,646.1	51.2%	57.0%
Average						**42.8%**	**49.6%**
Delta Natural Gas ($000)							
September 30, 2003	17,708	54,824		44,030	116,562	**37.8%**	**44.5%**
December 31,2003	19,358	53,174		44,030	116,562	**37.8%**	**45.3%**
March 30, 2004	7,658	53,133		47,080	107,871	**43.6%**	**47.0%**

Delta Natural Gas Company
Book Value Growth Model - DCF Return

		1999	2000	2001	2002	2003	Historical Average	Forecast
1	Dividend per Share	1.14	1.14	1.14	1.16	1.18		
2	Earnings per Share	0.90	1.42	1.47	1.45	1.46		
3	Earnings Retention Ratio	(0.267)	0.197	0.224	0.200	0.192	0.109	0.200
4	Shareholders' Equity	29,912,007	31,297,418	32,754,560	34,182,277	45,892,597		
5	No of Shares Outstanding	2,394,181	2,433,397	2,477,983	2,513,804	2,641,829		
6	Book Value per Share	12.49	12.86	13.22	13.60	17.37		
7	Return on Book Equity	7.20%	11.04%	11.12%	10.66%	8.40%	9.69%	11.00%
8	Growth from Retained Earnings						1.1%	2.2%
9	Premium on new shares issued	641,067	652,801	618,313	673,022	13,132,103		
10	Per-share growth from premiums	2.14%	2.09%	1.89%	1.97%	28.61%	7.34%	3.0%-4.0%
11	Growth Potential per Share						8.40%	5.2% - 6.2%
12	Dividend Yield							4.9%
13	DCF Return							**10.1%- 11.1%**

Delta Natural Gas Company
Capital Asset Pricing Model Rate of Return

		Source	
1	NYSE Turnover Rate, 12 Mos. Ending May 2004	www.nyse.com/marketinfo	106%
2	Average Holding Time	Based on Line 1	1 year
3	Yield on 1-year Treasury Bonds, May 2004	www.federalreserve.gov/releases, H15	1.78%
4	Value Line Median Esitmate Dividend Yield, Next 12 Mos.	www.valueline.com/secure	1.7%
5	Value Line Median Appreciation Potential 3 to 5 Years Hence	"	50.0%
6	Value Line Apreciation Potential Annualized at 4 Years	Line 5 to 4th Root	10.7%
7	Total Market DCF Return	Line 4 + Line 6	12.4%
8	CAPM Market Risk Premium	Line 7- Line 3	10.6%
9	Delta's beta as per Value Line	www.valuline.com	0.50
10	Delta's Risk Premium	Line 8*Line 9	5.3%
11	Delta's Raw CAPM Return	Line 3+Line 10	7.1%
12	Average Return 1926 to 2003, NYSE/AMEX/NASDAQ	Ibbotson Assoc, 2004 Yearbook p.128	10.1%
13	Micro-cap Return 1926 to 2003, NYSE/AMEX/NASDAQ	"	12.7%
13	Small-size Premium	Line 13-Line 12	2.6%
14	Delta's Size-Adjusted CAPM Return	Line 11+Line 13	9.7%

Charles W. King

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation. Mr. King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

CHARLES W. KING
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Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission	U-1345-I	Arizona Public Service Co.	December 16, 1980
	Arizona Retailers Association	U-1345-II	Arizona Public Service Co.	January 15, 1981
CA	California Retailers Association	57666	Pacific Gas & Electric Co.	March 6, 1978
	California Retailers Association	57602	Southern California Edison	April 25, 1978
	California Retailers Association	59351	Pacific Gas & Electric Co.	June 12, 1981
	California Retailers & California Manufacturers	59351	Southern California Edison	May 20, 1982
	California Retailers Association	61138	Southern California Edison	May 28, 1982
CO	U. S. Department of Defense	I&S 1100	Colorado Springs (Elec)	June 14, 1977
	J.C. Penny Company	5693	All Electric Utilities	March 8, 1978
	U.S. Department of Defense	I&S 1339	Colorado Springs DPU (Gas)	October 18, 1979
	U. S. Department of Defense	I&S 1540	Colorado Springs DPU (Gas)	February 9, 1982
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Gas)	September 30, 1984
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 6, 1985
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	May 19, 1986
	U.S. Department of Defense	C. Council	Colorado Springs DPU (Elec)	June 30, 1987
CT	Retailers Merchants Association	72-0204	Various Electric Utilities	July 22, 1976
	Division of Consumer Counsel	76-0604,5	CL&P and HELCO	November 10, 1977
	Public Utilities Control Auto	78-0303	Bridgeport Hydraulic Co.	(none)
	Division of Consumer Counsel	80-0403,4	CL&P and HELCO	August 11, 1980
	Division of Consumer Counsel	81-0413	United Illuminating Company	July 20, 1981
	Division of Consumer Counsel	81-0602,4	CL&P and HELCO	October 5, 1981
	Division of Consumer Counsel	82-0701	CL&P	September 28, 1982
	Coalition of Hotels, Alloys & Retailers	85-10-22	CL&P	(none)
	Coalition of Hotels, Alloys & Retailers	87-07-01	CL&P	April 25, 1988

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
	D.C. People's Counsel	989	Washington Gas Light Company	May 22, 2002
	D.C. People's Counsel	1016	Washington Gas Light Company	September 23, 2003
DE	Delaware PSC Staff	94-164	Artesian Water Company	Filed March 10, 1995
	Delaware PSC Staff	94-149	Wilmington Surburban Water Company	March 10, 1995
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
	Georgia Public Service Commission	14311-U	Atlanta Gas Light Company	April 8, 2002
	Georgia Public Service Commission	17066-U	Georgia Power Company	July 31, 2003
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983
IL	Illinois Retail Merchants Association ("IRMA"/ Chicago Bldg. Mgrs. Association ("CBMA")	76-0698	Commonwealth Edison	June 22, 1977
	IRMA/CBMA	76-0568	All Eletric Utilities	(none)
	IRMA/CBMA	80-0546	Commonwealth Edison	March 5, 1981
	IRMA/CBMA	82-0026	Commonwealth Edison	July 22, 1982
	IRMA/CBMA	83-0537	Commonwealth Edison	March 19, 1984
	IRMA/CBMA	87-0427	Commonwealth Edison	March/April 22, 1988
	IRMA/CBMA	90-0169	Commonwealth Edison	October 29, 1990
	City of O'Fallon, IL	02-0690	Illinois-American Water Company	Filed Feb.5, Apr.11,2003
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penny Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
	Attorney General of Kentucky	2002-145	Columbia Gas of Kentucky	Filed August 8, 2002
	Attorney General of Kentucky	2003-252	Union Heat Light & Power Co.	September 30, 2003

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Client	Case Number	Utility	Date of Cross-Examination
	Electric, Gas, Water Utility Cases			
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977
	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
	Giant Foods, Inc.	8855	Baltimore Gas & Electric Company	January 8, 2003
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
	Michigan Attorney General	U-13380	Consumers Energy Company	September 9, 2002
	Michigan Attorney General	U-13715	Consumers Energy Company	April 24, 2003
	Michigan Attorney General	U-13808	Detroit Edison Company	Dec 12, 2003; Jan 30, Mar 5, March 26, 2004
	Michigan Attorney General			

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission North Dakota Public Service Commission North Dakota Public Service Commission North Dakota Public Service Commission North Dakota Public Service Commission	PU-400-00-521 PU-399-01-786 PU-399-02-183 PU-399-02-183 PU-399-03-296	Xcel Energy, Inc. Montana-Dakota Utilities (Electric) Montana-Dakota Utilities (Gas) Montana-Dakota Utilities (Gas Depr.) Montana-Dakota Utilities (Electric)	April 20, 2001 February 25, 2002 October 7, 2002 Filed April 7, 2003 Filed October 15, 2003
NH	Business & Industry Association of N.H. Business & Industry Association of N.H. Business & Industry Association of N.H.	79-187-II 80-260 82-333	Public Service of N.H. Public Service of N.H. Public Service of N.H.	February 6, 1981 February 5, 1981 November 2, 1983
NJ	N.J. Retail Merchants Association Department of Public Advocate Resorts International Hotel, Inc. Dept. of Public Advocate Dept. of Public Advocate Dover Township Fire Chiefs	803-151 815-459 8011-827 822-116 355-87 88-080967	All New Jersey Utilities N.J. Natural Gas Company Atlantic City Sewerage Co. Atlantic City Electric Co. Elizabethtown Gas Tom's River Water Company	March 31, 1981 (none) (none) August 11, 1982 June 9, 1987 February 22, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
NY	N.Y. Council of Retail Merchants	26806	All Electric Utilities	February 3, 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa. Transp. Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn. Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn. Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
	Pennsylvania Office of Consumer Advocate	R-00016339	Pennsylvania-American Water Co.	September 19, 2001
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989
UT	Div. Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
VA	Consumer Congress of Virginia	19426	Virginia Electric Power Company	July 1, 1975
	Consumer Congress of Virginia	19960	Virginia Electric Power Company	September 19, 1978
	Va. Business Committee on Energy	PUE 7900012	Virginia Electric Power Company	February 25, 1981
	Virginia Pipe Trades Council	PUE 8900051	Old Dominion Electric Corp. &	October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
ID	U.S. Department of Energy U.S. Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co. Mountain Bell Telephone Co.	May 16, 1983 March 6, 1984
IL	Illinois Aalarm Companies Attorney Generaal of Illinois GTE Sprint Communications Co. Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr. Repr. 166.856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
KY	Kentucky Cable Telecommunications Assn. Kentucky Cable Telecommunications Assn.	2000-414 2000-39	Blue Grass Energy Cooperative Cumberlant Valley Electric, Inc.	January 11, 2001 January 11, 2001
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co. AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co. U.S. Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co.	August 5, 1983 (none)

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Client	Case Number	Utility	Date of Cross-Examination
	Telecommunications Cases			
		Case		
MO	GTE Sprint Communications Co.	TR83-253	Southwestern Bell Tel. Co.	September 5, 1983
	Federal Executive Agencies	TC-89-14	Southwestern Bell Tel. Co.	(none)
	Federal Executive Agencies	TO-89-56	Southwestern Bell Tel. Co.	November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990
NJ	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	Mar-79
	Department of Public Advocate	815-458	N.J. Bell Telephone Company	October 15, 1981
	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	March 1, 1982
	Department of Public Advocate	Depr.Repr.	N.J. Bell Telephone Company	February 1, 1985
	Department of Public Advocate	T092030358	N.J. Bell Telephone Company	September 30, 1992
NM	New Mexico Corporation Commission	1032	Mountain Bell Telephone Co.	November 14, 1983
	New Mexico Corporation Commission	86-151-TC	General Telephone of Southwest	February 5, 1987
NV	Prime Cable of Las Vegas	95-8034/8035	Central Telephone - NV	Filed November 22, 1995
	Prime Cable of Las Vegas	96-9035	Sprint/Centel, Nevada Bell	June 2, 1997
NY	Holmes Protection, Inc.	27350	New York Telephone Company	October 17, 1978
	Holmes Protection, Inc.	27469	New York Telephone Company	May 17, 1979
	5 Alarm Companies	27710	New York Telephone Company	July 24, 1980
	GTE Sprint Communications Co.	28425	All Telephone Companies	July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate	Depr.Repr.	Southern Bell	July 1, 1986
	Office of Consumer Advocate	86-511-C	Southern Bell	December 11, 1986
	Office of Consumer Advocate	86-541-C	General Telephone of South	April 8, 1987
	Office of Consumer Advocate	Depr.Repr.	Southern Bell	July 10, 1989
	Office of Consumer Advocate	89-180-C	ALLTEL of South Carolina	September 26, 1989

CHARLES W. KING
Appearances before State Regulatory Agencies

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696	C&P Telephone Company	October 6, 1976
		PUC 890014	All Telephone Companies	February 13, 1989
VI	V.I. Department of Commerce	205	Virgin Islands Telephone Co.	April 29, 1980
	V.I. Public Service Commission	341	Virgin Islands Telephone Co.	March 20, 1991
WA	U.S. Department of Defense	U-72-39	Pacific Northwest Bell	1973
	U.S. Department of Defense	U-87-796-T	Pacific Northwest Bell	December 20, 1983
	U.S. Department of Defense	U-88-20524	Pacific Northwest Bell	November 8, 1988
	U.S. Department of Defense	U-89-2698-F	US West Communications	November 28, 1989
	WA Attorney General/TRACER	UT-940641	US West Communications	Filed October 14, 1994
	U.S. Department of Defense	UT-941464	US West Communications	June 22, 1995
	U.S. Department of Defense		US West Communications	January 22, 1996
	WA Attorney General/TRACER	UT-951425	US West Communications	Filed June 23, 1997
	WA Attorney General/TRACER	UT-961632	GTE Northwest, Inc	July 29, 1997
	U.S. Department of Defense	UT-021120	Qwest Communications	May 22, 2003
WI	GTE Sprint	6720-TR-38	All Telephone Companies	October 20, 1983
	Wisconsin Consumers Utility Board	2055-TR-102	CenturyTel of Central Wisconsin	June 26, 2002
	Wisconsin Consumers Utility Board	5846-TR-102	Telephone USA, LCC	June 26, 2002

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeornautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

CASE NO. 2004-00067

AN ADJUSTMENT OF THE RATES OF
DELTA NATURAL GAS COMPANY, INC.

TESTIMONY OF

DAVID H. BROWN KINLOCH

On Behalf of

THE OFFICE OF THE ATTORNEY GENERAL
FOR THE COMMONWEALTH OF KENTUCKY

JUNE 2004

Soft Energy Associates • 414 South Wenzel Street • Louisville, KY 40204 • 502-589-0975

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

* * * * *

In the Matter of:

AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	)) CASE NO. 2004-00067)

TESTIMONY OF DAVID H. BROWN KINLOCH

Q1: PLEASE STATE YOUR NAME AND ADDRESS.

A1: My name is David H. Brown Kinloch and my business address is Soft Energy Associates, 414 S. Wenzel Street, Louisville, KY 40204.

Q2: FOR WHOM HAVE YOU PREPARED TESTIMONY?

A2: I have prepared this testimony for the Office of the Attorney General for the Commonwealth of Kentucky.

Q3: PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A3: I have received two master's degrees from Rensselaer Polytechnic Institute (RPI) in Troy, New York. I also received two undergraduate degrees from the same school. My master's degrees are a Master of Engineering in Mechanical Engineering and a Master of Science in Science, Technology and Values, received in 1979 and 1981 respectively. My undergraduate degrees are in Mechanical Engineering and Philosophy. Much of my master's work included preparing Electric Generation Planning studies for the Center for Technology Assessment at Rensselaer. From this work I published two technical papers with IEEE Power Generation Division, and was a contributing author on two others. I also did work on New York State's first Energy Masterplan, one of the first comprehensive long-term planning studies in the nation.

Q4: HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THIS COMMISSION?

A4: Yes, I testified in the following rate cases: Louisville Gas & Electric Co. Case No. 2003-00433, Case No. 2000-00080, Case No. 90-158, Case No. 10064, and Case No. 9824; Kentucky Utilities Co. Case No. 2003-00434, Kentucky Power Co. Case No. 91-066; Union Light Heat and Power Co. Case No. 92-346 and Case No. 91-370; Big Rivers Electric Corp. Case No. 9613 and Case No. 97-204; Delta Natural Gas Co. Case No. 97-066; Western Kentucky Gas Co. 95-010; East Kentucky Power Cooperative Case No. 94-336; Clark RECC Case No. 92-219; Jackson Purchase ECC Case No. 97-224; Meade County RECC Case No. 97-209; Green River EC Case No. 97-219, Henderson Union ECC Case No. 97-220, Kenergy Corp. Case No. 2003-00165 and Licking Valley RECC Case No. 98-321. I also presented testimony in cases involving each of East Kentucky Power's

Cooperatives in the pass-through of rate reductions associated with Case No. 94-336. I also testified in the Commission's reviews of LG&E's Trimble County power plant, Case No. 9934 and Case No. 9242, and the rate impact of the 25% disallowance of that project, Case No. 10320. In addition, I presented testimony in the Certificate of Convenience and Necessity cases for Kentucky Utilities, Case No. 91-115, LG&E and KU, Case No. 2002-00029, and East Kentucky Power, Case No. 92-112, Case No. 2000-056, Case No. 2000-079, Case No. 2001-053 and Case No. 2003-030. I have also testified in Fuel Adjustment Clause cases involving Louisville Gas and Electric, Case No. 96-524, and Kentucky Utilities, Case No. 96-523; and in Environmental Surcharge cases involving Kentucky Power, Case No. 96-489; Kentucky Utilities, Case No. 93-465; and Louisville Gas and Electric, Case No. 94-332. Other cases in which I presented testimony include the Kentucky Utilities' Coal Litigation Refund case, Case No. 93-113; the Big Rivers' sale of peaking capacity to Hoosier Energy case, Case No. 93-163; the Joint Application case with LG&E to establish Demand Side Management programs, Case No. 93-150; and the Louisville Gas and Electric and Kentucky Utilities merger case, Case No. 97-300, the LG&E Energy and PowerGen merger case, Case No. 2000-095; a Union Light, Heat and Power refund case, Case No. 2000-426: and the Union Light, Heat and Power generation acquisition case, Case No. 2003-0052.

Q5: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A5: The Office of the Attorney General asked me to review the application to adjust rates filed by Delta Natural Gas Company, Inc. (Delta) in this case. Specifically, I have reviewed the Cost of Service and Rate Design portion of the application. In my testimony, I will point out problems with the Delta application in four specific areas: 1) the Cost of Service Study, 2) the proposed monthly customer charges, 3) the proposed increase in the reconnection charge, and 4) the proposed GTIR&D tariff rider.

COST OF SERVICE STUDY

Q6: IN SUPPORT OF DELTA'S APPLICATION TO ADJUST GAS RATES, IT FILED A COST OF SERVICE STUDY BASED ON A TEST YEAR ENDING DECEMBER 31, 2003. DO YOU SEE ANY PROBLEMS WITH THIS COST OF SERVICE STUDY FILED BY DELTA?

A6: Yes. While in general Mr. Seelye did a rather good job with the Cost of Service Study he prepared for Delta in this case, there is one significant problem with this study that should be corrected. The use of a weighted least squares zero intercept analysis to divide distribution mains into customer and demand components produced some questionable results.

Q7: WHAT LEADS YOU TO BELIEVE THAT THE DELTA ZERO INTERCEPT RESULTS ARE QUESTIONABLE?

A7: There are a number of things about the Delta zero intercept results that raise questions. First there are the overall results themselves. The Delta zero intercept analysis calculated that over half of main costs (56.54%) should be classified as customer related. Compared to similar calculations done on other utilities this customer portion is very high. A customer portion around 20% is more typical, as was used as an the example in the NARUC Gas Distribution Rate Design Manual. The customer portion is the fixed portion of the gas main that would have to be there no matter what size gas main was installed. With such a large customer portion calculated for Delta, it would suggest that gas main costs vary little with size.

A second thing that makes the Delta results questionable is the fact that the zero intercept size of mains, the size of a zero inch main, was calculated to be about \$3 per foot. This appears to be very high since two-thirds, 4 out of the 6, of the smaller size pipes - sizes below 4 inches - have costs significantly below this calculated zero size cost. In fact half, 3 of 6, pipe sizes are less than half the cost of the calculated zero inch size (\$1.21, \$1.22, and \$1.32 per foot). And looking at all pipe sizes, 4 out of a total of 11, or 36% of all pipes have costs below the calculated zero-inch size. This makes the calculated zero-inch size seem highly questionable.

Another check of the validity of the zero intercept result is to review the quality of the line that was calculated to fit the pipe data points. On page 1 of 4 of Seelye Exhibit 5, the R-Square value of the plot fit was calculated to be 0.838, with 1.0 representing a perfect fit and 0 representing no correlation at all. In Exhibit DHBK-1, I have included the graph from Seelye Exhibit 5, page 4 of 4, which provides a visual representation of how well the straight line calculated by Mr. Seelye with the weighted least squares analysis fits. By comparison, in Exhibit DHBK-2, I have included the same results graph done by Mr. Seelye using the same methodology in LG&E Gas Case No. 2000-080 (taken from Delta's response to the AG's First Data Request, Item 157, page 2 of 21).

The graph from Case No. 2000-080 shows the data points lining up closely with the zero intercept line, as can be seen with an associated R-Square value of 0.989, thus there is a very strong correlation. In this analysis all pipe cost per foot values were above the zero intercept zero-inch cost calculated. This analysis also produced a customer portion of 17.30% which is close to the common 20% range expected.

The Delta graph in this case, shown in Exhibit DHBK-1, is quite different. Few of the data points are near the zero intercept line. The one exception is the 2" plastic pipe point which is right on the line. Since the 2" plastic pipe makes up over half of all the investment in mains, being right on the line in a weighted analysis helps to explain why the low R-Squared figure is as high as it is.

Q8: ARE THESE QUESTIONABLE RESULTS A SIGN THAT MR. SEELYE MADE AN ERROR IN HIS WEIGHTED LEAST SQUARES ANALYSIS?

A8: No. I reviewed Mr. Seelye's calculations and it appears that he did them properly. The problem is not the calculation but rather trying to apply this methodology to such an irregular data set. The methodology provided the best line fit it could, considering how irregular the starting data is.

Q9: SINCE THE METHODOLOGY PROPERLY USED BY MR. SEELYE IN THIS CASE PRODUCED RESULTS THAT ARE QUESTIONABLE, WOULD ANOTHER METHODOLOGY SUCH AS THE MINIMUM SIZE ANALYSIS PRODUCE MORE RELIABLE RESULTS?

A9: Not necessarily. A minimum size analysis would have similar difficulties due to the irregular data. As Mr. Seelye pointed our in his testimony, a minimum size analysis would require substantial amounts of subjectivity. In this Delta case, there are two minimum size (1.5-inch) pipe types with one having three times the cost per foot as the other. Further complicating the matter is that there are three other larger pipes with lower costs per foot than the 1.5-inch minimum size. It is subjective as to what would be used as the minimum: 1) the lower cost minimum size, 2) a weighted average of the minimum size, or 3) the pipe with the minimum cost per foot. The irregular nature of the pipe data makes selection of the minimum pipe a difficult task.

Q10: YOU KEEP REFERRING TO IRREGULAR DATA COMPLICATING THE ANALYSIS. HOW IS THE DATA IRREGULAR?

A10: The Delta pipe data is irregular in a number of ways. First, as compared to the sample LG&E pipe data in Exhibit DHBK-2, the Delta data is spread all over the graph instead of bunching up in a more orderly manner, rising in cost as pipe sizes increase. Second, the smallest pipes (1.5-inches) have higher costs per foot than larger pipes like the 3-inch pipes. Inputs like this run counter to the assumption at the heart of both the zero intercept and minimum size analysis that costs decrease as pipe sizes decrease.

The Delta main pipe data set is further complicated by the fact that most of the investment in mains have been made in just two pipe type:- the 2-inch plastic main and the 4-inch plastic main. These two mains alone account for almost four-fifths of all of Delta's investment in mains (2-inch plastic = 51.2% and 4-inch plastic = 27.5%). No other main comes anywhere near this amount of investment with all other main sizes consisting of single digit percentage investment levels. While all the other main sizes provide points for creating a graph, the analysis should be focused on these two pipes that make up most of the system.

Q11: WHAT TYPE OF ALTERNATIVE ANALYSIS WOULD YOU PROPOSE?

A11: Since the use of all the irregular data produces very questionable results, and Delta's investment in mains is primarily in the 2-inch and 4-inch plastic mains, I would recommend using a zero intercept analysis that is based on these two pipes that make up almost 80% of all of Delta's investment in mains. In Exhibit DHBK-3, I have performed a zero intercept analysis limiting the data input to these two sizes that constitute most of Delta's investment in mains. The results of this analysis is shown on page 1 of 3 of this exhibit. With this analysis, all of Delta's pipe costs per foot are above the zero intercept cost per foot, as was achieved by Mr. Seelye in Case No. 2000-080 (see Exhibit DHBK-2). The R-Square is 1.0, or a perfect fit, since only two data points are being used. And the resulting portion of the mains assigned to the customer component is 20.10%, which is in the range that is typical. Thus, because of the highly irregular nature of the Delta input data, limiting the zero intercept analysis to the primary mains produces much more reliable results than those produced by Delta when the irregular minor pipe sizes were included.

Q12: IF THE MORE RELIABLE RESULTS FROM THE PRIMARY MAINS ZERO INTERCEPT ANALYSIS ARE INCLUDED IN DELTA'S COST OF SERVICE STUDY, HOW ARE THE RESULTS AFFECTED?

A12: In Exhibit DHBK-4, I have included the demand and customer main allocations generated in the primary mains zero intercept analysis done in Exhibit DHBK-3. This change in the distribution main cost allocation is the only change I made to the Functional Assignment and Classification of Costs calculations done in Seelye Exhibit 1. These changes are then carried forward into the Allocation of Costs to Customer Classes in Exhibit DHBK-5. In this exhibit, I have made no changes to the formulas in Seelye Exhibit 2; the only difference is the changes caused by the corrected distribution main allocations in Exhibit DHBK-2. The impact of this change is illustrated by the differences in the "Actual" present Rates of Return by class, before the rate increase is applied:

CLASS	DELTA RETURN	AG CORRECTED RETURN
Residential	3.83%	4.94%
Small Non-Residential	7.87%	7.46%
Large Non-Residential	8.07%	5.71%
Interruptible	24.29%	17.14%
Special Contracts	4.83%	4.19%
Off System Transportation	10.57%	10.57%
TOTAL	6.22%	6.22%

The results using the more reliable zero intercept main allocation figures show that three of the six rate classes have returns that fall below the system average rate of return. In the next step, I applied the $4,277,456 rate increase proposed by Delta to the individual classes. I allocated this increase between classes as follows: The two classes with very high returns (Interruptible and Off System Sales) were assigned none of the increase, the one class with a slightly higher return was assigned the same increase proposed by Delta, and the remaining amount of the increase was assigned to the three classes with low returns in amounts so that each of these three classes (Residential, Large Non-Commercial, and Special Contracts) would produce an equal return of 7.81%. In the table below, I have compared the portion of the increase proposed by Delta that was assigned each class by the Delta study and by my revised study:

CLASS	DELTA PROPOSED PORTION OF INCREASE	AG PROPOSED PORTION OF INCREASE
Residential	71.61%	62.15%
Small Non-Residential	11.63%	11.63%
Large Non-Residential	16.76%	21.55%
Interruptible	0.00%	0.00%
Special Contracts	0.00%	4.66%
Off System Transportation	0.00%	0.00%
TOTAL	100.00%	100.00%

Based on the results of my corrected Cost of Service Study, I am recommending that percentages in the table above under the "AG Proposed" column be applied to what ever level of increase the Commission eventually allows Delta to come up with the amount of increase that each class will be assigned.

Q13: ONE OF THE DIFFERENCES BETWEEN THE PORTION OF THE INCREASE THAT WAS PROPOSED BY DELTA AND WHAT YOU HAVE PROPOSED IS THAT DELTA HAS NOT ASSIGNED ANY OF THE INCREASE TO SPECIAL CONTRACTS CUSTOMERS, WHILE YOU HAVE ASSIGNED THEM A SMALL PORTION OF THE INCREASE. WHY HAVE YOU TAKEN A DIFFERENT APPROACH?

A13: While the Special Contracts class has the lowest class rate of return (the second lowest in the Delta study), Delta chose to not assign any portion of the rate increase to this class. Delta expressed a fear that if these customers received a portion of the increase, they might leave the system. Delta did not express the same fear about Residential customers, to whom Delta has proposed to assign most of the proposed increase, 71.61%. This seems odd considering that Seelye Exhibit 8 shows that during the test-year Delta lost one percent of its Residential customers and no Special Contracts customers. If Residential customers are forced to take most of the proposed increase, as Delta has proposed, this will only encourage more residential customers to seek alternative heating sources and leave the Delta system. Like large Special Contracts customers, Residential customers also have alternatives, as Mr. Jennings explained on page 5 of his testimony, on lines 3 through 6. Recognizing that Residential customers as well as Special Contracts customers have alternatives and can leave the Delta system, and that in fact it has been the Residential customers that have left the system, I believe that both Residential and Special Contract customers should be assigned a portion of the increase.

Q14: IN THIS CASE THE ATTORNEY GENERAL HAS PROPOSED THAT DELTA RECEIVE AN INCREASE IN RATES THAT IS LOWER THAN THAT PROPOSED BY THE COMPANY. BASED ON THE RATE INCREASE PROPOSED BY THE ATTORNEY GENERAL, WHAT INCREASE HAVE YOU PROPOSED FOR EACH CLASS?

A14: Combining the recommendations of the witnesses for the Attorney General, Mr. Henkes has calculated that Delta is entitled to an increase of $1,364,420. I have substituted this proposed increase for the Delta proposed increase contained in my corrected Cost of Service Study, Exhibit DHBK-5. The results are presented in Exhibit DHBK-6. My Exhibit DHBK-6 contains only pages 33 and 34, since all of the other pages are identical to those same pages in Exhibit DHBK-5. The results from Exhibit DHBK-6, which are my recommendation for the Commission, are summarized in the table below:

CLASS	AG PROPOSED INCREASE
Residential	$848,005
Small Non-Residential	$158,679
Large Non-Residential	$294,099
Interruptible	$0
Special Contracts	$63,636
Off System Transportation	$0
TOTAL	$1,364,420

MONTHLY CUSTOMER CHARGE

Q15: IN HIS COST OF SERVICE STUDY, MR. SEELYE HAS CALCULATED THE AMOUNT OF CUSTOMER RELATED COSTS FOR EACH CLASS, AND FROM THAT CALCULATED A MONTHLY CUSTOMER CHARGE. DO YOU AGREE WITH HIS METHODOLOGY?

A15: I have some concerns about Mr. Seelye's methodology, which is contained in Exhibit 12. First, Mr. Seelye uses the overall Company rate of return for each class, instead of the return that he proposes for each class. The customer charge should be based on the proposed rates and rates of return for each individual class, and not the overall rate of return that is not actually applied to any class.

My other major concern is the costs that Mr. Seelye includes in his calculation. Mr. Seelye and I differ fundamentally concerning what costs should be collected through the fixed monthly customer charge. Mr. Seelye proposes to collect all costs he has labeled as customer related through the customer charge. The problem with this argument is that there are some costs that are given this "customer" label that actually should be collected on a commodity basis for each customer class. A good example is Account 904, Uncollectibles. The NARUC Gas Distribution Rate Design Manual identifies this account as one that is much more likely to vary with the amount of gas sold as opposed to varying with the number of customers. It should be collected from customers as part of a commodity charge, even though it is labeled as a customer account.

Q16: WHAT COSTS ARE PROPERLY COLLECTED WITH A MONTHLY CUSTOMER CHARGE?

A16: In the NARUC Gas Distribution Rate Design Manual, on page 12, the manual states:

> "The basis for the customer charge is that there are certain fixed costs that each customer should bear whether any gas is used at all. Examples of such costs are those associated with a service line, a regulator and a meter, recurring meter reading expenses, and administrative costs of servicing the account."

Beside Uncollectibles, another cost that is given the "customer" label but clearly does not fit the NARUC description of an appropriate cost to be collected through this monthly charge is distribution mains. Delta has included mains in its calculation of the charge level and it should not be included. In Exhibit DHBK-7, I have done the same calculation as Mr. Seelye has done in his Seelye Exhibit 12, except I have removed the costs associated with Account 904 and distribution mains.

Q17: BASED ON YOUR CALCULATIONS, WHAT CUSTOMER CHARGE ARE YOU RECOMMENDING?

A17: My calculations show that with Mr. Seelye's approach, modified to eliminate inappropriate costs that he has included, a residential gas customer charge of $8.97 per month can be justified based on the Cost of Service Study. I am proposing the Commission adopt a residential monthly customer charge of $9.00

per month. This charge level would amount to an increase of 12.5%, which is significantly higher than the overall increase requested by Delta in this case.

With respect to the Small Non-Residential class, the current charge of $17.00 per month is greater than the $14.61 per month calculated in Exhibit DHBK-7. As a result, I am recommending that the Commission lower the Small Non-Residential monthly customer charge to $14.60 per month.

Delta has proposed to raise the Large Non-Residential monthly customer charge from the current $50.00 per month to $80.00 per month. Exhibit DHBK-7 shows that only $70.96 can be justified for this class. Thus I am recommending a monthly customer charge for the Large Non-Residential class of $70.00 per month. Delta did not propose a change in the monthly customer charge for any other class.

RECONNECT CHARGE

Q18: DELTA HAS PROPOSED TO INCREASE THE RECONNECT CHARGE FROM $40.00 TO $48.00. DO YOU AGREE WITH THIS PROPOSED INCREASE?

A18: No. The Commission needs to keep in mind that the higher the reconnection fees, the greater the deterrent to quick reconnection. Delta's response to the Attorney General's First Data Request, Item 146, shows that far more customers are disconnected for non-payment than can afford to return to the system. Living in a household without gas for heat, hot water and cooking can be very hard on a family. The current Delta $40.00 reconnection fee is twice as high as the reconnection fee approved by the Commission in the recent LG&E rate case, Case No. 2003-00434. I am proposing that the Commission leave this fee unchanged, since the fee places such a burden on poor families. Because the Delta reconnection fee is already very high and places a significant burden on customers seeking to reconnect, it is important that this fee not be increased.

GTIR&D TARIFF RIDER

Q19: IN THIS CASE DELTA HAS PROPOSED A NEW GTIR&D TARIFF RIDER. DO YOU AGREE WITH THIS RIDER PROPOSED BY DELTA?

A19: No. Delta has proposed a new tariff rider to collect funds for the Gas Technology Institute for Research and Development (GTIR&D). In the past, funds were collected through a charge on the interstate pipelines. Since this charge has been phased out by FERC, Delta has proposed to reinstate the charge through a new tariff rider to be paid by sales customers only.

This proposal raises two questions; should such a fee be collected, and if so, should it be done through a separate rider? To answer the second question first, adding another surcharge to the bill through a separate rider is simply bad policy. Utilities that are involved in research and development project, such as electric utilities funding EPRI projects, generally pass these costs on to customers through base rates. I am unaware of money for research, funded by other utilities, that is collected from customers through a separate tariff rider on a bill. As a separate rider, Delta can apply this fee to sales customers only. If instead these moneys were collected in base rates, all customers, including transportation customers, would be making at least some contribution to GTIR&D research.

Delta has failed to provide a justification that demonstrates that this charge needs to be broken out as a separate tariff rider. In the past, this cost was simply included in the gas commodity charge, and not a separate fee. If the Commission allows Delta to charge this fee, it should be included in base rates and not as a separate charge on a customer's bill.

The question as to whether customers should be charged this fee in the first place is a more important question. This charge would only apply to sales customers, and thus transportation customers would not have to pay this fee. Delta provided a cost benefit analysis of this research in response to the PSC's Second Data Request, Item 7. On pages 5 through 9 of this analysis, a list of 153 benefits are quantified. This provides benefits for residential, commercial, industrial, power generation, transportation, distribution, pipeline, and exploration and production sectors. What I find troubling is that out of 153 benefits, only 1 is for the residential sector. This is in stark contrast to the fact that residential customers will be asked to pay close to half of the total money collected. The transportation customers, who will no longer pay this fee, receive 8 benefits though they pay nothing. In the same way, power generation and mobile transportation customer will pay nothing and receive many more benefits than residential customers. While residential customers may receive some indirect benefits from research to benefit exploration and production, pipelines, and distribution, the parties directly involved in these endeavors are likely to be the primary beneficiaries.

The GTIR&D fund appears to be a situation where the primary beneficiaries are no longer contributing to this research, and the retail customers, primarily residential customer, are being asked to pay the entire bill when their share of the benefits is small. The proposal put forth by Delta for the captive sales customers to pay the entire bill for research that primarily benefits others is not equitable. Thus I am recommending that the Commission reject all together the funding of GTIR&D by retail ratepayers.

Q20: DOES THIS CONCLUDE YOUR TESTIMONY?

A20: Yes it does.

I, David H. Brown Kinloch, certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

Dated this 29th day of June, 2004.

David H. Brown Kinloch

Affirmed to and subscribed
before me, this 29th day
of June, 2004.

Notary Public

My Commission Expires: April 26, 2006

Exhibit DHBK-1

Delta Zero Intercept Graph

Case No. 2004-00067

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains
As of 12-31-98

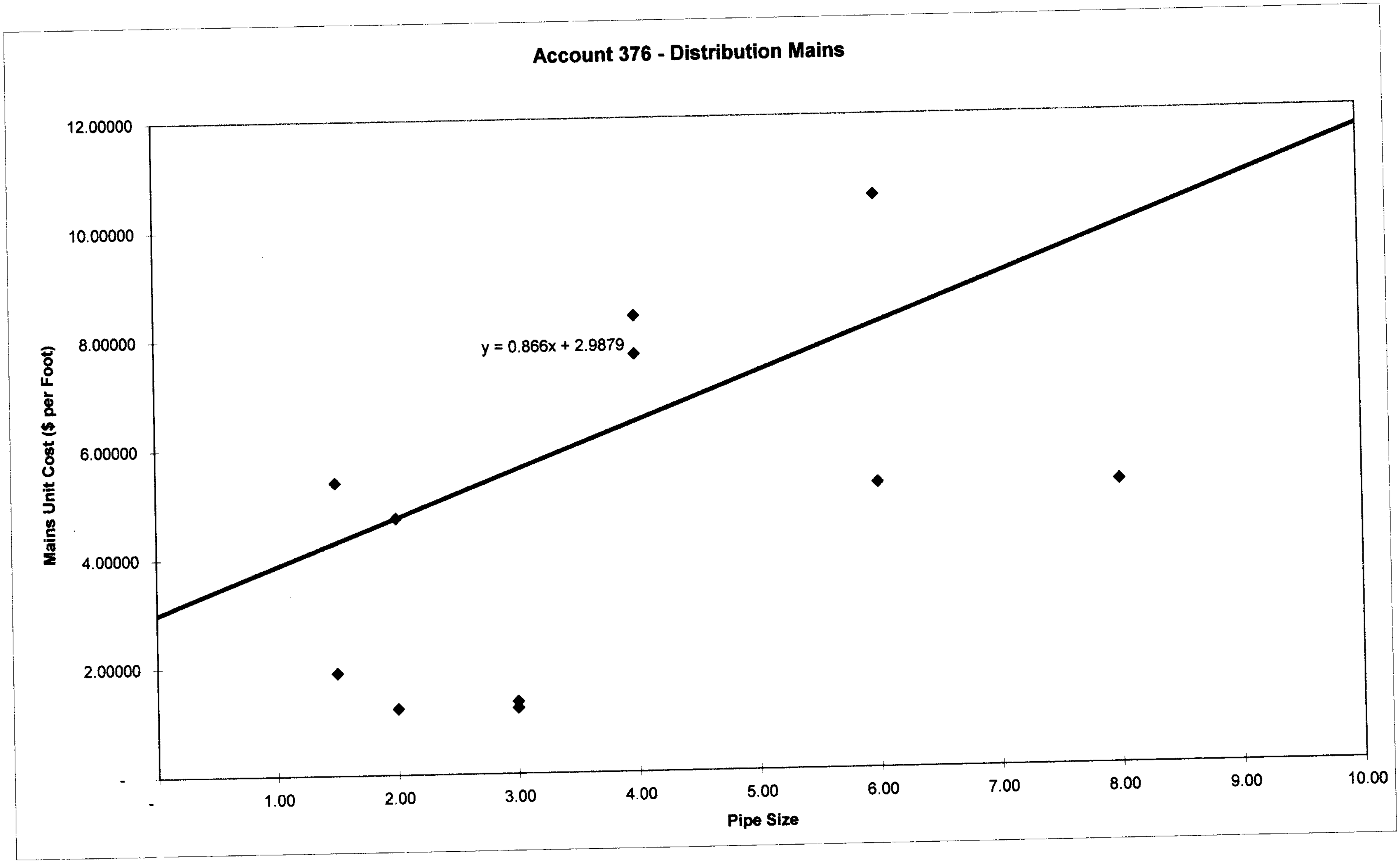

Exhibit DHBK-2

LG&E Zero Intercept Graph

Case No. 2000-080

AG 157
Page 2 of 21

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 1999

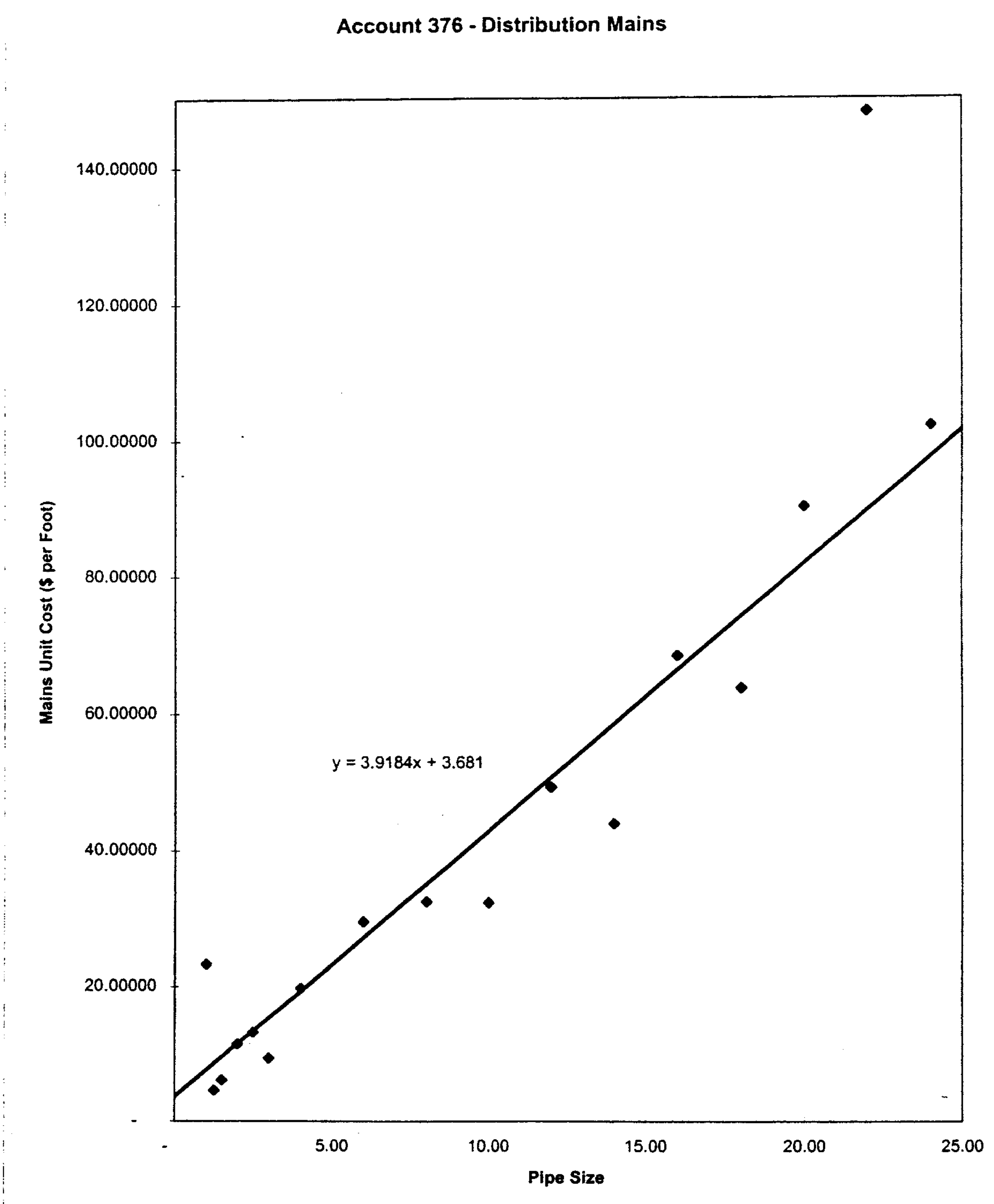

Exhibit DHBK-3

AG's Zero Intercept Analysis

Primary Main Analysis

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Zero Intercept Analysis
Primary Mains Analysis
Account 376 -- Distribution Mains

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per Foot)	1.8277948	0.00
Zero Intercept ($ per Foot)	1.0619142	0.00
R-Square	1.0000000	

Plant Classification

Total Number of Units		7,430,681
Zero Intercept		1.0619142
Zero Intercept Cost	$	7,890,746
Total Cost of Sample	$	39,264,434
Percentage of Total		0.200964208
Percentage Classified as Customer-Related		20.10%
Percentage Classified as Demand-Related		79.90%

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Zero Intercept Analysis
Primary Mains Analysis
Account 376 -- Distribution Mains

Description	Pipe Size	Pipe Size	Net Cost of Plant	Percent Total Cost	Quantity (Feet)	Unit Cost ($ per Foot)	y	x
Distribution Main Pipe, Under 2" Plastic	1.5	1.500	$ 2,680,237.57	6.83%	497,888	5.38321	5.38321	1.50
Distribution Main Pipe, 2" Plastic	2.0	2.000	20,104,430.25	51.20%	4,261,667	4.71750	4.71750	2.00
Distribution Main Pipe, 3" Plastic	3.0	3.000	118,869.31	0.30%	89,393	1.32974	1.32974	3.00
Distribution Main Pipe, 4" Plastic	4.0	4.000	10,794,416.15	27.49%	1,289,179	8.37309	8.37309	4.00
Distribution Main Pipe, 6" Plastic	6.0	6.000	619,866.07	1.58%	58,933	10.51815	10.51815	6.00
Distribution Main Pipe, Under 2" Steel	1.5	1.500	179,796.34	0.46%	95,274	1.88715	1.88715	1.50
Distribution Main Pipe, 2" Steel	2.0	2.000	504,942.71	1.29%	414,290	1.21881	1.21881	2.00
Distribution Main Pipe, 3" Steel	3.0	3.000	83,446.38	0.21%	68,844	1.21211	1.21211	3.00
Distribution Main Pipe, 4" Steel	4.0	4.000	2,358,537.03	6.01%	307,346	7.67388	7.67388	4.00
Distribution Main Pipe, 6" Steel	6.0	6.000	1,402,551.18	3.57%	267,813	5.23705	5.23705	6.00
Distribution Main Pipe, 8" Steel	8.0	8.000	417,340.51	1.06%	80,054	5.21324	5.21324	8.00
Total			$ 39,264,433.50	100.00%	7,430,681			

Primary Main Description	Pipe Size	Pipe Size	Net Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)	y	x
Distribution Main Pipe, 2" Plastic	2.0	2.000	20,104,430.25	4,261,667	4.71750	4.71750	2.00
Distribution Main Pipe, 4" Plastic	4.0	4.000	10,794,416.15	1,289,179	8.37309	8.37309	4.00
Primary Mains Total			30,898,846.40	5,550,846			
Percent of All Mains			**78.69%**	**74.70%**			

OFFICE OF THE ATT :Y GENERAL
Delta Natural Gas - Ca.. .o. 2004-00067

Zero Intercept Analysis
Primary Mains Analysis

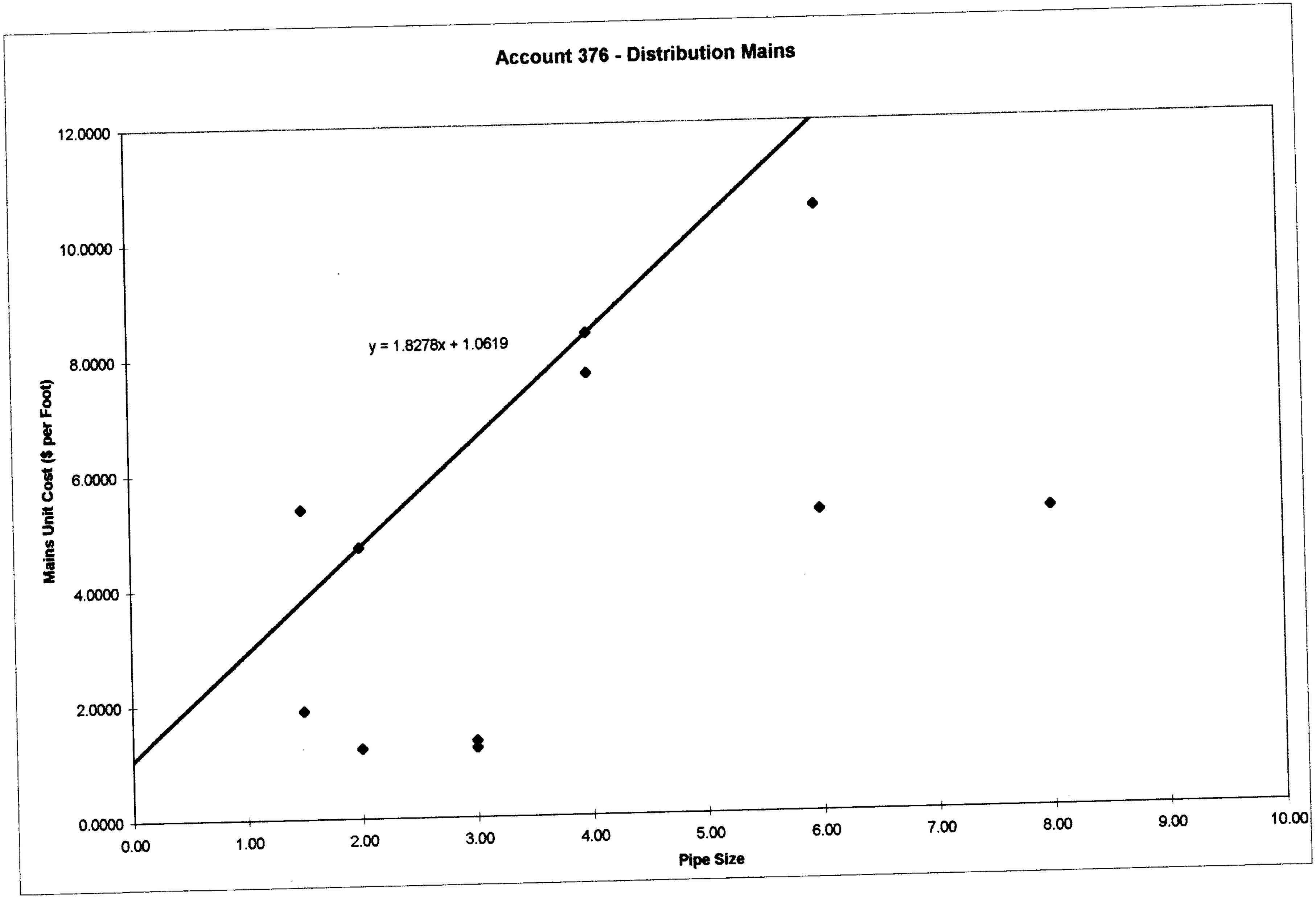

Exhibit DHBK - 3
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Exhibit DHBK-4

AG's Cost of Service Study

Functional Assignment & Classification of Costs

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Gas Plant at Original Cost													
Underground Storage Plant													
350-357	Underground Storage Plant	PT350	F003	$	12,063,181	12,063,181	-	-	-	-	-	-	-
Total Storage Plant		PTST		$	12,063,181	$ 12,063,181	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant													
325-371	Transmission	PT365	F005	$	43,524,928	-	-	43,524,928	-	-	-	-	-
Distribution Plant													
374 & 304	Land and Land Rights	PT374	F008	$	316,024	-	-	-	-	-	316,024	-	-
375	Structures & Improvements	PT375	F008		116,064	-	-	-	-	-	116,064	-	-
376	Mains	PT376	F009		56,694,785	-	-	-	-	-	-	45,299,134	11,395,652
378	Meas. & Reg. Sta. Equip. - General	PT378	F008		1,252,562	-	-	-	-	-	1,252,562	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008		398,371	-	-	-	-	-	398,371	-	-
380	Services	PT380	F010		10,856,853	-	-	-	-	-	-	-	-
381	Meters	PT381	F011		8,426,711	-	-	-	-	-	-	-	-
382	Meter Installations	PT382	F011		2,865,091	-	-	-	-	-	-	-	-
383	House Regulators	PT383	F011		2,679,313	-	-	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011		-	-	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011		1,400,779	-	-	-	-	-	-	-	-
387	Other Equipment	PT387	F011		-	-	-	-	-	-	-	-	-
	Mt. Olivet	MTOVT			464,945	-	-	-	-	-	11,393	247,764	62,329
Sub-Total Distribution Plant		PTDSUB		$	85,471,500	-	-	-	-	-	2,094,415	45,546,898	11,457,981
Transmission & Distribution Subtotal		TDSUB		$	128,996,428	$ -	$ -	$ 43,524,928	$ -	$ -	$ 2,094,415	$ 45,546,898	$ 11,457,981
U-T-D Subtotal		PTSUB		$	141,059,609	12,063,181	-	43,524,928	-	-	2,094,415	45,546,898	11,457,981
117	Gas Stored Underground/Non-Current	PT117	F003	$	4,208,069	4,208,069	-	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB		53,151	4,545	-	16,400	-	-	789	17,162	4,317
389-399	General Plant	PT389	PTSUB		18,941,023	1,619,804	-	5,844,385	-	-	281,231	6,115,888	1,538,540
	Common Utility Plant	PTCP	PTSUB		-	-	-	-	-	-	-	-	-
Total Plant in Service		PTIS		$	164,261,851	17,895,600	-	49,385,713	-	-	2,376,435	51,679,948	13,000,838

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost							
Underground Storage Plant							
350-357	Underground Storage Plant	PT350	F003	-	-	-	-
Total Storage Plant		PTST		$ -	$ -	$ -	$ -
Transmission Plant							
325-371	Transmission	PT365	F005	-	-	-	-
Distribution Plant							
374 & 304	Land and Land Rights	PT374	F008	-	-	-	-
375	Structures & Improvements	PT375	F008	-	-	-	-
376	Mains	PT376	F009	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	-	-	-
380	Services	PT380	F010	10,856,853	-	-	-
381	Meters	PT381	F011	-	8,426,711	-	-
382	Meter Installations	PT382	F011	-	2,865,091	-	-
383	House Regulators	PT383	F011	-	2,679,313	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	1,400,779	-	-
387	Other Equipment	PT387	F011	-	-	-	-
	Mt. Olivet	MTOVT		59,382	84,077	-	-
Sub-Total Distribution Plant		PTDSUB		10,916,235	15,455,971	-	-
Transmission & Distribution Subtotal		TDSUB		$ 10,916,235	$ 15,455,971	$ -	$ -
U-T-D Subtotal		PTSUB		10,916,235	15,455,971	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	4,113	5,824	-	-
389-399	General Plant	PT389	PTSUB	1,465,796	2,075,377	-	-
	Common Utility Plant	PTCP	PTSUB	-	-	-	-
Total Plant in Service		PTIS		12,386,144	17,537,172	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Gas Plant at Original Cost (Continued)												
Construction Work In Progress												
Underground Storage	CWIPUS	F003	$	13,667	13,667	-	-	-	-	-	-	-
Transmission	CWIPTR	F005	$	1,374,496	-	-	1,374,496	-	-	-	-	-
Distribution Mains	CWIPDM	F009	$	134,858	-	-	-	-	-	-	107,752	27,106
Other Distribution	CWIPOD	PTDSUB	$	17,386	-	-	-	-	-	426	9,265	2,331
General	CWIPCO	PT389	$	192,159	16,433	-	59,292	-	-	2,853	62,046	15,609
Total CWIP	CWIP		$	1,732,567	30,100	-	1,433,788	-	-	3,279	179,063	45,046
Total Gas Plant at Original Cost	PTT		$	165,994,418	17,925,700	-	50,819,501	-	-	2,379,715	51,859,011	13,045,884

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost (Continued)						
Construction Work In Progress						
Underground Storage	CWIPUS	F003	-	-	-	-
Transmission	CWIPTR	F005	-	-	-	-
Distribution Mains	CWIPDM	F009	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	2,221	3,144	-	-
General	CWIPCO	PT389	14,871	21,055	-	-
Total CWIP	CWIP		17,091	24,199	-	-
Total Gas Plant at Original Cost	PTT		12,403,236	17,561,371	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Net Cost Rate Base											
Total Gas Utility Plant at Original Cost			$ 165,994,418	$ 17,925,700	$ -	$ 50,819,501	$ -	$ -	$ 2,379,715	$ 51,859,011	$ 13,045,884
Less:											
Reserve for Depreciation											
Underground Storage	DEPRUS	PTST	$ 3,508,673	3,508,673	-	-	-	-	-	-	-
Transmission	DEPTR	F005	14,968,000	-	-	14,968,000	-	-	-	-	-
Distribution	DEPRDI	PTDSUB	24,832,254	-	-	-	-	-	608,496	13,232,857	3,328,916
General	DEPRGE	PT389	9,655,098	825,688	-	2,979,148	-	-	143,356	3,117,545	784,264
Common	DEPRCO	PTCP	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve	DEPR		$ 52,964,025	$ 4,334,361	$ -	$ 17,947,148	$ -	$ -	$ 751,852	$ 16,350,403	$ 4,113,180
Customer Advances For Construction	CAD	CADAL	$ 105,692	-	-	-	-	-	-	70,875	17,830
Accum. Deferred Income Taxes	DIT	PTSUB	14,697,866	1,256,937	-	4,535,129	-	-	218,230	4,745,811	1,193,877
Investment Tax Credit	ITC	PTSUB	-	-	-	-	-	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-	-	-	-	-	-
PLUS:											
Materials and Supplies	MSP	PTSUB	$ 478,139	40,890	-	147,533	-	-	7,099	154,387	38,838
Prepayments	PPY	PTSUB	351,876	30,092	-	108,574	-	-	5,225	113,618	28,582
Gas Stored Underground	GSU	F003	6,363,748	6,363,748	-	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	1,290,427	40,875	24,670	299,830	28,284	6,316	16,742	364,638	91,730
Adjustments:											
Unamortized Debt		PTSUB	$ 4,185,070	357,900	-	1,291,333	-	-	62,139	1,351,322	339,945
Regulatory		PTSUB	0	-	-	-	-	-	-	-	-
Unrecovered SFAS 143 Adoption Costs		PTSUB	30,133	2,577	-	9,298	-	-	447	9,730	2,448
Depreciation Adjustment		PTSUB	145,431	12,437	-	44,874	-	-	2,159	46,958	11,813
Net Cost Rate Base	NCRB		$ 111,071,658	$ 19,182,921	$ 24,670	$ 30,238,664	$ 28,284	$ 6,316	$ 1,503,444	$ 32,732,575	$ 8,234,352

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Net Cost Rate Base						
Total Gas Utility Plant at Original Cost			$ 12,403,236	$ 17,561,371	$ -	$ -
Less:						
Reserve for Depreciation						
Underground Storage	DEPRUS	PTST	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-
Distribution	DEPRDI	PTDSUB	3,171,522	4,490,463	-	-
General	DEPRGE	PT389	747,183	1,057,914	-	-
Common	DEPRCO	PTCP	-	-	-	-
Total Depreciation Reserve	DEPR		$ 3,918,705	$ 5,548,377	$ -	$ -
Customer Advances For Construction	CAD	CADAL	16,987	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	1,137,429	1,610,452	-	-
Investment Tax Credit	ITC	PTSUB	-	-	-	-
Deferred Income Taxes-FAS 109	FAS109	PTSUB	-	-	-	-
PLUS:						
Materials and Supplies	MSP	PTSUB	37,002	52,390	-	-
Prepayments	PPY	PTSUB	27,231	38,555	-	-
Gas Stored Underground	GSU	F003	-	-	-	-
Cash Working Capital	CWC	OMT	82,216	127,567	207,228	332
Adjustments:						
Unamortized Debt		PTSUB	323,872	458,560	-	-
Regulatory		PTSUB	-	-	-	-
Unrecovered SFAS 143 Adoption Costs		PTSUB	2,332	3,302	-	-
Depreciation Adjustment		PTSUB	11,255	15,935	-	-
Net Cost Rate Base	NCRB		$ 7,814,021	$ 11,098,851	$ 207,228	$ 332

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Labor Expenses												
Production Expenses												
Operation & Maintenance												
753	Wells and Gathering	LB 753	F006	16,481	-	-	-	16,481	-	-	-	-
754	Compressor Station	LB754	F006	40,443	-	-	-	40,443	-	-	-	-
764	Maintenance of Wells and Gathering	LB764	F006	1,115	-	-	-	1,115	-	-	-	-
765	Maintenance of Compressor Station	LB765	F006	4,317	-	-	-	4,317	-	-	-	-
Total Production Operation & Maintenance Expenses				62,356	-	-	-	62,356	-	-	-	-
807-813	Procurement Expenses	LB807	DMCM	$ -	-	-	-	-	-	-	-	-
Storage Expenses												
Operation												
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	46,512	46,512	-	-	-	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	16,996	-	16,996	-	-	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ 63,508	$ 46,512	$ 16,996	$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense												
Maintenance												
830	Maintenance Super and Eng.	LB830	MSE	$ -	-	-	-	-	-	-	-	-
831	Maintenance of Strucures	LB831	F003	-	-	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	329	329	-	-	-	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	5,430	-	5,430	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	599	599	-	-	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ 6,358	$ 929	$ 5,430	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		$ 69,866	47,441	22,425	-	-	-	-	-	-

OFFICE OF THE ATTO...Y GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses							
Production Expenses							
Operation & Maintenance							
753	Wells and Gathering	LB 753	F006	-	-	-	-
754	Compressor Station	LB754	F006	-	-	-	-
764	Maintenance of Wells and Gathering	LB764	F006	-	-	-	-
765	Maintenance of Compressor Station	LB765	F006	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-
807-813	Procurement Expenses	LB807	DMCM	-	-	-	-
Storage Expenses							
Operation							
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-
816	Well Expenses	LB816	F003	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-
826	Rents	LB826	F003	-	-	-	-
Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -
Storage Expense							
Maintenance							
830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-
Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -
Total Storage Labor		LBS		-	-	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Labor Expenses (Continued)												
Transmission												
850-867	Transmission Expenses	LB850	F005	$ -	-	-	-	-	-	-	-	-
Distribution Expenses												
Operation												
870	Operation Supr and Engr	LB870	DOES	$ -	-	-	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007	-	-	-	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	-	-	-	-	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-	-	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-	-	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-	-	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010		-	-	-	-	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009		-	-	-	-	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	-	-	-	-	-	-	-	-	-
881	Rents	LB881	PTDSUB									
Total Operations Distribution Labor		LBDO		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ 56,924	$ -	$ -	$ -	$ 56,924	$ -	$ -	$ -	$ -

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)							
Transmission							
850-867	Transmission Expenses	LB850	F005	-	-	-	-
Distribution Expenses							
Operation							
870	Operation Supr and Engr	LB870	DOES	-	-	-	-
871	Dist Load Dispatching	LB871	F007	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	-	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	-	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-
880	Other Expenses	LB880	PTDSUB	-	-	-	-
881	Rents	LB881	PTDSUB	-	-	-	-
Total Operations Distribution Labor		LBDO		$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ -	$ -	$ -	$ -

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains 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	57,925	-	-	-	-	-	-	46,282	11,643
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	15,677	-	-	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	12,769	-	-	-	-	-	313	6,804	1,712
898	Maintenance Transportaion Equip	LB898	PTDSUB	37,180	-	-	-	-	-	911	19,813	4,984
900	Trans & Distribution Expenses	LB900	TDSUB	2,377,376	-	-	802,155	-	-	38,600	839,419	211,168
Total Maintenance Labor		LBDM		$ 2,500,927	$ -	$ -	$ 802,155	$ -	$ -	$ 39,824	$ 912,319	$ 229,507
Total Transmission & Distribution Labor		LBTD		$ 2,563,283	$ -	$ -	$ 802,155	$ 62,356	$ -	$ 39,824	$ 912,319	$ 229,507
Customer Accounts Expense												
901	Supervision	LB901	F012	$ -	-	-	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	$ 362,869	-	-	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ 362,869	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	LB907	F013	$ -	-	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	LB911	F013	$ -	-	-	-	-	-	-	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	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	-	-	-	-
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	-	15,677	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	1,631	2,309	-	-
898	Maintenance Transportaion Equip	LB898	PTDSUB	4,749	6,723	-	-
900	Trans & Distribution Expenses	LB900	TDSUB	201,184	284,850	-	-
Total Maintenance Labor		LBDM		$ 207,563	$ 309,560	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 207,563	$ 309,560	$ -	$ -
Customer Accounts Expense							
901	Supervision	LB901	F012	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-
903	Customer Records and Collections	LB903	F012	-	-	362,869	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ 362,869	$ -
Customer Service Expenses							
907-910	Customer Service	LB907	F013	-	-	-	-
Sales Expenses							
911-916	Sales Expenses	LB911	F013	-	-	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Labor Expenses (Continued)												
Administrative & General												
920	Admin and General Salaries	LB920	LBSUB	$ 2,183,224	34,571	16,341	584,537	45,439	-	29,020	664,814	167,244
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	797,893	12,634	5,972	213,628	16,606	-	10,606	242,967	61,122
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		$ 2,981,117	$ 47,205	$ 22,314	$ 798,165	$ 62,045	$ -	$ 39,626	$ 907,781	$ 228,365
Total Labor Expense		LBTOT		$ 5,977,135	$ 94,646	$ 44,739	$ 1,600,320	$ 124,401	$ -	$ 79,449	$ 1,820,100	$ 457,872

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector		Services Customer		Meters Customer		Customer Accounts Customer		Customer Service Expense Customer
Labor Expenses (Continued)											
Administrative & General											
920	Admin and General Salaries	LB920	LBSUB		151,253		225,579		264,426		-
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		55,278		82,441		96,639		-
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		$	206,531	$	308,020	$	361,065	$	-
Total Labor Expense		LBTOT		$	414,094	$	617,580	$	723,934	$	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Operation & Maintenance Expenses											
Production Expenses											
Operation & Maintenance											
753 Wells and Gathering	OM 753	F006	26,953	-	-	-	26,953	-	-	-	-
754 Compressor Station	OM754	F006	85,900	-	-	-	85,900	-	-	-	-
764 Maintenance of Wells and Gathering	OM764	F006	2,315	-	-	-	2,315	-	-	-	-
765 Maintenance of Compressor Station	OM765	F006	19,850	-	-	-	19,850	-	-	-	-
Total Production Operation & Maintenance Expenses			135,019	-	-	-	135,019	-	-	-	-
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	48,330	48,330	-	-	-	-	-	-	-
817 Lines Expenses	OM817	F003	-	-	-	-	-	-	-	-	-
818 Compressor Station Exp - Payroll	OM818	F004	32,027	-	32,027	-	-	-	-	-	-
819 Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-	-	-	-
820 Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-	-	-
821 Purification of Natural Gas	OM821	F004	86,120	-	86,120	-	-	-	-	-	-
823 Gas losses	OM823	F004	-	-	-	-	-	-	-	-	-
824 Other Expenses	OM824	F004	7,410	-	7,410	-	-	-	-	-	-
825 Storage Well Royalities	OM825	F003	55,918	55,918	-	-	-	-	-	-	-
826 Rents	OM826	F003	-	-	-	-	-	-	-	-	-
Total Operation Expenses	OMOE		$ 229,804	$ 104,247	$ 125,557	$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense											
Maintenance											
830 Maintenance Super and Eng.	OM830	MSE	$ -	-	-	-	-	-	-	-	-
831 Maintenance of Structures	OM831	F003	6,166	6,166	-	-	-	-	-	-	-
832 Maintenance of Resevoirs	OM832	F003	43,079	43,079	-	-	-	-	-	-	-
833 Maintenance of Lines	OM833	F003	-	-	-	-	-	-	-	-	-
834 Main of Compressor Station Equipment	OM834	F004	19,173	-	19,173	-	-	-	-	-	-
835 Main of Meas and Reg Sta. Equip	OM835	F003	1,561	1,561	-	-	-	-	-	-	-
836 Main of Purification Equip	OM836	F004	-	-	-	-	-	-	-	-	-
837 Main of Other Equipment	OM837	F003	4,510	4,510	-	-	-	-	-	-	-
Total Maintenance Expense	OMME		$ 74,491	$ 55,317	$ 19,173	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense	OMS		$ 304,295	159,564	144,731	-	-	-	-	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	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		-	-	-	-

OFFICE OF THE ATT…EY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Operation & Maintenance Expenses (Continued)												
Transmission												
850-867	Transmission Expenses	OM850	F005	$ 78,586	-	-	78,586	-	-	-	-	-
Distribution Expenses												
Operation												
870	Operation Supr and Engr	OM870	DOES	$ -	-	-	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	41,893	-	-	-	-	41,893	-	-	-
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	338,572	-	-	-	-	-	8,296	180,422	45,388
881	Rents	OM881	PTDSUB	17,103	-	-	-	-	-	419	9,114	2,293
Total Operations Distribution Expense		OMDO		$ 397,568	-	-	-	-	41,893	8,716	189,536	47,680
Total Transmission and Distribution Oper Exp		OMTDO		$ 589,008	$ -	$ -	$ 78,586	$ 112,853	$ 41,893	$ 8,716	$ 189,536	$ 47,680

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	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	43,242	61,225	-	-
881	Rents	OM881	PTDSUB	2,184	3,093	-	-
Total Operations Distribution Expense		OMDO		45,426	64,317	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 45,426	$ 64,317	$ -	$ -

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

	Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains 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	130,018	-	-	-	-	-	-	103,885	26,134
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	6,421	-	-	-	-	-	6,421	-	-
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	60,807	-	-	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	92,880	-	-	-	-	-	2,276	49,495	12,451
898	Maintenance Transportaion Equip	OM898	PTDSUB	37,180	-	-	-	-	-	911	19,813	4,984
900	Trans & Distribution Expenses	OM900	TDSUB	3,030,488	-	-	1,022,523	-	-	49,204	1,070,024	269,180
	Total Maintenance Expenses	OMME		$ 3,357,795	$ -	$ -	$ 1,022,523	$ -	$ -	$ 58,812	$ 1,243,217	$ 312,749
	Total Transmission & Distribution Expenses	OMDE		$ 3,968,968	$ -	$ -	$ 1,101,109	$ 135,019	$ 41,893	$ 67,527	$ 1,432,752	$ 360,430
Customer Accounts Expense												
901	Supervision	OM901	F012	$ -	-	-	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	$ 589,962	-	-	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012	478,567	-	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-	-	-	-
	Total Customer Accounts Expense	OMCA		$ 1,068,529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses												
907-910	Customer Service	OM907	F013	$ -	-	-	-	-	-	-	-	-
Sales Expenses												
911-916	Sales Expenses	OM911	F013	$ 2,204	-	-	-	-	-	-	-	-

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	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	-	-	-	-
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	-	60,807	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	11,862	16,796	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	4,749	6,723	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	256,453	363,104	-	-
Total Maintenance Expenses		OMME		$ 273,064	$ 447,430	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 318,490	$ 511,748	$ -	$ -
Customer Accounts Expense							
901	Supervision	OM901	F012	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-
903	Customer Records and Collections	OM903	F012	-	-	589,962	-
904	Uncollectible Accounts	OM904	F012	-	-	478,567	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ 1,068,529	$ -
Customer Service Expenses							
907-910	Customer Service	OM907	F013	-	-	-	-
Sales Expenses							
911-916	Sales Expenses	OM911	F013	-	-	-	2,204

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Operation & Maintenance Expenses (Continued)												
Administrative & General												
920	Admin and General Salaries	OM920	LBSUB	$ 2,270,974	35,960	16,998	608,031	47,265	-	30,186	691,535	173,966
921	Office Supplies and Expense	OM921	LBSUB	478,619	7,579	3,582	128,146	9,961	-	6,362	145,745	36,664
922	Admin. Expenses Transferred	OM922	LBSUB	(2,352,284)	(37,248)	(17,607)	(629,801)	(48,958)	-	(31,267)	(716,295)	(180,194)
923	Outside Services Employed	OM923	OMSUB	702,629	20,980	19,029	144,774	17,752	5,508	8,878	188,378	47,389
924	Property Insurance	OM924	PTT	550,836	59,485	-	168,639	-	-	7,897	172,089	43,291
925	Injuries and Damages	OM925	PTT	-	-	-	-	-	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	2,716,909	43,021	20,336	727,426	56,547	-	36,114	827,327	208,126
927	Franxhise Requirement	OM927	PTT	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	143,222	15,467	-	43,848	-	-	2,053	44,745	11,256
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	539,236	16,101	14,604	111,107	13,624	4,227	6,814	144,572	36,369
931	Rents	OM931	PTT	-	-	-	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	154,712	13,231	-	47,737	-	-	2,297	49,955	12,567
Total Administrative and General Expense		OMAGT		$ 5,204,852	$ 174,575	$ 56,943	$ 1,349,907	$ 96,192	$ 9,735	$ 69,334	$ 1,548,051	$ 389,434
Total Operation & Maintenance Expense		OMT		$ 10,548,848	$ 334,139	$ 201,674	$ 2,451,016	$ 231,211	$ 51,629	$ 136,861	$ 2,980,803	$ 749,864

OFFICE OF THE ATTO...EY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)							
Administrative & General							
920	Admin and General Salaries	OM920	LBSUB	157,332	234,646	275,054	-
921	Office Supplies and Expense	OM921	LBSUB	33,159	49,453	57,969	-
922	Admin. Expenses Transferred	OM922	LBSUB	(162,966)	(243,047)	(284,902)	-
923	Outside Services Employed	OM923	OMSUB	41,875	67,285	140,490	290
924	Property Insurance	OM924	PTT	41,159	58,276	-	-
925	Injuries and Damages	OM925	PTT	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	188,227	280,721	329,064	-
927	Franxhise Requirement	OM927	PTT	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	10,702	15,152	-	-
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	32,137	51,638	107,820	222
931	Rents	OM931	PTT	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	11,973	16,952	-	-
Total Administrative and General Expense		OMAGT		$ 353,598	$ 531,075	$ 625,496	$ 512
Total Operation & Maintenance Expense		OMT		$ 672,088	$ 1,042,823	$ 1,694,025	$ 2,716

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Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Depreciation Expenses												
Underground Storage												
350-357	Underground Storage Plant	DP350	F003	$ 481,354	481,354	-	-	-	-	-	-	-
Transmission												
365-371	Transmission Plant	DP365	F005	$ 1,061,222	-	-	1,061,222	-	-	-	-	-
Distribution												
374	Land & Land Rights	DP374	F008	$ -	-	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	3,423	-	-	-	-	-	3,423	-	-
376	Mains	DP376	F009	1,390,369	-	-	-	-	-	-	1,110,905	279,464
378	Meas & Reg Station Eq.-Gen	DP378	F008	35,031	-	-	-	-	-	35,031	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	11,666	-	-	-	-	-	11,666	-	-
380	Services	DP380	F010	259,463	-	-	-	-	-	-	-	-
381	Meters	DP381	F011	222,606	-	-	-	-	-	-	-	-
382	Meter Installations	DP382	F011	84,115	-	-	-	-	-	-	-	-
383	House Regulators	DP383	F011	78,288	-	-	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	40,857	-	-	-	-	-	-	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-	-	-	-
	Other		PTSUB	174	15	-	54	-	-	3	56	14
Total Distribution				$ 2,125,992	$ 15	$ -	$ 54	$ -	$ -	$ 50,122	$ 1,110,961	$ 279,478
117	Gas Stored Underground	DP117	F003	$ -	-	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	552,594	47,257	-	170,507	-	-	8,205	178,428	44,886
Common Utility Plant		DPCP	PTSUB	-	-	-	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(12,000)	(1,026)	-	(3,703)	-	-	(178)	(3,875)	(975)
Accretion Expense		ACCRTN	PTSUB	(18,658)	(1,596)	-	(5,757)	-	-	(277)	(6,025)	(1,516)
Total Depreciation Expense		DEPREX		$ 4,190,504	$ 526,004	$ -	$ 1,222,322	$ -	$ -	$ 57,872	$ 1,279,490	$ 321,874

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Functional Assignment and Classification

Description		Name	Vector	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	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-
380	Services	DP380	F010	259,463	-	-	-
381	Meters	DP381	F011	-	222,606	-	-
382	Meter Installations	DP382	F011	-	84,115	-	-
383	House Regulators	DP383	F011	-	78,288	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	40,857	-	-
387	Other Equipment	DP387	F011	-	-	-	-
	Other		PTSUB	13	19	-	-
Total Distribution				$ 259,477	$ 425,885	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-
389-399	General Plant	DP389	PTSUB	42,764	60,548	-	-
Common Utility Plant		DPCP	PTSUB	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(929)	(1,315)	-	-
Accretion Expense		ACCRTN	PTSUB	(1,444)	(2,044)	-	-
Total Depreciation Expense		DEPREX		$ 299,868	$ 483,074	$ -	$ -

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Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Taxes Other Than Income Taxes											
Liscense & Privilege Fee	OTRE	PTT	$ 5,059	546	-	1,549	-	-	73	1,581	398
Property Taxes	OTPP	PTT	995,052	107,455	-	304,637	-	-	14,265	310,868	78,203
Payroll Taxes	OTUN	LBTOT	521,120	8,252	3,901	139,525	10,846	-	6,927	158,686	39,920
Total Taxes Other Than Income Taxes	OTT		$ 1,521,231	$ 116,254	$ 3,901	$ 445,711	$ 10,846	$ -	$ 21,265	$ 471,135	$ 118,521
Interest on Long Term Debt	INT	PTT	$ 4,562,696	492,725	-	1,396,878	-	-	65,411	1,425,451	358,593

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Cost of Service Study
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Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes						
Liscense & Privilege Fee	OTRE	PTT	378	535	-	-
Property Taxes	OTPP	PTT	74,351	105,271	-	-
Payroll Taxes	OTUN	LBTOT	36,103	53,844	63,117	-
Total Taxes Other Than Income Taxes	OTT		$ 110,832	$ 159,651	$ 63,117	$ -
Interest on Long Term Debt	INT	PTT	340,928	482,710	-	-

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Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Functional Assignment Vectors											
Gas Supply Demand	F001		1.000000	0.000000	0.000000	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	0.000000	0.000000
Storage Demand	F003		1.000000	1.000000	0.000000	0.000000	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	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.799000	0.201000
Services	F010		1.000000	0.000000	0.000000	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	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	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	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 100,219,713	$ -	$ -	$ 43,524,928	$ -	$ -	$ -	$ 45,299,134	$ 11,395,652

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Cost of Service Study
12 Months Ended December 31, 2003

Functional Assignment and Classification

Description	Name	Vector	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
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB		$ -	$ -	$ -	$ -

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Cost of Service Study
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Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains Demand	Distribution Mains Customer
Internally Generated Functional Vectors											
Sub-Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024504	0.532890	0.134056
Storage-Transmission-Distribution Subtotal		PTSUB	1.000000	0.085518	-	0.308557	-	-	0.014848	0.322891	0.081228
Total Storage Plant		PTST	1.000000	1.000000	-	-	-	-	-	-	-
Transmission Plant		PT365	1.000000	-	-	1.000000	-	-	-	-	-
General Plant		PT389	1.000000	0.085518	-	0.308557	-	-	0.014848	0.322891	0.081228
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024504	0.532890	0.134056
Sub-Total CWIP		CWIP	1.000000	0.017373	-	0.827552	-	-	0.001893	0.103351	0.026000
Total Depreciation Reserve		DEPR	1.000000	0.081836	-	0.338855	-	-	0.014196	0.308708	0.077660
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	0.085518	-	0.308557	-	-	0.014848	0.322891	0.081228
Transmission and Distribution Payroll		LBTD	1.000000	-	-	0.312940	0.024326	-	0.015536	0.355918	0.089536
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	0.434295	-	-	-	0.451998	0.113707
Storage Operation Expenses Subtotal	OSE		63,508	46,512	16,996	-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		6,358	929	5,430	-	-	-	-	-	-
Mains & Services	CADAL		67,551,639	-	-	-	-	-	-	45,299,134	11,395,652
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000								
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		86,371	-	-	-	-	-	313	53,086	13,355
Subtotal Labor Expenses	LBSUB		$ 2,996,018	$ 47,441	$ 22,425	$ 802,155	$ 62,356	$ -	$ 39,824	$ 912,319	$ 229,507
Subtotal O&M Expenses	OMSUB		$ 5,343,996	$ 159,564	$ 144,731	$ 1,101,109	$ 135,019	$ 41,893	$ 67,527	$ 1,432,752	$ 360,430

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Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Internally Generated Functional Vectors						
Sub-Total Distribution Plant		PTDSUB	0.127718	0.180832	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.077387	0.109570	-	-
Total Storage Plant		PTST	-	-	-	-
Transmission Plant		PT365	-	-	-	-
General Plant		PT389	0.077387	0.109570	-	-
Total Distribution Plant		PTDSUB	0.127718	0.180832	-	-
Sub-Total CWIP		CWIP	0.009865	0.013967	-	-
Total Depreciation Reserve		DEPR	0.073988	0.104757	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.077387	0.109570	-	-
Transmission and Distribution Payroll		LBTD	0.080976	0.120767	-	-
Transmission and Distribution Mains		TDMSUB	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-
Mains & Services	CADAL		10,856,853	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM					
Distribution Operation Expenses Subtotal	DOES		-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		1,631	17,986	-	-
Subtotal Labor Expenses	LBSUB		$ 207,563	$ 309,560	$ 362,869	$ -
Subtotal O&M Expenses	OMSUB		$ 318,490	$ 511,748	$ 1,068,529	$ 2,204

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Net Operating Income -- Adjusted Test Period (Cont.)											
Pro-Forma Adjustments to Expenses											
Labor Adjustment		EXADJ1	LBTT	$	(283,168)	$	(151,479)	$	(34,774)	$	(57,683)
Eliminate Advedrtising Expenses		EXADJ2	REVUC		(59,151)	$	(27,998)	$	(8,212)	$	(12,740)
Depreciation Expenses		EXADJ3	DET		(145,431)	$	(73,441)	$	(18,727)	$	(33,958)
Customer Deposits		EXADJ4	CSTDEP		33,554	$	30,095	$	3,006	$	329
Other Taxes		EXADJ5	OMTT		(15,767)	$	(8,643)	$	(1,937)	$	(3,193)
Rate Case Expenses		EXADJ6	OMTT		83,333	$	45,680	$	10,236	$	16,878
Total Expense Adjustments		ADJTOT		$	(386,630)	$	(185,786)	$	(50,408)	$	(90,367)
Net Income Before Income Taxes				$	8,471,112	$	3,140,136	$	1,401,997	$	1,825,421
Income Taxes			TXINC	$	1,565,326	$	361,162	$	319,376	$	311,705
Net Operating Income (Adjusted)		TOM		$	6,905,786	$	2,778,973	$	1,082,622	$	1,513,717
Net Cost Rate Base				$	111,071,658	$	56,221,672	$	14,507,681	$	26,517,789
Rate of Return -- Actual					6.22%		4.94%		7.46%		5.71%

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Net Operating Income -- Adjusted Test Period (Cont.)						
Pro-Forma Adjustments to Expenses						
Labor Adjustment		EXADJ1	LBTT	$ (11,719)	$ (9,532)	$ (17,982)
Eliminate Advedrtising Expenses		EXADJ2	REVUC	$ (4,194)	$ (1,554)	$ (4,453)
Depreciation Expenses		EXADJ3	DET	$ (5,968)	$ (4,669)	$ (8,669)
Customer Deposits		EXADJ4	CSTDEP	$ 124	$ -	$ -
Other Taxes		EXADJ5	OMTT	$ (618)	$ (480)	$ (896)
Rate Case Expenses		EXADJ6	OMTT	$ 3,267	$ 2,536	$ 4,736
Total Expense Adjustments		ADJTOT		$ (19,108)	$ (13,698)	$ (27,263)
Net Income Before Income Taxes				$ 1,074,152	$ 138,280	$ 891,125
Income Taxes			TXINC	$ 338,371	$ (1,869)	$ 236,581
Net Operating Income (Adjusted)		TOM		$ 735,781	$ 140,150	$ 654,544
Net Cost Rate Base				$ 4,291,840	$ 3,341,421	$ 6,191,257
Rate of Return -- Actual				17.14%	4.19%	10.57%

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Net Operating Income -- Adjusted For Increase							
Test Year Operating Income				$ 6,905,786	$ 2,778,973	$ 1,082,622	$ 1,513,717
Proposed Increase				$ 4,277,456	$ 2,658,496	$ 497,460	$ 922,000
Increase From Reconnection Charge			RCNCT	$ -	$ -	$ -	$ -
Total Increase				$ 4,277,456	$ 2,658,496	$ 497,460	$ 922,000
Incremental Income Taxes (@39.4445)				1,687,242	1,048,643	196,223	363,683
Net Operating Income Adjusted for Increase				9,496,000	4,388,826	1,383,859	2,072,034
Net Cost Rate Base				$ 111,071,658	$ 56,221,672	$ 14,507,681	$ 26,517,789
Rate of Return -- Proposed				8.55%	7.81%	9.54%	7.81%
Portion of Delta Proposed Increase				100.00%	62.15%	11.63%	21.55%

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Net Operating Income -- Adjusted For Increase						
Test Year Operating Income				$ 735,781	$ 140,150	$ 654,544
Proposed Increase				$ -	$ 199,500	$ -
Increase From Reconnection Charge			RCNCT	$ -	$ -	$ -
Total Increase				$ -	$ 199,500	$ -
Incremental Income Taxes (@39.4445)				-	78,693	-
Net Operating Income Adjusted for Increase				735,781	260,957	654,544
Net Cost Rate Base				$ 4,291,840	$ 3,341,421	$ 6,191,257
Rate of Return -- Proposed				17.14%	7.81%	10.57%
Portion of Delta Proposed Increase				0.00%	4.66%	0.00%

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Allocation Factors							
Commodity							
Procurement Expenses		COM01		15,674,258	2,294,517	697,273	2,087,953
					0.146388	0.044485	0.133209
Storage (Dec thru March)		COM02		3,364,406	1,682,504	523,849	1,158,053
Transmission		COM03		15,674,258	2,294,517	697,273	2,087,953
Distribution		COM04		6,658,703	2,294,517	697,273	2,087,953
				-	-	-	-
Demand							
Procurement Expenses		DEM01		85,209	29,049	8,663	18,079
Storage		DEM02		1.00000	0.507820	0.151874	0.340306
					0.507820	0.151874	0.340306
Transmission		DEM03		85,209	29,049	8,663	18,079
Distribution Structures		DEM04		60,509	29,049	8,663	18,079
Distribution Mains		DEM05		60,509	29,049	8,663	18,079
Customer							
Distribution Mains (Year-end Customers)		CUST01		39,695	34,100	4,629	928
Services		CUST02		13,957,247	10,162,823	2,792,167	960,842
Meters		CUST03		6,096,255	3,732,245	587,420	1,420,768
Customer Count (Average)				39,141	33,700	4,476	923
Customer Accounts		CUST04		42,156	33,700	4,476	3,692
Customer Service		CUST05		39,141	33,700	4,476	923
Forfeited Discounts		REVFD		2,641,717	2,168,773	432,108	9,080

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Allocation Factors						
Commodity						
Procurement Expenses		COM01		1,318,411	2,915,837	6,360,266
Storage (Dec thru March)		COM02		-	-	-
Transmission		COM03		1,318,411	2,915,837	6,360,266
Distribution		COM04		1,318,411	260,549	-
				-	-	-
Demand						
Procurement Expenses		DEM01		4,004	7,989	17,425
Storage		DEM02		-	-	-
Transmission		DEM03		4,004	7,989	17,425
Distribution Structures		DEM04		4,004	714	-
Distribution Mains		DEM05		4,004	714	-
Customer						
Distribution Mains (Year-end Customers)		CUST01		37	1	-
Services		CUST02		38,309	3,106	-
Meters		CUST03		314,722	41,100	-
Customer Count (Average)				38	4	-
Customer Accounts		CUST04		152	16	120
Customer Service		CUST05		38	4	-
Forfeited Discounts		REVFD		2,703	18,740	9,961

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Allocation Factors Continued							
Taxable Income Actual							
Net Income Before Income Tax		NIBIT		$ 8,471,112	$ 3,140,136	$ 1,401,997	$ 1,825,421
Interest Expense		INT	PLT	$ 4,562,696	$ 2,299,568	$ 587,709	$ 1,054,288
Interest Adjustment			PLT	$ (223,987)	$ (112,888)	$ (28,851)	$ (51,756)
Taxable Income		TXINC		$ 4,132,403	$ 953,456	$ 843,140	$ 822,890
Meter Allocation							
Number of Customers				39,697	34,100	4,629	928
Average Cost Per Service					109.45	126.9	1531
Meter Cost				6,096,255	3,732,245	587,420	1,420,768
Service Line Allocation							
Number of Customers				39,697	34,100	4,629	928
Average Cost Per Service					298.03	603.19	1035.39
Service Cost				13,957,247	10,162,823	2,792,167	960,842
Collection Fees		COLL		1.00000	0.89530	0.09444	0.01026
Reconnect Revenue		RCNCT		1.00000	0.83325	0.16052	0.00571
Bad Check Fees		BDCK		1.00000	0.90490	0.07877	0.01633
Customer Deposits		CSTDEP		1.00000	0.89690	0.08960	0.00980
Transmission Allocator							
Transmission Demand Allocator				85,209	29,049	8,663	18,079
Transmission Plant				$ 49,385,713			
Specific Assignment				$ 36,192.40			
Residual Transmission Plant			DEM03	49,349,520	$ 16,823,977	$ 5,017,250	$ 10,470,607
Total Allocation of Transmission Plant				$ 49,385,713	$ 16,823,976.56	$ 5,017,250.47	$ 10,470,607.33
Transmission Allocator		TDEM		1.000000	0.340664852	0.101593157	0.212016932

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Allocation Factors Continued						
Taxable Income Actual						
Net Income Before Income Tax		NIBIT		$ 1,074,152	$ 138,280	$ 891,125
Interest Expense		INT	PLT	$ 190,202	$ 150,609	$ 280,321
Interest Adjustment			PLT	$ (9,337)	$ (7,394)	$ (13,761)
Taxable Income		TXINC		$ 893,288	$ (4,935)	$ 624,565
Meter Allocation						
Number of Customers				37	3	-
Average Cost Per Service				8506	13700	
Meter Cost				314,722	41,100	-
Service Line Allocation						
Number of Customers				37	3	-
Average Cost Per Service				1035.39	1035.39	0
Service Cost				38,309	3,106	-
Collection Fees		COLL				
Reconnect Revenue		RCNCT		0.00052		
Bad Check Fees		BDCK				
Customer Deposits		CSTDEP		0.00370		
Transmission Allocator						
Transmission Demand Allocator				4,004	7,989	17,425
Transmission Plant						
Specific Assignment					$ 36,192.40	
Residual Transmission Plant			DEM03	$ 2,318,951	$ 4,626,898	$ 10,091,838
Total Allocation of Transmission Plant				$ 2,318,950.81	$ 4,663,090.01	$ 10,091,837.64
Transmission Allocator		TDEM		0.046955904	0.094421843	0.204347311

Exhibit DHBK-5

AG's Cost of Service Study

Allocation of Costs to Customer Classes

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Plant in Service							
Gas Supply Costs							
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -
Storage							
Demand	PTIS	PTISSD	DEM02	$ 17,895,600	$ 9,087,751	$ 2,717,876	$ 6,089,972
Commodity	PTIS	PTISSC	COM02	-	$ -	$ -	$ -
Total Storage				$ 17,895,600	$ 9,087,751	$ 2,717,876	$ 6,089,972
Transmission							
Demand	PTIS	PTISTD	TDEM	$ 49,385,713	$ 16,823,977	$ 5,017,250	$ 10,470,607
Commodity	PTIS	PTISTC	COM03	-	$ -	$ -	$ -
Total Transmission				$ 49,385,713	$ 16,823,977	$ 5,017,250	$ 10,470,607
Distribution Expenses							
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -
Distribution Structures & Equipment							
Demand	PTIS	PTISDSD	DEM04	$ 2,376,435	$ 1,140,877	$ 340,232	$ 710,038

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Plant in Service						
Gas Supply Costs						
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -
Storage						
Demand	PTIS	PTISSD	DEM02	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	$ -	$ -	$ -
Total Storage				$ -	$ -	$ -
Transmission						
Demand	PTIS	PTISTD	TDEM	$ 2,318,951	$ 4,663,090	$ 10,091,838
Commodity	PTIS	PTISTC	COM03	$ -	$ -	$ -
Total Transmission				$ 2,318,951	$ 4,663,090	$ 10,091,838
Distribution Expenses						
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -
Distribution Structures & Equipment						
Demand	PTIS	PTISDSD	DEM04	$ 157,254	$ 28,034	$ -

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Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Plant in Service (Continued)											
Distribution Mains											
Demand	PTIS	PTISDMD	DEM05	$	51,679,948	$	24,810,454	$	7,398,980	$	15,441,089
Customer	PTIS	PTISDMC	CUST01		13,000,838	$	11,168,373	$	1,516,082	$	303,937
Total Distribution Mains					64,680,786	$	35,978,828	$	8,915,062	$	15,745,026
Services											
Customer	PTIS	PTISSC	CUST02	$	12,386,144	$	9,018,841	$	2,477,865	$	852,684
Meters											
Customer	PTIS	PTISMC	CUST03	$	17,537,172	$	10,736,595	$	1,689,839	$	4,087,141
Customer Accounts											
Customer	PTIS	PTISCAC	CUST04	$	-	$	-	$	-	$	-
Customer Service											
Customer	PTIS	PTISCSC	CUST05	$	-	$	-	$	-	$	-
Total		PLT		$	164,261,851	$	82,786,868	$	21,158,125	$	37,955,470

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Plant in Service (Continued)						
Distribution Mains						
Demand	PTIS	PTISDMD	DEM05	$ 3,419,776	$ 609,649	$ -
Customer	PTIS	PTISDMC	CUST01	$ 12,118	$ 328	$ -
Total Distribution Mains				$ 3,431,894	$ 609,977	$ -
Services						
Customer	PTIS	PTISSC	CUST02	$ 33,997	$ 2,757	$ -
Meters						
Customer	PTIS	PTISMC	CUST03	$ 905,365	$ 118,233	$ -
Customer Accounts						
Customer	PTIS	PTISCAC	CUST04	$ -	$ -	$ -
Customer Service						
Customer	PTIS	PTISCSC	CUST05	$ -	$ -	$ -
Total		PLT		$ 6,847,460	$ 5,422,090	$ 10,091,838

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Rate Base							
Gas Supply Costs							
Demand	NCRB	RBGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -
Storage							
Demand	NCRB	RBSD	DEM02	$ 19,182,921	$ 9,741,479	$ 2,913,387	$ 6,528,055
Commodity	NCRB	RBSC	COM02	24,670	$ 12,337	$ 3,841	$ 8,492
Total Storage				$ 19,207,591	$ 9,753,816	$ 2,917,228	$ 6,536,547
Transmission							
Demand	NCRB	RBTD	TDEM	$ 30,238,664	$ 10,301,250	$ 3,072,041	$ 6,411,109
Commodity	NCRB	RBTC	COM03	28,284	$ 4,140	$ 1,258	$ 3,768
Total Transmission				$ 30,266,948	$ 10,305,391	$ 3,073,300	$ 6,414,877
Distribution Expenses							
Commodity	NCRB	RBDEC	COM04	$ 6,316	$ 2,176	$ 661	$ 1,980
Distribution Structures & Equipment							
Demand	NCRB	RBDSD	DEM04	$ 1,503,444	$ 721,772	$ 215,247	$ 449,203

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Rate Base						
Gas Supply Costs						
Demand	NCRB	RBGSD	DEM01	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -
Storage						
Demand	NCRB	RBSD	DEM02	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	$ -	$ -	$ -
Total Storage				$ -	$ -	$ -
Transmission						
Demand	NCRB	RBTD	TDEM	$ 1,419,884	$ 2,855,190	$ 6,179,190
Commodity	NCRB	RBTC	COM03	$ 2,379	$ 5,262	$ 11,477
Total Transmission				$ 1,422,263	$ 2,860,452	$ 6,190,667
Distribution Expenses						
Commodity	NCRB	RBDEC	COM04	$ 1,250	$ 247	$ -
Distribution Structures & Equipment						
Demand	NCRB	RBDSD	DEM04	$ 99,486	$ 17,736	$ -

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Rate Base (Continued)							
Distribution Mains							
Demand	NCRB	RBDMD	DEM05	$ 32,732,575	$ 15,714,219	$ 4,686,298	$ 9,779,936
Customer	NCRB	RBDMC	CUST01	8,234,352	$ 7,073,723	$ 960,242	$ 192,505
Total Distribution Mains				40,966,927	$ 22,787,942	$ 5,646,541	$ 9,972,441
Services							
Customer	NCRB	RBSC	CUST02	$ 7,814,021	$ 5,689,698	$ 1,563,206	$ 537,931
Meters							
Customer	NCRB	RBMC	CUST03	$ 11,098,851	$ 6,794,931	$ 1,069,458	$ 2,586,652
Customer Accounts							
Customer	NCRB	RBCAC	CUST04	$ 207,228	$ 165,660	$ 22,003	$ 18,149
Customer Service							
Customer	NCRB	RBCSC	CUST05	$ 332	$ 286	$ 38	$ 8
Total		RBT		$ 111,071,658	$ 56,221,672	$ 14,507,681	$ 26,517,789

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Rate Base (Continued)						
Distribution Mains						
Demand	NCRB	RBDMD	DEM05	$ 2,165,986	$ 386,134	$ -
Customer	NCRB	RBDMC	CUST01	$ 7,675	$ 207	$ -
Total Distribution Mains				$ 2,173,662	$ 386,342	$ -
Services						
Customer	NCRB	RBSC	CUST02	$ 21,448	$ 1,739	$ -
Meters						
Customer	NCRB	RBMC	CUST03	$ 572,983	$ 74,827	$ -
Customer Accounts						
Customer	NCRB	RBCAC	CUST04	$ 747	$ 79	$ 590
Customer Service						
Customer	NCRB	RBCSC	CUST05	$ 0	$ 0	$ -
Total		RBT		$ 4,291,840	$ 3,341,421	$ 6,191,257

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Operation and Maintenance Expenses							
Gas Supply Costs							
Demand	OMT	OMGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -	$ -
Storage							
Demand	OMT	OMSD	DEM02	$ 334,139	$ 169,683	$ 50,747	$ 113,709
Commodity	OMT	OMSC	COM02	201,674	$ 100,855	$ 31,401	$ 69,418
Total Storage		OMST		$ 535,813	$ 270,537	$ 82,148	$ 183,127
Transmission							
Demand	OMT	OMTD	TDEM	$ 2,451,016	$ 834,975	$ 249,006	$ 519,657
Commodity	OMT	OMTC	COM03	231,211	$ 33,846	$ 10,285	$ 30,799
Total Transmission		OMTRT		$ 2,682,227	$ 868,822	$ 259,292	$ 550,456
Distribution Expenses							
Commodity	OMT	OMDEC	COM04	$ 51,629	$ 17,791	$ 5,406	$ 16,189
Distribution Structures & Equipment							
Demand	OMT	OMDSD	DEM04	$ 136,861	$ 65,704	$ 19,594	$ 40,892

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Operation and Maintenance Expenses						
Gas Supply Costs						
Demand	OMT	OMGSD	DEM01	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -
Storage						
Demand	OMT	OMSD	DEM02	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	$ -	$ -	$ -
Total Storage		OMST		$ -	$ -	$ -
Transmission						
Demand	OMT	OMTD	TDEM	$ 115,090	$ 231,429	$ 500,859
Commodity	OMT	OMTC	COM03	$ 19,448	$ 43,011	$ 93,820
Total Transmission		OMTRT		$ 134,538	$ 274,441	$ 594,679
Distribution Expenses						
Commodity	OMT	OMDEC	COM04	$ 10,222	$ 2,020	$ -
Distribution Structures & Equipment						
Demand	OMT	OMDSD	DEM04	$ 9,056	$ 1,615	$ -

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Operation and Maintenance Expenses (Continued)							
Distribution Mains							
Demand	OMT	OMDMD	DEM05	$ 2,980,803	$ 1,431,021	$ 426,759	$ 890,613
Customer	OMT	OMDMC	CUST01	749,864	$ 644,171	$ 87,445	$ 17,531
Total Distribution Mains				3,730,667	$ 2,075,192	$ 514,204	$ 908,144
Services							
Customer	OMT	OMSC	CUST02	$ 672,088	$ 489,374	$ 134,452	$ 46,268
Meters							
Customer	OMT	OMMC	CUST03	$ 1,042,823	$ 638,436	$ 100,484	$ 243,036
Customer Accounts							
Customer	OMT	OMCAC	CUST04	$ 1,694,025	$ 1,354,224	$ 179,867	$ 148,362
Customer Service							
Customer	OMT	OMCSC	CUST05	$ 2,716	$ 2,338	$ 311	$ 64
Total		OMTT		$ 10,548,848	$ 5,782,417	$ 1,295,758	$ 2,136,537

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Operation and Maintenance Expenses (Continued)						
Distribution Mains						
Demand	OMT	OMDMD	DEM05	$ 197,246	$ 35,163	$ -
Customer	OMT	OMDMC	CUST01	$ 699	$ 19	$ -
Total Distribution Mains				$ 197,945	$ 35,182	$ -
Services						
Customer	OMT	OMSC	CUST02	$ 1,845	$ 150	$ -
Meters						
Customer	OMT	OMMC	CUST03	$ 53,836	$ 7,031	$ -
Customer Accounts						
Customer	OMT	OMCAC	CUST04	$ 6,108	$ 643	$ 4,822
Customer Service						
Customer	OMT	OMCSC	CUST05	$ 3	$ 0	$ -
Total		OMTT		$ 413,553	$ 321,081	$ 599,501

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Payroll Expenses							
Gas Supply Costs							
Demand	LBTOT	LBGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	LBTOT	LBGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses		LBGST		$ -	$ -	$ -	$ -
Storage							
Demand	LBTOT	LBSD	DEM02	$ 94,646	$ 48,063	$ 14,374	$ 32,208
Commodity	LBTOT	LBSC	COM02	44,739	$ 22,373	$ 6,966	$ 15,399
Total Storage		LBST		$ 139,384	$ 70,436	$ 21,340	$ 47,608
Transmission							
Demand	LBTOT	LBTD	TDEM	$ 1,600,320	$ 545,173	$ 162,582	$ 339,295
Commodity	LBTOT	LBTC	COM03	124,401	$ 18,211	$ 5,534	$ 16,571
Total Transmission		LBTRT		$ 1,724,721	$ 563,384	$ 168,116	$ 355,866
Distribution Expenses							
Commodity	LBTOT	LBDEC	COM04	$ -	$ -	$ -	$ -
Distribution Structures & Equipment							
Demand	LBTOT	LBDSD	DEM04	$ 79,449	$ 38,142	$ 11,375	$ 23,738

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Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Payroll Expenses						
Gas Supply Costs						
Demand	LBTOT	LBGSD	DEM01	$ -	$ -	$ -
Commodity	LBTOT	LBGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses		LBGST		$ -	$ -	$ -
Storage						
Demand	LBTOT	LBSD	DEM02	$ -	$ -	$ -
Commodity	LBTOT	LBSC	COM02	$ -	$ -	$ -
Total Storage		LBST		$ -	$ -	$ -
Transmission						
Demand	LBTOT	LBTD	TDEM	$ 75,144	$ 151,105	$ 327,021
Commodity	LBTOT	LBTC	COM03	$ 10,464	$ 23,142	$ 50,479
Total Transmission		LBTRT		$ 85,608	$ 174,247	$ 377,500
Distribution Expenses						
Commodity	LBTOT	LBDEC	COM04	$ -	$ -	$ -
Distribution Structures & Equipment						
Demand	LBTOT	LBDSD	DEM04	$ 5,257	$ 937	$ -

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Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Payroll Expenses							
Distribution Mains							
Demand	LBTOT	LBDMD	DEM05	$ 1,820,100	$ 873,792	$ 260,582	$ 543,815
Customer	LBTOT	LBDMC	CUST01	457,872	$ 393,335	$ 53,394	$ 10,704
Total Distribution Mains				2,277,972	$ 1,267,127	$ 313,977	$ 554,519
Services							
Customer	LBTOT	LBSC	CUST02	$ 414,094	$ 301,518	$ 82,840	$ 28,507
Meters							
Customer	LBTOT	LBMC	CUST03	$ 617,580	$ 378,095	$ 59,509	$ 143,931
Customer Accounts							
Customer	LBTOT	LBCAC	CUST04	$ 723,934	$ 578,721	$ 76,865	$ 63,402
Customer Service							
Customer	LBTOT	LBCSC	CUST05	$ -	$ -	$ -	$ -
Total		LBTT		$ 5,977,135	$ 3,197,423	$ 734,021	$ 1,217,571

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Payroll Expenses						
Distribution Mains						
Demand	LBTOT	LBDMD	DEM05	$ 120,440	$ 21,471	$ -
Customer	LBTOT	LBDMC	CUST01	$ 427	$ 12	$ -
Total Distribution Mains				$ 120,867	$ 21,483	$ -
Services						
Customer	LBTOT	LBSC	CUST02	$ 1,137	$ 92	$ -
Meters						
Customer	LBTOT	LBMC	CUST03	$ 31,883	$ 4,164	$ -
Customer Accounts						
Customer	LBTOT	LBCAC	CUST04	$ 2,610	$ 275	$ 2,061
Customer Service						
Customer	LBTOT	LBCSC	CUST05	$ -	$ -	$ -
Total		LBTT		$ 247,362	$ 201,198	$ 379,561

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Depreciation Expenses							
Gas Supply Costs							
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -
Storage							
Demand	DEPREX	DESD	DEM02	$ 526,004	$ 267,116	$ 79,886	$ 179,002
Commodity	DEPREX	DESC	COM02	-	$ -	$ -	$ -
Total Storage		DEST		$ 526,004	$ 267,116	$ 79,886	$ 179,002
Transmission							
Demand	DEPREX	DETD	TDEM	$ 1,222,322	$ 416,402	$ 124,180	$ 259,153
Commodity	DEPREX	DETC	COM03	-	$ -	$ -	$ -
Total Transmission		DETT		$ 1,222,322	$ 416,402	$ 124,180	$ 259,153
Distribution Expenses							
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -
Distribution Structures & Equipment							
Demand	DEPREX	DEDSD	DEM04	$ 57,872	$ 27,783	$ 8,285	$ 17,291

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Depreciation Expenses						
Gas Supply Costs						
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses		DEGST		$ -	$ -	$ -
Storage						
Demand	DEPREX	DESD	DEM02	$ -	$ -	$ -
Commodity	DEPREX	DESC	COM02	$ -	$ -	$ -
Total Storage		DEST		$ -	$ -	$ -
Transmission						
Demand	DEPREX	DETD	TDEM	$ 57,395	$ 115,414	$ 249,778
Commodity	DEPREX	DETC	COM03	$ -	$ -	$ -
Total Transmission		DETT		$ 57,395	$ 115,414	$ 249,778
Distribution Expenses						
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -
Distribution Structures & Equipment						
Demand	DEPREX	DEDSD	DEM04	$ 3,829	$ 683	$ -

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Depreciation Expenses (Continued)											
Distribution Mains											
Demand	DEPREX	DEDMD	DEM05	$	1,279,490	$	614,256	$	183,184	$	382,290
Customer	DEPREX	DEDMC	CUST01		321,874	$	276,506	$	37,535	$	7,525
Total Distribution Mains					1,601,364	$	890,762	$	220,719	$	389,815
Services											
Customer	DEPREX	DESC	CUST02	$	299,868	$	218,346	$	59,989	$	20,643
Meters											
Customer	DEPREX	DEMC	CUST03	$	483,074	$	295,747	$	46,548	$	112,583
Customer Accounts											
Customer	DEPREX	DECAC	CUST04	$	-	$	-	$	-	$	-
Customer Service											
Customer	DEPREX	DECSC	CUST05	$	-	$	-	$	-	$	-
Total		DET		$	4,190,504	$	2,116,156	$	539,607	$	978,488

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Depreciation Expenses (Continued)						
Distribution Mains						
Demand	DEPREX	DEDMD	DEM05	$ 84,667	$ 15,094	$ -
Customer	DEPREX	DEDMC	CUST01	$ 300	$ 8	$ -
Total Distribution Mains				$ 84,967	$ 15,102	$ -
Services						
Customer	DEPREX	DESC	CUST02	$ 823	$ 67	$ -
Meters						
Customer	DEPREX	DEMC	CUST03	$ 24,939	$ 3,257	$ -
Customer Accounts						
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -
Customer Service						
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -
Total		DET		$ 171,953	$ 134,522	$ 249,778

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Other Taxes							
Gas Supply Costs							
Demand	OTT	OTTGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses		OTTGST		$ -	$ -	$ -	$ -
Storage							
Demand	OTT	OTTSD	DEM02	$ 116,254	$ 59,036	$ 17,656	$ 39,562
Commodity	OTT	OTTSC	COM02	3,901	$ 1,951	$ 607	$ 1,343
Total Storage		OTTST		$ 120,154	$ 60,987	$ 18,263	$ 40,904
Transmission							
Demand	OTT	OTTTD	TDEM	$ 445,711	$ 151,838	$ 45,281	$ 94,498
Commodity	OTT	OTTTC	COM03	10,846	$ 1,588	$ 482	$ 1,445
Total Transmission		OTTTT		$ 456,557	$ 153,426	$ 45,764	$ 95,943
Distribution Expenses							
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -
Distribution Structures & Equipment							
Demand	OTT	OTTDSD	DEM04	$ 21,265	$ 10,209	$ 3,044	$ 6,353

Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Other Taxes						
Gas Supply Costs						
Demand	OTT	OTTGSD	DEM01	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses		OTTGST		$ -	$ -	$ -
Storage						
Demand	OTT	OTTSD	DEM02	$ -	$ -	$ -
Commodity	OTT	OTTSC	COM02	$ -	$ -	$ -
Total Storage		OTTST		$ -	$ -	$ -
Transmission						
Demand	OTT	OTTTD	TDEM	$ 20,929	$ 42,085	$ 91,080
Commodity	OTT	OTTTC	COM03	$ 912	$ 2,018	$ 4,401
Total Transmission		OTTTT		$ 21,841	$ 44,102	$ 95,481
Distribution Expenses						
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -
Distribution Structures & Equipment						
Demand	OTT	OTTDSD	DEM04	$ 1,407	$ 251	$ -

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Other Taxes (Continued)											
Distribution Mains											
Demand	OTT	OTTDMD	DEM05	$	471,135	$	226,182	$	67,452	$	140,767
Customer	OTT	OTTDMC	CUST01		118,521	$	101,815	$	13,821	$	2,771
Total Distribution Mains					589,656	$	327,998	$	81,273	$	143,538
Services											
Customer	OTT	OTTSC	CUST02	$	110,832	$	80,701	$	22,172	$	7,630
Meters											
Customer	OTT	OTTMC	CUST03	$	159,651	$	97,741	$	15,384	$	37,208
Customer Accounts											
Customer	OTT	OTTCAC	CUST04	$	63,117	$	50,456	$	6,702	$	5,528
Customer Service											
Customer	OTT	OTTCSC	CUST05	$	-	$	-	$	-	$	-
Total		OTTT		$	1,521,231	$	781,517	$	192,602	$	337,104

Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Other Taxes (Continued)						
Distribution Mains						
Demand	OTT	OTTDMD	DEM05	$ 31,176	$ 5,558	$ -
Customer	OTT	OTTDMC	CUST01	$ 110	$ 3	$ -
Total Distribution Mains				$ 31,287	$ 5,561	$ -
Services						
Customer	OTT	OTTSC	CUST02	$ 304	$ 25	$ -
Meters						
Customer	OTT	OTTMC	CUST03	$ 8,242	$ 1,076	$ -
Customer Accounts						
Customer	OTT	OTTCAC	CUST04	$ 228	$ 24	$ 180
Customer Service						
Customer	OTT	OTTCSC	CUST05	$ -	$ -	$ -
Total		OTTT		$ 63,309	$ 51,039	$ 95,660

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Interest Expense							
Gas Supply Costs							
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -
Storage							
Demand	INT	INTSD	DEM02	$ 492,725	$ 250,216	$ 74,832	$ 167,677
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -
Total Storage		INTST		$ 492,725	$ 250,216	$ 74,832	$ 167,677
Transmission							
Demand	INT	INTTD	TDEM	$ 1,396,878	$ 475,867	$ 141,913	$ 296,162
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -
Total Transmission		INTTT		$ 1,396,878	$ 475,867	$ 141,913	$ 296,162
Distribution Expenses							
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -
Distribution Structures & Equipment							
Demand	INT	INTDSD	DEM04	$ 65,411	$ 31,403	$ 9,365	$ 19,544

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Interest Expense						
Gas Supply Costs						
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -
Storage						
Demand	INT	INTSD	DEM02	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	$ -	$ -	$ -
Total Storage		INTST		$ -	$ -	$ -
Transmission						
Demand	INT	INTTD	TDEM	$ 65,592	$ 131,896	$ 285,448
Commodity	INT	INTTC	COM03	$ -	$ -	$ -
Total Transmission		INTTT		$ 65,592	$ 131,896	$ 285,448
Distribution Expenses						
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -
Distribution Structures & Equipment						
Demand	INT	INTDSD	DEM04	$ 4,328	$ 772	$ -

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Interest Expense (Continued)											
Distribution Mains											
Demand	INT	INTDMD	DEM05	$	1,425,451	$	684,329	$	204,081	$	425,900
Customer	INT	INTDMC	CUST01		358,593	$	308,049	$	41,817	$	8,383
Total Distribution Mains					1,784,044	$	992,378	$	245,898	$	434,284
Services											
Customer	INT	INTSC	CUST02	$	340,928	$	248,243	$	68,203	$	23,470
Meters											
Customer	INT	INTMC	CUST03	$	482,710	$	295,524	$	46,513	$	112,498
Customer Accounts											
Customer	INT	INTCAC	CUST04	$	-	$	-	$	-	$	-
Customer Service											
Customer	INT	INTCSC	CUST05	$	-	$	-	$	-	$	-
Total		INTT		$	4,562,696	$	2,293,631	$	586,724	$	1,053,635

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Interest Expense (Continued)						
Distribution Mains						
Demand	INT	INTDMD	DEM05	$ 94,325	$ 16,816	$ -
Customer	INT	INTDMC	CUST01	$ 334	$ 9	$ -
Total Distribution Mains				$ 94,659	$ 16,825	$ -
Services						
Customer	INT	INTSC	CUST02	$ 936	$ 76	$ -
Meters						
Customer	INT	INTMC	CUST03	$ 24,920	$ 3,254	$ -
Customer Accounts						
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -
Customer Service						
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -
Total		INTT		$ 190,435	$ 152,822	$ 285,448

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Residential (GS)		Large Non-Residential (GS)
Net Operating Income -- Adjusted Test Period											
Operating Revenues											
Sales and Transportation		REVUC	R01		24,027,143		11,372,680		3,335,865		5,174,898
Collection Fees		COLFEE	COLL	$	115,305	$	103,233	$	10,889	$	1,183
Reconnect Revenue		RCTREV	RCNCT		76,980	$	64,144	$	12,357	$	440
Bad Check Revenue		BDCH	BDCK		9,890	$	8,949	$	779	$	162
Total Operating Revenues -- Per Books		TOR		$	24,229,318	$	11,549,006	$	3,359,890	$	5,176,682
Pro-Forma Adjustments to Revenues											
Temperature normalization		REVADJ1		$	115,747	$	85,434	$	19,666	$	10,501
Total Revenue Adjustments				$	115,747	$	85,434	$	19,666	$	10,501
Total Adjusted Revenue				$	24,345,065	$	11,634,440	$	3,379,556	$	5,187,183
Expenses											
Operation and Maintenance Expenses				$	10,548,848	$	5,782,417	$	1,295,758	$	2,136,537
Depreciation and Amortization Expenses					4,190,504		2,116,156		539,607		978,488
Other Taxes					1,521,231		781,517		192,602		337,104
Total Operating Expenses		TOE		$	16,260,583	$	8,680,090	$	2,027,967	$	3,452,129

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Cost of Service Study
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Net Operating Income -- Adjusted Test Period						
Operating Revenues						
Sales and Transportation		REVUC	R01	1,703,673	631,225	1,808,801
Collection Fees		COLFEE	COLL	$ -	$ -	$ -
Reconnect Revenue		RCTREV	RCNCT	$ 40	$ -	$ -
Bad Check Revenue		BDCH	BDCK	$ -	$ -	$ -
Total Operating Revenues -- Per Books		TOR		$ 1,703,714	$ 631,225	$ 1,808,801
Pro-Forma Adjustments to Revenues						
Temperature normalization		REVADJ1		$ 146	$ -	$ -
Total Revenue Adjustments				$ 146	$ -	$ -
Total Adjusted Revenue				$ 1,703,860	$ 631,225	$ 1,808,801
Expenses						
Operation and Maintenance Expenses				$ 413,553	$ 321,081	$ 599,501
Depreciation and Amortization Expenses				171,953	134,522	249,778
Other Taxes				63,309	51,039	95,660
Total Operating Expenses		TOE		$ 648,815	$ 506,642	$ 944,940

Exhibit DHBK-6

AG's Cost of Service Study
with
AG Recommended Rate Increase

Allocation of Costs
to Customer Classes

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
Using Attorney General's Proposed Rate Increase
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Net Operating Income -- Adjusted For Increase							
Test Year Operating Income				$ 6,905,786	$ 2,778,973	$ 1,082,622	$ 1,513,717
Proposed Increase				$ 1,364,420	$ 848,005	$ 158,679	$ 294,099
Increase From Reconnection Charge			RCNCT	$ -	$ -	$ -	$ -
Total Increase				$ 1,364,420	$ 848,005	$ 158,679	$ 294,099
Incremental Income Taxes (@39.4445)				538,195	334,496	62,591	116,007
Net Operating Income Adjusted for Increase				7,732,011	3,292,483	1,178,710	1,691,808
Net Cost Rate Base				$ 111,071,658	$ 56,221,672	$ 14,507,681	$ 26,517,789
Rate of Return -- Proposed				6.96%	5.86%	8.12%	6.38%
Portion of Attorney General Proposed Increase				100.00%	62.15%	11.63%	21.55%

OFFICE OF THE ATTORNEY GENERAL
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Cost of Service Study
Using Attorney General's Proposed Rate Increase
12 Months Ended December 31, 2003

Class Allocation

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Net Operating Income -- Adjusted For Increase						
Test Year Operating Income				$ 735,781	$ 140,150	$ 654,544
Proposed Increase				$ -	$ 63,636	$ -
Increase From Reconnection Charge			RCNCT	$ -	$ -	$ -
Total Increase				$ -	$ 63,636	$ -
Incremental Income Taxes (@39.4445)				-	25,101	-
Net Operating Income Adjusted for Increase				735,781	178,685	654,544
Net Cost Rate Base				$ 4,291,840	$ 3,341,421	$ 6,191,257
Rate of Return -- Proposed				17.14%	5.35%	10.57%
Portion of Attorney General Proposed Increase				0.00%	4.66%	0.00%

Exhibit DHBK-7

Calculation of
Monthly Customer Charge

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
Using Attorney General's Proposed Rate Increase
12 Months Ended December 31, 2003

Calculation of Monthly Customer Charge

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Customer Related							
Rate Base				$ 19,120,432	$ 12,650,575	$ 2,654,704	$ 3,142,740
Rate of Return				6.96%	6.10%	8.13%	6.12%
Return				$ 1,331,027	$ 771,470	$ 215,768	$ 192,490
Income Taxes				$ 291,137	$ 103,464	$ 70,816	$ 28,830
Operation and Maintenance Expenses				2,933,075	2,101,792	364,299	395,816
Depreciation Expenses				782,942	514,093	106,537	133,227
Other Taxes				333,599	228,899	44,257	50,365
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				(103,968)	(71,587)	(13,754)	(14,715)
Total Customer-Related Revenue Requirement				$ 5,567,813	$ 3,648,131	$ 787,923	$ 786,013
Less: Misc Service Revenues				(18,321)	(21,260)	(3,110)	(63)
Net Revenue Requirement				$ 5,549,493	$ 3,626,871	$ 784,814	$ 785,951
Customer-Months				39,141	33,700	4,476	923
Customer-Related Unit Cost ($/Cust/Mo)				11.815	8.969	14.612	70.960

OFFICE OF THE ATTORNEY GENERAL
Delta Natural Gas - Case No. 2004-00067

Cost of Service Study
Using Attorney General's Proposed Rate Increase
12 Months Ended December 31, 2003

Calculation of Monthly Customer Charge

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Customer Related						
Rate Base				$ 595,179	$ 76,644	$ 590
Rate of Return				15.79%	5.00%	10.59%
Return				$ 93,970	$ 3,833	$ 62
Income Taxes				$ 81,206	$ (149)	$ 34
Operation and Maintenance Expenses				60,066	7,642	3,460
Depreciation Expenses				25,762	3,324	-
Other Taxes				8,774	1,125	180
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				(2,367)	(314)	(106)
Total Customer-Related Revenue Requirement				$ 267,410	$ 15,461	$ 3,631
Less: Misc Service Revenues				(8)	-	-
Net Revenue Requirement				$ 267,403	$ 15,461	$ 3,631
Customer-Months				38	4	-
Customer-Related Unit Cost ($/Cust/Mo)				586.409	322.095	