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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS CO., INC. FOR AN ADJUSTMENT OF GAS RATES	)))	Case No. 2007-00089

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the Attorney General's Testimony were served and filed by hand delivery to Beth O'Donnell, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to:

Hon. Robert M. Watt, III
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all on this 14th day of August, 2007.

Lawrence W. Cook
Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

Direct Testimony of
Michael J. Majoros, Jr.

on Behalf of
the Office of the Attorney General

August 14, 2007

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<u>Introduction</u>

Q. 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"), located at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of twelve economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation, and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 37-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. Appendix B 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").

<u>Subject and Purpose of Testimony</u>

Q. What is the subject of your testimony?

A. This case involves Delta Natural Gas Company, Inc.'s ("Delta") Application to increase its service rates by $5,641,597 million or 9.25 percent.[1] The Company subsequently reduced its request slightly, to $5,640,680 million.[2] My testimony addresses the Company's filing including its depreciation proposals.

<u>Prior Experience</u>

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

A. Yes, I have been in the field of public utility regulation since the late 1970's. My testimony has encompassed numerous complex cost of service issues. Furthermore, 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.

<u>Summary of Company's Filing</u>

Q. Summarize the Company's filing.

A. Delta cites to reduced consumption by customers, increases to gas plant in service, and increases to operations and maintenance expense, particularly pension and healthcare benefits, as the reasons it has been unable to earn its authorized return.[3] Delta proposes the twelve months ended December 31, 2006 as its historical test period. The Company

[1] Direct Testimony of John Brown ("Brown"), p. 4.
[2] Response to PSC 2-6d.
[3] Filing Requirement 807 KAR 5:001 Section 10(1)(a)1.

has also proposed two new programs; a Customer Rate Stabilization ("CRS") mechanism and a Customer Conservation and Efficiency Program ("CEP").[4] I will address the overall revenue requirement in my testimony. Dr. Woolridge will address cost of capital, and Charles W. King and Robert Henkes will address respectively the rate design, conservation, and rate stabilization programs.

Q. Why did Delta reduce its request?

A. Delta provided a revised request in response to PSC Data Request Item 6d. In its response, the Company revised Schedule 5 to comply with a Staff request to reflect the correct FICA base wage limit, and Schedule 7 to correctly include the PSC assessment as a component of the tax expansion factor. It also revised Schedule 6 to "put cost of removal back with accumulated depreciation where it belongs for ratemaking purposes." As I will discuss below, the Company's correction of the cost of removal issue has additional implications. The net impact of these revisions was a $110,557 reduction to Delta's proposed revenue requirement.[5]

In addition to the revisions noted above, the Company took this opportunity to make several additional revisions, including one to property taxes, one to medical expense and one to legal expense. These revisions resulted in a $109,640 increase to the revenue requirement.[6] The net of the adjustments was a $917 reduction to the revenue deficiency.

Q. Do you have an overall critique of Delta's filing?

A. While some mistakes occur in applications, I feel that Delta's filing contains quite a few.

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[4] Id.
[5] Response to PSC DR 2-6d, Schedule 10.
[6] Id.

In particular, I am not convinced that the Company gave sufficient scrutiny to the depreciation study it filed.

<u>Case No. 2004-00067</u>

Q. Have you reviewed the Commission's Order in Case No. 2004-00067?

A. Yes, I have reviewed the Commission's Order in Case No. 2004-00067. I participated in that case as the Attorney General's depreciation witness.

<u>Summary of Conclusions</u>

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. The company has an overall cost of capital of 7.64 percent.
2. The Company has a pro-forma test period rate base of $117,817,218.
3. The Company has pro-forma test period operating income of $5,580,631 at present rates.
4. Delta's test period revenue deficiency is $3,417,318 in contrast to its claimed $5,640,680 revenue deficiency.

<u>Summary Explanation of Exhibits</u>

Q. Please summarize and explain the structure of your exhibits.

A. I have four exhibits consisting of varying numbers of schedules. Exhibit___(MJM-1) contains my summary schedules. Exhibit___(MJM-2) is a one-page exhibit containing Dr. Woolridge's Cost of Capital recommendations. Exhibit___(MJM-3) contains my rate base exhibits. These include a summary and my individual Adjustment Nos. 1 and 2. Exhibit___(MJM-4) contains my operating income adjustments, which I have labeled

Adjustment Nos. 3 to 18. Exhibit___ (MJM-5) contains my depreciation studies. I have summarized all of the rate base and operating income adjustments, including their individual revenue requirement impacts on Exhibit___ (MJM-1), Schedule 2.

<u>**Cost of Capital**</u>

Q. What overall cost of capital did you use to calculate your proposed revenue requirement?

A. I used Dr. Woolridge's recommended capital structure and cost rates as summarized in Exhibit___ (MJM-2).

<u>**Tax Rates and Conversion Factors**</u>

Q. Please summarize and explain the income tax rates and conversion factors you used in your analyses.

A. I used all of Delta's tax and conversion factors.

<u>**Adjustment Nos. 1 and 2 - Rate Base Adjustments**</u>

Q. Please explain your rate base adjustments.

A. I made two adjustments to Delta's rate base claim. My Adjustment No. 1 decreases accumulated depreciation corresponding to my depreciation rate and expense decrease adjustment. I have limited my adjustment to a reversal of Delta's rate base reduction for Mr. Seelye's proposed depreciation increase. My Adjustment No. 2 reduces the cash working capital component of rate base in conjunction with my expense adjustments.

Q. Do you have any other comments concerning rate base?

A. Yes, I do. A major portion of Delta's update was to reclassify an $831,877 Regulatory Liability into accumulated depreciation. This Regulatory Liability resulted from prior charges to ratepayers, in the form of higher depreciation expense for future removal costs for which Delta does not have any corresponding legal liability to spend the money. The Federal Energy Regulatory Commission ("FERC") defined these amounts as non-legal asset retirement obligations ("AROs"). The public accounting profession's generally accepted accounting principles ("GAAP") and the Securities and Exchange Commission ("SEC") require reporting this amount as a liability to ratepayers.

The amount was originally included in accumulated depreciation, which reduces rate base. Consistent with GAAP and SEC rules, Delta reclassified the amount to a Regulatory Liability. It failed, however, to reduce its rate base by the Regulatory Liability in its original filing. Without any other changes, I merely would have proposed that the Regulatory Liability be subtracted from rate base as it should be, and perhaps amortized back to ratepayers over the average remaining life of the corresponding plant. This recommendation would have resolved an issue that has arisen in several recent Kentucky cases in which I have testified. It would have enabled the Commission to recognize this amount as Regulatory Liability. In certain prior cases the Commission has chosen not to recognize this amount as a Regulatory Liability, however, in my opinion, this case provides an ideal opportunity to reconsider the issue.

Q. Do you have any other comments about this issue?

A. Yes, I do. While Delta transferred the regulatory liability into accumulated depreciation for rate base purposes, it failed to adjust its depreciation study for the reclassification. That has an impact on depreciation rates because Delta uses the remaining life depreciation technique to calculate depreciation. The remaining life technique incorporates the accumulated depreciation balances into the depreciation rate calculations. In this case, Delta failed to recognize its reclassification in the depreciation study, which in turn resulted in overstated depreciation rates. I have corrected that mistake, but again, should the Commission decide to recognize the Regulatory Liability as a separate amount, this correction is not necessary.

The Commission has two options for this adjustment. The first alternative merely allows the amount to remain as a Regulatory Liability and reduce rate base by that amount. In conjunction with this approach, the Commission could amortize the regulatory liability over the remaining life of the plant, which is what will happen if it is included in accumulated depreciation. The second alternative is to accept Delta's transfer; however, a corresponding recalculation of Delta's depreciation rates is required to account for the additional reserve amount. I have used the second alternative in my exhibits.

Operating Income Adjustments

Q. Will you please explain your operating income adjustments?

A. Yes, I will. As you can see by referring to my Exhibit___ (MJM-1) Schedule 2, I have arranged my adjustments by order of magnitude from the largest to the smallest in terms of dollars.

Adjustment No. 3 - Depreciation Expense

Q. Please explain your Adjustment No. 3.

A. Mr. Seelye conducted a depreciation study which resulted in his proposed $292,968 depreciation expense increase. My Adjustment No. 3 reduces the Company's overall depreciation expense request by $972,418 for several reasons. It incorporates changes and adjustments to Mr. Seeley's proposed depreciation rates and a disallowance of depreciation expense on construction work in progress ("CWIP").

Q. What adjustments did you make to Delta's depreciation expense request?

A. I made several adjustments to Delta's depreciation expense request. First, I added the Company's Regulatory Liability for non-legal AROs back into accumulated depreciation for rate calculation purposes. Second, I have corrected several errors in Mr. Seelye's calculations. I also studied the lives of three accounts that were at issue in Case No. 2004-00067, and changed the depreciation rates accordingly. Finally, as stated above, I have removed the proposed depreciation expense on construction work in progress ("CWIP").

Q. Describe the Company's Depreciation Study.

A. Mr. Seelye conducted Delta's Depreciation Study. Mr. Seelye alleges that he used the "average service life depreciation procedure, the straight-line method, and the remaining life basis" to calculate depreciation rates.[7] That is correct for those particular accounts where he actually calculated a depreciation rate. For other accounts, Mr. Seelye either retained the existing depreciation rates or reduced them based on his judgment. Mr. Seelye did not perform net salvage analyses in conjunction with his study. He proposes the same net salvage ratios he proposed and which the Commission accepted in Case No. 2004-00067.

[7] Seelye Exhibit 11, p. 2.

Q. Why did you add the Company's Regulatory Liability for non-legal AROs back into accumulated depreciation?

A. As mentioned above, Mr. Seelye used the remaining life technique for those accounts where he actually calculated a depreciation rate. The depreciation reserve is a primary component of a remaining life depreciation rate calculation. Mr. Seelye did not use the Company's entire depreciation reserve to calculate his rates. He inadvertently excluded the reserve for non-legal cost of removal, which Delta had reclassified as a Regulatory Liability.[8]

I added Delta's Regulatory Liability back to the accumulated depreciation balances used in the depreciation study, consistent with Delta's rate base reclassification in its updated filing. This adjustment reduces some of the resulting depreciation rates and expense because the additional reserve is effectively flowed back to ratepayers over the remaining life of the plant. Normally it would reduce all of the rates for the accounts involved. However, in the case of account 380 – Distribution Services, Mr. Seelye used his proposed rate for account 376 - Distribution Mains, as opposed to calculating a separate rate for Distribution Services. Therefore, even though there is a large cost of removal reserve associated with this account, the add back did not affect the resulting rate due to Mr. Seelye's approach for this account.

Q. Do you have any other comments concerning Mr. Seelye's recommendations for account 376 – Distribution Mains and account 380 - Distribution Services?

[8] Response to AG Data Request 2-13.

A. Yes, Account – 376 - Distribution Mains is Delta's single largest plant account. It is one of the three accounts I challenged in Case No. 2004-00067. I proposed a 52-year life rather than Mr. Seelye's 37-year proposal. In that case, Mr. Seelye used the simulated plant records ("SPR") and the geometric mean turnover ("GMT") methods to study plant lives. I conducted similar analyses and identified three accounts where Mr. Seelye's recommendations were not supported by any of the analyses. Consequently, I made alternative recommendations based on my own analyses. The Commission rejected my recommendations because I refused to provide Mr. Seelye with a copy of my firm's proprietary software to conduct SPR analyses, even though Mr. Seelye had developed his own SPR software.

In this case, I have restudied those three accounts using the GMT method. My exhibits relating to those accounts include spreadsheets constituting the entire GMT software I used. I have no objections to providing Mr. Seelye with that software. My results are discussed in the individual accounts discussion below.

Q. Did you use your firm's SPR software in this case for any reason, even to verify your GMT results?

A. No.

Q. Did Mr. Seelye use any industry statistics to support his judgmental depreciation rates?

A. Mr. Seelye states that his selected depreciation rates are "reasonable compared with other gas distribution utilities in the area."[9] AG Data Request Nos. 1-102 and 1-103 requested

[9] Seelye Exhibit 11, individual account discussions.

any industry statistics available to Mr. Seelye and the industry statistics he used in formulating his depreciation proposals. The response to those requests referred to PSC Data Request No. 2-48. In response to PSC 2-48 Mr. Seelye provided the lives and survivor curves for three companies. He did not provide any depreciation rates.

Q. Why is it significant that Mr. Seelye did not provide the industry depreciation rates upon which he based his judgment?

A. Depreciation rates are a function of the chosen life, dispersion curve and net salvage value. In the case of remaining life depreciation rates, the remaining life must be calculated for the plant in question. Even if two companies select the same life and curve, the resulting remaining lives will be different due to the different mix of plant placements. Mr. Seelye claims his <u>rates</u> are comparable, but he failed to provide the standard to which he compared them, assuming he made such a comparison.

Q. Describe your disagreements with Mr. Seelye's depreciation rate proposals.

A. I will discuss each account where I recommend a change:

<u>Account 351 – Storage Structures and Improvements</u>

Mr. Seelye proposes a 32-year remaining life for most of the accounts in the Storage function. Mr. Seelye asserts this is "the remaining life approved by the Commission in Delta's last rate case."[10] It appears Mr. Seelye may have made a mistake for account 351. In Case No. 2004-00067, Mr. Seelye proposed a 36-year remaining life for accounts 352 through 356, a 40-year remaining life for account 351, and a 30-year life

[10] See response to AG 1-160.

for account 357.[11] In the current case, Mr. Seelye subtracted 4 years from those remaining lives except for account 351. Mr. Seelye subtracted 8 years from the 40-year remaining life for account 351. Since I did not challenge these lives in Case No. 2004-00067, I have accepted Mr. Seelye's premise that the remaining lives in this case should be four years less than the previous case. Consequently, I have corrected the 32-year remaining life for account 351, and increased it to 36 years. This correction decreases the depreciation rate from 2.48% to 2.20%.

<u>Account 353 – Storage Lines</u>

Although I have accepted Mr. Seelye's 32-year remaining life for this account, I cannot recreate his 2.44% depreciation rate. The correctly calculated rate for this account using a 32-year remaining life is 2.05%.

<u>Account 356 – Purification Equipment</u>

Mr. Seelye calculated a 2.02% rate for this account using a plant balance of $360,432 and a 32-year remaining life. However, according to Delta's Schedule 4, provided in response to PSC Data Request 2-6, the correct plant balance is $326,326. Using this balance, the calculated depreciation rate should be 1.91%.

<u>Account 369 - Measuring and Regulator Station Equipment - Transmission</u>

Mr. Seelye proposed a rate of 3.14% for this account, based on his analysis. A non-legal cost of removal reserve existed for this account, which when added back, reduces the rate to 3.04%. However, this is one of the accounts I challenged in Case No. 2004-00067. Consequently, I more closely scrutinized Mr. Seelye's proposal. He states that

[11] See Case No. 2004-00067, Response to Hearing Data Request of the Commission Staff Dated August 18, 2004, Question No. 10.

his SPR analysis revealed that "no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S3 curve with an average service life of 39 years provided excellent results for all four metrics."[12] I investigated this statement, and discovered that it is not correct. Mr. Seelye's SPR in this case provides what appear to be meaningless results and none of the results is a 39 year life with an S3 curve. In fact, Mr. Seelye's words are the same words he used four years ago. His current study does not support his position.

I conducted a GMT analysis which is attached as Exhibit___(MJM-5), page 2 of 12. It indicates a 48-year average service life for the full band of available data. The rolling three-year band results are also attached. I recommend a 48-year average service life for this account. I have calculated the 37-year corresponding remaining life by subtracting the 11-year weighted average age from the average service life. This results in a 2.22% remaining life depreciation rate.

<u>Account 376 – Mains – Distribution</u>

This is another of the accounts I challenged in Case No. 2004-00067. In that case, Mr. Seelye stated that, "the R3 curve with an ASL of 37 years provided solid results for all four metrics."[13] Mr. Seelye says the exact same thing in this case.[14] His SPR, however, bears no relationship to that statement.

I conducted a GMT analysis which is attached as Exhibit___(MJM-5), pages 5 and 6 of 12. It indicates a 62-year average service life for the full band of available data. I have also attached the rolling three-year band results as page 8. I recommend a 62-year

[12] Seelye Depreciation Study – Exhibit 11, p. 6.
[13] Seelye Exhibit 7, Case No. 2004-00067.
[14] Seelye Depreciation Study – Exhibit 11, p. 2.

average service life for this account. I have calculated the 46-year corresponding remaining life by subtracting the 16-year weighted average age from the average service life. This results in a 1.41 percent remaining life depreciation rate.

<u>Account 380 – Distribution Services</u>

As explained above, the add-back of Delta's cost of removal regulatory liability has a major impact on a calculated remaining life depreciation rate for this account. Mr. Seelye, however, did not calculate a depreciation rate for Services. Instead, he used his overstated depreciation rate for account 376 – Distribution Mains. Following Mr. Seelye's logic, I have used the correct 1.41 percent Distribution Mains depreciation rate for Distribution Services.

<u>Account 378 – Measuring and Regulator Station Equipment – Distribution</u>

Mr. Seelye proposes a 3.27% depreciation rate for this account. The account has a small amount of negative cost of removal reserve associated with it. When this reserve is added to the depreciation reserve, the rate increases to 3.28%.

<u>Account 379 - Measuring and Regulator Station Equipment – City Gate</u>

Mr. Seelye proposes a 3.19% rate for this account. A non-legal cost of removal reserve existed for this account, which when added back, reduces the rate to 3.01%.

<u>Account 382 -- Meter and Regulator Installations</u>

Mr. Seelye proposes a 4.50% depreciation rate for this account based on his analysis. A non-legal cost of removal reserve existed for this account, which when added back, reduces the rate to 4.08%.

Mr. Seelye proposes a 54-year average service life for this account even though it bears no relationship to his SPR analysis results. I challenged Mr. Seelye's proposal for this account in Case No. 2004-00067 for the same reason.

In this case, I conducted a GMT analysis which is attached as Exhibit___(MJM-5), page 10 of 12. It indicates a 60-year average service life for the full band of available data. I have also attached the rolling three-year band results. I recommend a 60-year average service life for this account. I have calculated the 46-year corresponding remaining life by subtracting the 14-year weighted average age from the average service life. This results in a 2.33 percent remaining life depreciation rate.

Account 383 – House Regulators

Mr. Seelye's discussion of this account is confusing. He reports the balance as being $1,917,622, which is neither the gross plant balance, nor the amount to be recovered. He also hard-coded the 4.13% rate into the file, instead of calculating a rate based on his proposed remaining life. Because his discussion gives no indication that he did not intend to use his proposed remaining life, I have calculated the depreciation rate using that life. The rate changes from Mr. Seelye's proposed 4.13% to 3.80%.

Account 385 – Industrial Measuring and Regulator Station Equipment – Distribution

Mr. Seelye proposed a rate of 2.40% for this account, based on his analysis. A non-legal cost of removal reserve existed for this account, which when added back, reduces the rate to 2.31%.

Q. What is the result of your depreciation rate changes?

A. My depreciation rate changes decrease the Company's depreciation adjustment by $933,625.[15]

CWIP Depreciation Expense

Q. What adjustment did you make to Delta's proposed depreciation expense on construction work in progress ("CWIP")?

A. Delta included $38,793 amount in depreciation expense associated with CWIP in its depreciation expense claim. I do not believe that CWIP should ever be depreciated. Depreciation expense should be matched to the service of the plant, and CWIP is not plant in service. For this reason, I have removed the entire amount.

Q. How did the Commission treat depreciation associated with CWIP in the last case?

A. In Case No. 2004-00067 the Commission disallowed depreciation expense associated with CWIP, for much the same reason I have removed it here.

> CWIP represents the total of the balances of work orders for gas plant under construction. As such, this gas plant is not available for or providing service to customers. Depreciation, as defined in the Uniform System of Accounts, means the loss in service value not restored by current maintenance, which is incurred in connection with the consumption or prospective retirement of the gas plant. Consequently, the Commission generally does not calculate depreciation expense on CWIP. In the event a utility proposed to recognize new plant additions occurring after test-year end, it might be appropriate to recognize a level of depreciation expense on the new plant additions. However, in this case, Delta did not propose the recognition of any new plant additions occurring after test-year end. Accordingly, the Commission finds that depreciation expense on CWIP should not be included for rate-making purposes.[16]

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[15] Company depreciation expense for account 101 of $4,781,712 (see Schedule 4 provided in response to PSC 2-6) less AG depreciation expense for account 101 of $3,848,087 (see Exhibit___(MJM-4), Schedule 1, page 3).

[16] Case No. 2004-00067, Order issued November 10, 2004, p. 31 (footnotes removed).

Q. Did Delta propose any pro forma adjustments for plant additions in this case?

A. No.[17]

Q. What is the total impact of your depreciation expense adjustments?

A. My adjustments, including both rate changes and the disallowance of CWIP reduce depreciation expense by $972,418. As mentioned above, I have made a corresponding adjustment to accumulated depreciation, however I have limited my adjustment to a reversal of Delta's rate base reduction.[18]

<u>**Adjustment No. 4 – Customer Growth**</u>

Q. What is a customer growth adjustment?

A. A customer growth adjustment is a normalization adjustment intended to match the numbers of customers in the test-year with the anticipated number of customers expected on a going-forward basis. By its very nature, a customer growth adjustment anticipates that the average number of customers is expected to grow, thus yielding more revenues for revenue requirement purposes than are recorded on the books in the test-year. In other words, customer growth adjustments typically reduce revenue requirements.

Q. Did the Commission adopt a customer growth adjustment in Case No. 2004-00067?

A. Yes, the Commission "found that a customer growth adjustment is appropriate and should be based on information in the record."[19]

Q. Do you agree with customer growth adjustments?

A. Yes, I do agree with customer growth adjustments if they are appropriate.

Q. Did Delta calculate a customer growth adjustment in its filing in this case?

[17] Response to PSC 3-4a.
[18] See Exhibit___(MJM-3), Schedule 2, Adjustment No. 1.
[19] Case No. 2004-00067 Order, p. 11.

A. Yes, Mr. Seelye calculates "The standard year-end adjustment … in Seelye Exhibit 10."

Q. Did Delta include Mr. Seelye's customer growth adjustment in the quantification of its revenue requirement?

A. No, notwithstanding the fact that Mr. Seelye's standard adjustment would reduce revenue requirements, Delta did not include it in its quantification. Instead, Delta implored the Commission not to make the adjustment. Its most important rationale for not making the adjustment is reflected in Mr. Seelye's text Table 3 showing a decline in Delta's average customers per year. Unfortunately, Mr. Seelye provided figures in data responses that did not match his text table numbers as shown below.

Comparison of Seelye Table 3
Staff Data Requests 1-44 and 1-47
Average Customers per Year

Year	**Table 3**	**DR Responses**	**Difference**
2002	40,185	39,055	1,130
2003	39,765	39,052	713
2004	39,358	38,734	624
2005	38,981	38,351	630
2006	38,117	37,334	783

Q. What is your opinion based on this comparison?

A. In my opinion, Mr. Seelye's figures are in doubt.

Q. What do you recommend?

A. If Delta is losing customers and if it is reasonable to conclude it will continue to lose customers, then I do not recommend a customer growth adjustment. However, Mr. Seelye's figures are in doubt, and I have discovered major discrepancies in his figures elsewhere in the Company's filing. In the depreciation area for example, some of Mr. Seelye's discrepancies are startling at best. Hence, I am including the customer growth adjustment with full recognition that if Delta is losing customers and the Commission expects it to continue losing customers, the adjustment should not be made.

Adjustment No. 5 - Directors' Fees – Account 930.01

Q. What is the purpose of Adjustment No. 5?

A. Adjustment No. 5 removes $68,264 from Account 930.01 – Directors Fees and Expenses.

Q. Please explain the adjustment.

A. I have removed $26,400 in retainer and committee service fees for Harrison Peet and Jane Green. I have also removed the entire amount of the cash bonus paid to directors, which is $40,300. Finally, I have removed $1,564 in miscellaneous expenses.

Q. Why have you removed fees related to Mr. Peet and Ms. Green?

A. Delta made adjustments to its directors' compensation and reduced the number of directors in 2006 based on a study of directors' compensation performed by Mercer Human Resource Consultants.[20] The number of directors was reduced from 10 to 8, based on a new "age" policy. This new policy resulted in Harrison Peet and Jane Green not standing for reelection. As these individuals are no longer on the board, and Delta does not intend to replace them, their compensation should be removed from the cost of service.

Q. Why have you removed the cash bonus?

[20] Jennings Direct Testimony, p. 15.

A. In Case No. 2004-00067 the Commission excluded the bonus paid to directors from ratemaking, noting that the Company had not adequately explained why the bonus was necessary. One purpose of a company's board of directors is to maximize shareholder wealth. This does not necessarily contribute to the provision of safe, reliable gas service, and in some cases, can run counter to the goal of minimizing ratepayer expense. Therefore, I believe the shareholders should shoulder some responsibility for the directors' compensation.

Q. What is the $1,564 in miscellaneous expenses related to?

A. I do not know. The directors' compensation for 2006 is outlined in response to PSC 2-58a. The $1,564 is the difference between the amount shown in that response for account 193.01 and the amount shown in response to PSC 1-27b. It is made up of several small charges. Possibly it represents expenditures for gifts or social events. Regardless, as it is not directors' compensation, I have removed it.

<u>Adjustment No. 6 – Normalized Pension Expense</u>

Q. What is the purpose of Adjustment No. 6?

A. Adjustment No. 6 normalizes Delta's pension expense in accordance with its response to PSC 2-19. Delta states "If we are going to base an adjustment on historical experience, we would average the 3/31/07 expected expense of $567,300 based on the report attached in (b) above [most current actuarial analysis] with the three preceding years to compute normal pension expense to be $639,919, a $60,343 reduction in test year expense."

<u>Adjustment No. 7 - Consultant Fees – Account 923</u>

Q. What is the purpose of Adjustment No. 7?

A. Adjustment No. 7 removes $51,040 in expenses related to consultant fees paid to retired employees during the test year.

Q. Please explain the adjustment.

A. Delta's test year cost of service includes consultant fees paid to several retired employees. These employees include Harrison Peet, the retired Chairman of the Board, President and CEO, Eunice Yarber, a retired accounting department employee, Juanita Hensley, a retired HR employee and Marjorie Sidwell, a retired administrative support employee.[21] I have removed the expenses related to these individuals from Account 923 – Professional Services.

Q. Why have you removed the consulting expenses related to Mr. Peet?

A. Mr. Peet provides "general consulting services to Delta's Chairman, President and CEO."[22] He was paid $2,000 per month for each month during 2006 for these services.[23] As he is the retired Chairman of the Board, President and CEO, I feel that any consulting services he provides are more likely related to maximizing shareholder wealth, rather than the provision of safe, reliable gas service. Therefore, I have removed $24,000 in consulting fees paid to Mr. Peet.

Q. Why have you removed the consulting fees paid to the other three retired employees?

A. Ms. Yarber, Ms. Hensley and Ms. Sidwell provided consulting services to their previous departments during the year. Ms. Yarber was paid $700 per month for each month during

[21] Response to PSC 2-61a and 3-26.
[22] Response to PSC 2-61a.
[23] Response to PSC 2-60.

2006.[24] Ms. Hensley was paid $3,000 per month for the period July through December, 2006.[25] Ms. Sidwell was paid $640 in October, 2006.[26] I do not have any information as to whether or not the positions vacated by these individuals were filled; however, I have assumed that they were. In either case, sufficient time has passed for another employee to become fully trained on the services these employees are providing. As such, I have removed $27,040 in expenses related to these consultants from Delta's cost of service.

Adjustment No. 8 - Conservation Program – Account 930.11

Q. What is the purpose of Adjustment No. 8?

A. Adjustment No. 8 removes $32,821 in expenses related to the Company's "conservation program for builders, developers and customers who installed additional gas appliances and received amounts under Delta's incentive program."[27]

Q. How did the Commission treat conservation program expense in the last case?

A. In Case No. 2004-00067, the Commission excluded the entire balance of account 930.11 for ratemaking purposes. According to the Commission, the conservation program expenses represented promotional advertising: "These materials clearly promote the selection and use of gas appliances over other appliances. Consequently, Administrative Regulation 807 KAR 5:016, Section 4 requires exclusion of the expenses for rate-making purposes."[28]

Q. Does the conservation program still promote the selection of gas appliances over appliances powered by other energy sources?

[24] Response to PSC 2-60.
[25] Id.
[26] Id.
[27] See response to PSC 2-58.
[28] Case No. 2004-00067, Order issued November 10, 20045, p. 25.

A. Yes. According to the response to PSC 3-24f, the "program provides incentives to builders and developers to install more natural gas appliances."

Q. Does the conservation program promote the selection of high efficiency gas appliances?

A. No. Delta's program sets no specific efficiency levels. Instead, the Company appears to feel the conservation is in the area of electricity usage.[29] It is clear the sole purpose of this program is to promote the use of natural gas over other energy sources.

Q. What do you recommend?

A. Because the conservation program is clearly a form of promotional advertising, I recommend disallowance of the entire $32,821 amount, consistent with the Order in the last case.

Adjustment No. 9 - Mercer Directors Compensation Study – Account 923

Q. What is the purpose of Adjustment No. 9?

A. Adjustment No. 9 removes $21,025 in expenses related to the Directors' Compensation Study conducted by Mercer Human Resource Consulting. This has the effect of allowing recovery of this expenditure as an amortization over three years.

Q. Please explain the adjustment.

A. Delta incurred $31,537 in expenses related to a study on Directors' Compensation conducted by Mercer Human Resource Consulting during the test year. This is a nonrecurring expense, which I believe would be more appropriate to recover through amortization. I have used a three-year amortization period, consistent with the period

[29] Response to PSC 3-24f.

used to amortize rate case expenses. Therefore, I have removed two thirds of the expense from the cost of service.

Q. If it is a nonrecurring expense, why are you recommending recovery?

A. I am recommending recovery of this expense because it was incurred at the Commission's direction. In Case 2004-00067 the Commission directed the Company to conduct an analysis of its directors' compensation.[30] The Mercer study is the result of that requirement. Because of the circumstances behind the study, I feel it is appropriate to allow the expense, but it should be amortized.

Q. Does Delta have an opinion concerning this adjustment?

A. In response to PSC Data Request 3-27, the Company stated that the expense could be amortized if the Commission desired.

Q. What do you recommend?

A. I recommend that the $31,537 expense related to the Mercer study be amortized over a three year period – an amount of $10,512 per year. This adjustment results in $21,025 being removed from Delta's cost of service.

<u>Adjustment Nos. 10 and 11 - Employee Gifts, Awards and Social Events – Accounts 930.08 and 926.05</u>

Q. What is the purpose of Adjustment Nos. 10 and 11?

A. Adjustment No. 10 removes $7,680, the entire balance of account 926.08 – Employee Recreation and Social, and Adjustment No. 11 removes $5,081 in expenses from account 930.05 – Company Relations, from the Company's cost of service calculation.

Q. How did the Commission treat these expenses in the last case?

[30] Case No. 2004-00067, Order Issued November 10, 2004, p. 37.

A. In Case No. 2004-00067, the Commission excluded expenses related to employee gifts, awards and social events, stating "We are of the opinion that Delta's shareholders have some responsibility for maintaining good employee morale, employee retention, and good community relations."[31] The Commission permitted expenses related to employee service and safety awards.

Q. What types of expense items are included in account 926.08?

A. Account 926.08, Employee Recreation and Social, includes expenses related to employee potlucks, Christmas luncheons and other meetings. These are the types of expense the Commission removed in the last case.

Q. Have you removed the entire amount of account 930.05?

A. No. I have allowed expense items related to service and safety awards. I have also allowed expenses related to Delta T-shirts provided to employees. In response to PSC 3-244d, the Company explained that these shirts are intended to visually identify Delta employees to customers. I have also allowed expenses related to the Company newsletter, Delta Digest.

Q. What expense items have you removed?

A I have removed all expenses related to the provision of flowers, thermometers and retirement events. According to the Company, the purpose of these expenses is to improve employee relations and morale.[32] Per the Commission's order in Case No. 2004-00067, these types of expenses should be excluded for rate-making purposes.

Q. What do you recommend?

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[31] Case No. 2004-00067, Order issued November 10, 20045, p. 46.
[32] Response to PSC 3-24d.

A. Based on the Commission's Order in Case No. 2004-00067, and my analysis of these accounts, I have removed $7,680 from account 926.08 and $5,081 from account 930.05 from the Company's cost of service.

Adjustment No. 12 – Normalize 401K expense

Q. What is the purpose of Adjustment No. 12?

A. In conjunction with Adjustment No. 6, Adjustment No. 12 normalizes 401K expense in accordance with Delta's response to PSC 2-19. It increases test year expense by $2,890.

Adjustment No. 13 - Customer and Public Information – Account 930.09

Q. What is the purpose of Adjustment No. 13?

A. Adjustment No. 13 removes $2,606 in expenses related to promotional advertising from the Company's expense for customer and public information.

Q. Are you removing the entire amount of account 930.09?

A. No. I am only removing the amount that is obviously related to promotional advertising. I have left $27,887 of expense in the cost of service, as it does not appear to relate to promotional advertising.

Q. How did the Commission treat this expense in the last case?

A. In Case No. 2004-00067, the AG challenged $4,914 in expenses recorded in account 930.09, as being promotional expenses.[33] The Commission reviewed the specific expense items and determined that $3,432 was indeed related to promotional items.[34]

Q. Did you review the specific expense items that make up the $30,493 balance in this account?

[33] Case No. 2004-00067, Order issued November 10, 20045, p. 44.
[34] Case No. 2004-00067, Order issued November 10, 20045, p. 45.

A. Yes. Delta's response to PSC 2-58 provided the transaction details for this account. Additional information was provided in response to PSC 3-24. Based on these data responses, I have removed expenses related to three items: a Christmas Greeting, Pocket Pals provided to industrial customers, and calendars provided to customers. These items are clearly promotional and should be excluded for rate-making purposes.

Q. What do you recommend?

A. The items listed above are clearly promotional and should be excluded for rate-making purposes. Therefore, I have removed $2,606 related to these expenditures from the Company's cost of service.

Adjustment No. 14 - Athletic Events and Tickets

Q. What is the purpose of Adjustment No. 14?

A. Adjustment No. 14 removes $1,036 in expenses related to athletic events and other sporting event tickets.

Q. Please explain the adjustment.

A. AG Data Request 1-227 asked for all expenses during the test year for athletic events, tickets, sky boxes and other sporting activities. Delta had two such expenses – one for Keeneland Guest Tickets and another for University of Kentucky football tickets. Neither of these expenses is necessary for the provision of safe, reliable gas service; therefore, I have removed them from the Company's cost of service.

Q. Do you know to which account these expenses were charged?

A. No. Delta did not provide that information. However, a review of the expenditures in Account 930 - Miscellaneous General Expenses did not show these charges. As such, I do not believe I have already removed them.

<u>Adjustment No. 15 - Company Memberships – Account No. 930.02</u>

Q. What is the purpose of Adjustment No. 15?

A. Adjustment No. 15 removes $840 from Account No. 930.02 – Company Memberships.

Q. Which memberships are you removing and why?

A. I have removed the expenses related to Delta's membership in the Society of Corporate Secretaries and the American Institute of Public Accountants ("AICPA") membership for Glenn Jennings. Delta's involvement in the Society of Corporate Secretaries is related to its need to file reports with the Securities and Exchange Commission ("SEC").[35] SEC reports are for the benefit of shareholders; therefore, this expense should be borne by them. The expense related to Mr. Jenning's membership in the AICPA is also more related to Delta's status as a publicly owned company, rather than the provision of gas service. Mr. Jenning's AICPA membership did not provide any value to ratepayers. Ratepayers should not foot the bill for his AICPA membership.

<u>Adjustment No. 16 - Country Club Memberships – Account 921.07</u>

Q. What is the purpose of Adjustment No. 16?

A. Adjustment No. 16 removes $640 related to country club fees from Account No. 921.07 – Employee Memberships.

Q. Please explain the adjustment.

[35] Response to PSC 2-58b.

A. AG Data Request 1-245 asked for all expenses during the test year for country club fees. During the test year Delta incurred $640 in fees related to Glenn Jennings' membership in the Lexington Club. This expense is not necessary for the provision of safe, reliable gas service; therefore, I have removed it from the Company's cost of service.

<u>Adjustment No. 17 - AGA Dues Related to Lobbying – Account 930.02</u>

Q. What is the purpose of Adjustment No. 17?

A. Adjustment No. 17 removes $588 from the dues paid to the American Gas Association ("AGA") in 2006. This amount is presumed to be related to lobbying activities.

Q. How did the Commission treat AGA dues in the last case?

A. In Case No. 2004-00067 the Commission determined that 2 percent of the Company's AGA dues should be excluded as being related to lobbying activities.[36]

Q. Has Delta made any adjustments to the level of AGA dues it is including in its revenue requirement claim?

A. No. The response to AG Data Request 1-248 indicates that the total AGA annual dues were included in test year expense.

Q. What do you recommend?

A. I recommend excluding 2 percent of the Company's AGA dues, consistent with the Commission's Order in the last case. This amount is $588.

<u>Adjustment No. 18 - Interest Synchronization</u>

Q. Please explain your adjustment No. 18.

A. My adjustment No. 18 synchronizes the interest expense resulting from my recommended

[36] Case No. 2004-00067, Order issued November 10, 2004, p. 43.

rate base and Dr. Wooldridge's capital structure and cost of capital, with the tax allowance calculation.

Summary

Q. Please summarize your testimony and recommendations

A. Delta proposed a $5.6 million increase. I have adjusted or eliminated several of expense overstatements. The adjustments, combined with Dr. Woolridge's cost of capital result in an AG proposal of a $3.4 million revenue increase. This is a reasonable amount. Further, I note that the lack of discussion in my testimony of any other aspects of the Company's request does not constitute an endorsement of such aspects.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit___(MJM-1)

Summary Schedules

Index

DELTA NATURAL GAS CO.
CASE NO: 2007-00089
COMPARATIVE OVERALL FINANCIAL SUMMARY
FOR THE TEST YEAR ENDED DECEMBER 31, 2006

Line		Company Amount 1/ (a)	AG Amount (b)	Difference (c)=(b)-(a)
1	Cost of gas	$ 35,207,784	$ 35,207,784	$ -
2	Operations & maintenance expense	11,613,160	11,364,087	(249,073)
3	Depreciation expense	4,527,705	3,555,287	(972,418)
4	Taxes other than income taxes	1,796,243	1,796,243	-
5	Return	10,423,457	8,997,949 2/	(1,425,508)
6	Income tax	3,043,196	3,636,945	593,749
7	Total revenue requirements	$ 66,611,545	$ 64,558,295	$ (2,053,250)
8	Revenues at present rates	(60,970,869)	(61,140,977)	170,108
9	Revenue deficiency	$ 5,640,676	$ 3,417,318	$ (2,223,358)
10	Percent increase	9.25%	5.59%	

1/ See PSC 2-6, Item 6 d(2), Schedule 1.
2/ Exhibit___(MJM-3), Schedule 1.

Delta Natural Gas Co., Inc.

Summary of Attorney General Adjustments

Line	Description	Company Proforma Amount		AG Adj. 1 Depreciation Impact on Ratebase	AG Adj. 2 Cash Working Capital	AG Adj. 3 Depreciation Expense	AG Adj. 4 Customer Growth	AG Adj. 5 Directors Fees	AG Adj. 6 Pension Expense	AG Adj. 7 Consulting Fees	AG Adj. 8 Conservation Program	AG Adj. 9 Amortize Mercer Study	AG Adj. 10 Emp. Rec. & Social	AG Adj. 11 Company Relations
1	Revenues	$ 60,970,869	1/	$ -	$ -	$ -	$ 170,108	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Less: Operating Expenses													
3	Cost of gas	35,207,784		-	-	-	-	-	-	-	-	-	-	-
4	Operations & maintenance expense	11,613,160		-	-	-	-	(68,264)	(60,343)	(51,040)	(32,821)	(21,025)	(7,680)	(5,081)
5	Depreciation expense	4,527,705		-	-	(972,418)	-	-	-	-	-	-	-	-
6	Taxes other than income taxes	1,796,243		-	-	-	-	-	-	-	-	-	-	-
7	Income tax	3,043,196				369,130	64,573	25,913	22,906	19,375	12,459	7,981	2,915	1,929
8	Total Operating Expenses	$ 56,188,088		$ -	$ -	$ (603,288)	$ 64,573	$ (42,351)	$ (37,437)	$ (31,665)	$ (20,362)	$ (13,044)	$ (4,765)	$ (3,152)
9														
10	Utility Operating Income	$ 4,782,781		$ -	$ -	$ 603,288	$ 105,535	$ 42,351	$ 37,437	$ 31,665	$ 20,362	$ 13,044	$ 4,765	$ 3,152
11														
12														
13	Rate Base	$ 117,555,384		$ 292,968	$ (31,134)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14														
15	Delta Proposed ROR	8.87%												
16														
17	AG Recommended ROR	7.64%		7.64%	7.64%									
18														
19	NOI Effect	$ (1,445,505)		$ 22,375	$ (2,378)									
20														
23	Revenue Conversion Factor	1.61631		1.61631	1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631
24														
25	Incremental Revenue Requirement	$ (2,336,381)		$ 36,164	$ (3,843)	$ (975,099)	$ (170,577)	$ (68,453)	$ (60,509)	$ (51,181)	$ (32,912)	$ (21,083)	$ (7,701)	$ (5,095)

1/ Revenues at present rates.

Delta Natural Gas Co., Inc.

Summary of Attorney General Adjustments

Line	Description	Company Proforma Amount		AG Adj. 12 401-K Expense	AG Adj. 13 Promotional Advertising	AG Adj. 14 Athletic Events	AG Adj. 15 Other Memberships	AG Adj. 16 CC Memberships	AG Adj. 17 AGA Dues	AG Adj. 18 Interest Synch.	Total AG Adjustments	AG Recommended Revenues and Expenses
1	Revenues	$ 60,970,869	1/	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 170,108	$ 61,140,977
2	Less: Operating Expenses											
3	Cost of gas	35,207,784		-	-	-	-	-	-	-	-	35,207,784
4	Operations & maintenance expense	11,613,160		2,890	(2,606)	(1,036)	(840)	(640)	(588)		(249,073)	11,364,087
5	Depreciation expense	4,527,705		-	-	-	-	-	-	-	(972,418)	3,555,287
6	Taxes other than income taxes	1,796,243		-	-	-	-	-	-	-	-	1,796,243
7	Income tax	3,043,196		(1,097)	989	393	319	243	223	65,498	593,749	3,636,945
8	Total Operating Expenses	$ 56,188,088		$ 1,793	$ (1,617)	$ (643)	$ (521)	$ (397)	$ (365)	$ 65,498	$ (627,742)	$ 55,560,346
9												
10	Utility Operating Income	$ 4,782,781		$ (1,793)	$ 1,617	$ 643	$ 521	$ 397	$ 365	$ (65,498)	$ 797,850	$ 5,580,631
11												
12												
13	Rate Base	$ 117,555,384		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 261,834	$ 117,817,218
14												
15	Delta Proposed ROR	8.87%										
16												
17	AG Recommended ROR	7.64%										
18												
19	NOI Effect	$ (1,445,505)										
20												
23	Revenue Conversion Factor	1.61631		-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631	-1.61631		
24												
25	Incremental Revenue Requirement	$ (2,336,381)		$ 2,898	$ (2,613)	$ (1,039)	$ (842)	$ (642)	$ (589)	$ 105,865	(3,593,630)	

1/ Revenues at present rates.

Delta Natural Gas Company, Inc.
Cost of Capital and Fair Rate of Return
Rate of Return Applicable to Original Cost Rate Base
For the Test Year Ending December 31, 2006

Capital Source	Capitalization Amount	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short/Current Long-Term Debt	$ 17,146,346	13.43%	6.49%	0.87%
Long-Term Debt	$ 59,870,000	46.90%	6.81%	3.20%
Common Equity	$ 50,633,040	39.67%	9.00%	3.57%
Total	$ 127,649,386	100.00%		7.64%

* See Exhibit JRW-3 for capitalization ratios.

Source: Exhibit JRW-1

Exhibit___(MJM-3)

Rate Base

Index

Schedule	AG Adjustment No.	Description
Schedule 1		Rate Base Summary
Schedule 2	1	Adjustment to Accumulated Depreciation
Schedule 3	2	Adjustment to Cash Working Capital

Delta Natural Gas Co., Inc.

Summary of Rate Base
Test Year Ending December 31, 2006

Line			Company Amount	AG Adjustment	AG Amount
1	Total utility plant in service per books		$ 182,191,296	$ -	$ 182,191,296
2	Add:	Materials and supplies (13 mo avg)	434,879	-	434,879
3		Prepayments (13 mo avg)	1,609,440	-	1,609,440
4		Less: KPSC prepaid	(47,440)	-	(47,440)
5		Gas in storage (13 mo avg)	9,879,627	-	9,879,627
6		Unamortized debt expense per books	5,704,177	-	5,704,177
7		Cash working capital allowance (1/8 O&M)	1,451,645	(31,134)	1,420,511
8		Subtotal	$ 19,032,328	$ (31,134)	$ 19,001,194
9	Deduct:	Accumulated depreciation per books	$ (61,275,499)	$ -	$ (61,275,499)
10		Depreciation adjustment (Schedule 4)	(292,968)	292,968	-
11		Cost of removal	(831,877)	-	(831,877)
12		Customer advance for construction	(51,708)	-	(51,708)
13		Accumulated deferred income taxes	(21,216,188)	-	(21,216,188)
14		Subtotal	$ (83,668,240)	$ 292,968	$ (83,375,272)
15	Rate base		$ 117,555,384	$ 261,834	$ 117,817,218
16	Weighted cost of capital		8.867%		7.637%
17	Return		10,423,457		8,997,949

Delta Natural Gas Co., Inc.

AG Adjustment No. 1

Accumulated Depreciation

Line	Description	Amount
1	Delta's depreciation expense adjustment to accumulated depreciation	(292,968) 1/
2	AG reversal of Delta Adjustment	292,968
3	Increase to rate base	292,968

Sources:
1/ See PSC 2-6, Schedule 4.

Delta Natural Gas Co., Inc.

AG Adjustment No. 2

Cash Working Capital

Line	Description		Amount	
1	Total AG adjustments to O&M	$	(249,073)	1/
2	Cash working capital allowance adjustment (1/8 O&M)		(31,134)	2/
3	Adjustment - Pre Tax	$	(31,134)	

Sources:
1/ Exhibit___(MJM-1), Schedule 2.
2/ Company uses 1/8 O&M to calculate its cash working capital allowance. See PSC 2-6, Schedule 6.

Exhibit___(MJM-4)

Operating Income Adjustments

Index

Schedule	AG Adjustment No.	Description
Schedule 1	3	Adjustment to Depreciation Expense
Schedule 2	4	Adjustment for Customer Growth
Schedule 3	5	Adjustment to Directors' Fees
Schedule 4	6	Adjustment to Pension Expense
Schedule 5	7	Adjustment to Consulting Fees
Schedule 6	8	Adjustment to Conservation Program
Schedule 7	9	Adjustment to Amortize Mercer Study
Schedule 8	10	Adjustment to Employee Recreation and Social
Schedule 9	11	Adjustment to Company Relations
Schedule 10	12	Adjustment to 401-K Expense
Schedule 11	13	Adjustment to Promotional Advertising
Schedule 12	14	Adjustment to Athletic Events
Schedule 13	15	Adjustment to Other Memberships
Schedule 14	16	Adjustment to Country Club Memberships
Schedule 15	17	Adjustment to AGA Dues
Schedule 16	18	Adjustment for Interest Synchronization

Delta Natural Gas Co., Inc.

AG Adjustment No. 3

Depreciation Expense

Line	Description	Amount	
1	Delta's pro forma depreciation expense	$ 4,527,705	1/
2	AG's pro forma depreciation expense	3,555,287	2/
3	Difference	972,418	
4	Adjustment - Pre Tax	$ (972,418)	
5	Tax Rate	37.96%	
6	Tax Effect (L. 4 * L. 5)	369,130	
7	Adjustment - Post Tax (L. 4 + L. 6)	$ (603,288)	
8	Revenue Conversion Factor	1.61631	
9	Revenue Requirement (L. 7 * L. 8)	$ (975,099)	

Sources:
1/ See PSC 2-6, Schedule 4.
2/ See page 4.

Delta Natural Gas Co.
Calculation of Depreciation Expense
Based on AG Recommended Depreciation Rates

LINE NUMBER	ACCT NO	DESCRIPTION	PLANT 12/31/2006	AG DEPR RATE	DEPR EXPENSE	
1	301	Organization	53,151	0.00%	0	
2	302	Franchise & Consent	-	0.00%	0	
3		Sub Total	53,151		0	
		PRODUCTION				
4	304	Land & Rights		0.00%	0	
5	305	Structures & Improvements		2.20%	0	
6	325	Right of Ways	75,987	3.00%	2,280	
7	327	Comp Stations Structures	42,950	3.00%	1,289	
8	331	Well Equipment	7,795	4.00%	0	
9	332	Field Lines	1,914,741	2.25%	43,082	
10	333	Compressor Station Equipment	817,962	4.00%	32,718	
11	334	Measuring & Regulator Stations	136,937	2.72%	3,725	
12		Sub Total	2,996,372		83,094	
		STORAGE & PROCESSING				
13	35001	Storage Land	14,142	0.00%	0	
14	35002	Storage Right of Way	177,425	0.00%	0	
15	35005	Gas Rights Well	1,495	0.00%	0	
16	35006	Gas Rights Storage		5.00%	0	
17	351	Structures and Improvements	294,116	2.20%	6,471	1/
18	352	Storage Wells	360,583	2.19%	7,897	
19	35201	Storage Rights	860,396	1.85%	15,917	
20	35202	Storage Reservoirs	1,881,731	1.78%	33,495	
21	35203	Non-Recoverable Natural Gas	294,307	1.75%	5,150	
22	353	Storage Lines	5,091,297	2.05%	104,372	1/
23	354	Storage Compressor Station Equipment	2,419,643	1.90%	45,973	
24	355	Storage Measuring & Regulator Equipment	363,662	2.41%	8,764	
25	356	Purification Equipment	326,326	1.91%	6,233	1/
26	357	Storage Other Equipment	47,209	0.53%	250	
27		Sub Total	12,132,332		234,522	
		TRANSMISSION				
28	3651	Land and Rights	56,999	0.00%	0	
29	3652	Rights of Way	1,212,507	0.00%	0	
30	3653	Land Rights CVPL	163,626	2.50%	4,091	
31	366	Structures and Improvements	182,239	2.00%	3,645	
32	367	Transmission Mains	41,447,022	2.24%	928,413	
33	368	Compressor Station Equipment	2,463,406	2.00%	49,268	
34	369	Measuring & Regulator Station Equipment	2,665,648	2.22%	59,177	1/
35	371	Other Equipment	579,896	2.00%	11,598	
36		Sub Total	48,771,343		1,056,192	

Delta Natural Gas Co.
Calculation of Depreciation Expense
Based on AG Recommended Depreciation Rates

LINE NUMBER	ACCT NO	DESCRIPTION	PLANT 12/31/2006	AG DEPR RATE	DEPR EXPENSE	
		DISTRIBUTION				
1	374	Distribution Rights of Way	258,985	0.00%	0	
2	37401	Distribution Land	63,206	0.00%	0	
3	375	Structures & Improvements	113,715	2.67%	3,036	
4	376	Distribution Mains	61,423,134	1.41%	866,066	1/
5	378	Measuring & Regulator Station - General	1,356,370	3.28%	44,489	1/
6	379	Measuring & Regulator Station - City Gate	480,352	3.01%	14,459	1/
7	380	Services	12,658,475	1.41%	178,484	1/
8	381	Meters	8,917,576	2.28%	203,321	
9	382	Meter and Regulator Installation	3,145,615	2.33%	73,293	1/
10	383	House Regulators	3,093,300	3.80%	117,545	1/
11	385	Industrial Meter Sets	1,530,217	2.31%	35,348	1/
12		Sub Total	93,040,945		1,536,041	
		GENERAL				
13	389	Land and Rights	1,038,741	0.00%	0	
14	390	Structures and Improvements	5,452,189	2.00%	109,044	
15	391	Office Furniture and Equipment	135,672	1.00%	1,357	
16	392	Autos and Trucks	3,868,757	8.14%	314,917	
17	393	Stores Equipment	36,011	2.00%	720	
18	394	Tools and Work Equipment	629,382	4.00%	25,175	
19	39401	Comp NG Stat and Equipment	283,352	0.00%	0	
20	395	Laboratory Equipment	215,820	5.00%	10,791	
21	396	Power Operated Equipment	2,779,542	2.00%	55,591	
22	397	Communication Equipment	443,788	5.00%	22,189	
23	398	Miscellaneous Equipment	54,238	2.00%	1,085	
24	3991	Other Tangible Equipment	638,509	4.00%	25,540	
25	3992	Computer Software	2,525,991	10.00%	252,599	
26	3993	Computer Hardware	937,029	10.00%	93,703	
27	399031	Computerized Office Equipment	255,272	10.00%	25,527	
28		Sub Total	19,294,293		938,238	
29		TOTAL A/C 101	176,288,436		3,848,087	
		CWIP				
30	368	525528	1,480,882	0.00%	-	
31	369		175,071	0.00%	-	
32	371	525506	3,463	0.00%	-	
33	376		112,282	0.00%	-	
34	381	255529	7,843	0.00%	-	
35	392	530025	525	0.00%	-	
36	39902	63002	5,800	0.00%	-	
37	Overhead	53010	489,686			
38		Total CWIP	2,275,552		-	
		ACQUISITION ADJUSTMENT				
1	1.114	Tranex	(1,045,704)		(58,800)	
2	1.114.01	Mt. Olivet	464,945		46,800	
3		Total Acquisition Adjustment	(580,759)		(12,000)	

Delta Natural Gas Co.
Calculation of Depreciation Expense
Based on AG Recommended Depreciation Rates

LINE NUMBER	ACCT NO	DESCRIPTION	PLANT 12/31/2006	AG DEPR RATE	DEPR EXPENSE
4	1.117	Gas Stored Underground	4,208,069		
5					
6	Total Utility Plant In Service		182,191,298		3,836,087
		ASSET RETIREMENT OBLIGATION			
7	1.376.01	Distribution Mains	210,849		
8	1.380.01	Distribution Services	138,932		
9		Excluded from plant accounts above	74,634		
10	Reconciled Total		182,615,713		
11	Per Delta Balance Sheet		182,615,711		
12	Difference		2		
	TRANSPORTATION CLEARING				
13	Transportation Equipment				(242,400)
14	Power Operated Equipment				(38,400)
15	Pro Forma Depreciation Expense				3,555,287
16	Per Delta Income Statement				4,234,739
17	Depreciation Expense Adjustment from Book				(679,452)
18	Company's Depreciation Expense Adjustment				292,966
19	Difference (Total AG Adjustment) (L. 18 - L. 17)				972,418

AG Recommended Depreciation Rates Based on Plant [illegible]serve Balances as of December 31, 2006

Account		12/31/2006 Plant Balance	Dispersion	ASL	Estimated Salvage %	Net Salvage Amount	Total Depreciation Reserve	Balance To Be Recovered	Estimated Life Remaining	Annual Depreciation Amount	Total Accrual Rate
		(a)	(b)	(c)	(d)	(e)= (a) * (d)	(f)	(g)=(a)-(e)-(f)	(h)	(i)=(g)/(h)	(j)=(i)/(a)
											2.20%
305	Structures & Improvements - Manufactured Gas Plant	$ 75,987	O4	41	0%	$ -	$ 52,270	$ 23,717			3.00%
325	Gathering Land & Rights	42,950 1/					-				3.00%
327	Comp Station Structures	7,795	S6	25	0%	-	7,795	-			4.00%
331	Producing Gas Wells -- Well Equipment	1,914,741			0%	-	1,233,752	680,989			2.25% 2/
332	Gathering Lines	817,962 1/	R1	47	0%	-	660,875	157,087			4.00%
333	Gathering Compressor Stations	136,937	R3	31	0%	-	69,617	67,321	18.0	3,740	2.72%
334	Gathering Measuring and Regulator Station Equipment	294,116				-	60,887	233,229	36.0 3/	6,479	2.20%
351	Storage Structures and Improvements	360,583				-	108,431	252,152	32.0	7,880	2.19%
352	Storage Wells	860,396				-	351,216	509,180	32.0	15,912	1.85%
3521	Storage Rights	1,881,731				-	811,788	1,069,943	32.0	33,436	1.78%
3522	Storage Reservoirs	294,307				-	129,102	165,205	32.0	5,163	1.75%
3523	Storage Nonrec Natural Gas	5,091,297				-	1,752,198	3,339,099	32.0	104,347	2.05% 4/
353	Storage Lines	2,419,643				-	950,982	1,468,661	32.0	45,896	1.90%
354	Storage Compressor Stations	363,662				-	83,320	280,342	32.0	8,761	2.41%
355	Storage Measuring and Regulator Equipment	326,326 1/				-	127,301	199,025	32.0	6,220	1.91% 5/
356	Purification Equipment	47,209				-	40,686	6,524	26.0	251	0.53%
357	Storage Other Equipment	163,626	S3	27	0%	-	163,626	(0)	26.0	(0)	
3652	Rights of Way						-				2.50%
3653	Land Rights	182,239			0%	-	74,233	108,006			2.00% 2/
366	Structures & Improvements - Transmission	41,447,021	R3	43	0%	-	13,441,417	28,005,604	30.2	927,645	2.24%
367	Mains -- Transmission	2,463,406 1/			0%	-	1,059,244	1,404,162			2.00% 2/
368	Compressor Station Equipment -- Transmission	2,665,648 1/		48	-10%	(266,565)	743,748	2,188,465	37.0	59,148	2.22% 8/
369	Measuring and Regulator Station Equipment -- Transmission	579,896			0%	-	453,352	126,544			2.00% 2/
371	Other Equipment -- Transmission	113,715	L3	34	0%	-	63,842	49,873	16.4	3,041	2.67%
375	Structures and Improvements -- Distribution	61,423,134		62	0%	-	21,674,010	39,749,124	46.0	864,111	1.41% 8/
376	Mains -- Distribution	1,356,370	R1	36	-10%	(135,637)	307,833	1,184,174	26.6	44,484	3.28% 6/
378	Measuring and Regulator Station Equipment -- Distribution	480,352	R2	37	-10%	(48,035)	196,578	331,809	23.0	14,414	3.01% 6/
379	Measuring and Regulator Station Equipment -- City Gate	12,658,475					2,628,901	10,029,574			1.41% 9/
380	Services -- Distribution	8,917,576	S1	40	0%	-	3,050,384	5,867,192	28.9	203,017	2.28%
381	Meters	3,145,615		60	-45%	(1,415,527)	1,196,286	3,364,855	46.0	73,149	2.33% 8/
382	Meter & Regulator Installations	3,093,300	S6	28	5%	154,665	1,175,677	1,762,957	15.0	117,530	3.80% 7/
383	House Regulators	1,530,217	R1	43	-10%	(153,022)	500,401	1,182,837	33.5	35,351	2.31% 6/
385	Industrial Measuring and Regulator Station Equipment -- Distribution	5,452,189			40%	2,180,876	1,541,971	1,729,343			2.00% 2/
390	Structures and Improvements -- General Plant	135,672	L0	17	5%	6,784	94,318	34,571			1.00%
391	Office Furniture and Equipment -- General Plant	3,868,757	L3	6	30%	1,160,627	1,920,928	787,202	2.5	314,881	8.14%
392	Transportation Equipment	36,011			0%	-	26,487	9,524			2.00% 2/
393	Stores Equipment	629,382			5%	31,469	205,031	392,882			4.00% 2/
394	Tools & Equipment	283,352					258,732	24,621			0.00% 2/
39401	Comp Nat Gas Stat	215,820			0%	-	131,452	84,368			5.00% 2/
395	Laboratory Equipment	2,779,542			40%	1,111,817	1,603,045	64,681			2.00% 2/
396	Power Operated Equipment	443,788			5%	22,189	230,944	190,654			5.00% 2/
397	Communication Equipment	54,238			5%	2,712	46,607	4,919			2.00% 2/
398	Miscellaneous Equipment	638,509			0%	-	591,515	46,994			4.00% 2/
399.1	Other Tangible Property -- Mapping Costs	2,525,991			0%	-	1,728,173	797,818			10.00% 2/
399.2	Other Tangible Property -- Computer Software	255,272 1/					-				10.00% 2/
399031	Computerized Office Equipment	937,029					622,816	314,213			10.00% 2/
399033	Computer Hardware										

Sources: All from Seelye Exhibit 11, Appendix B unless noted below. Col. (f) from page 2.
1/ Changed balance to match Schedule 4 of filing.
2/ Seelye did not rely on his analysis, choosing instead to keep the current rate. Therefore I have removed ASL, dispersion and RL from the rate calculation sheet.
3/ Changed estimated RL to 36 (4 years less than the 40-year RL used in last case).
4/ Rate corrected to reflect calculation using 32-year remaining life, per Seelye's study.
5/ Rate changed when balance changed to match Schedule 4.
6/ Rate changed when COR reserve added back.
7/ Changed rate to calculation based on Seelye RL.
8/ Service life and remaining life based on Exhibit___(MJM-5).
9/ Per Seelye, rate is tied to rate for account 376.

Delta Natural Gas Co., Inc.
Accumulated Depreciation as of December 31, 2006

Account		Seeyle Depreciation Book Reserve	COR Reserve	Total Depreciation Reserve
305	Structures & Improvements - Manufactured Gas Plant			
325	Gathering Land & Rights	52,270		52,270
327	Comp Stattion Structures			-
331	Producing Gas Wells -- Well Equipment	7,795		7,795
332	Gathering Lines	1,233,752		1,233,752
333	Gathering Compressor Stations	660,875		660,875
334	Gathering Measuring and Regulator Station Equipment	69,617		69,617
351	Storage Structures and Improvements	60,887		60,887
352	Storage Wells	108,431		108,431
3521	Storage Rights	351,216		351,216
3522	Storage Resevoirs	811,788		811,788
3523	Storage Nonrec Natural Gas	129,102		129,102
353	Storage Lines	1,752,198		1,752,198
354	Storage Compressor Stations	950,982		950,982
355	Storage Measuring and Regulator Equipment	83,320		83,320
356	Purification Equipment	127,301		127,301
357	Storage Other Equipment	40,686		40,686
3652	Rights of Way	163,626		163,626
3653	Land Rights			-
366	Structures & Improvements - Transmission	74,233		74,233
367	Mains -- Transmission	13,441,417		13,441,417
368	Compressor Station Equipment -- Transmission	1,059,244		1,059,244
	Measuring and Regulator Station Equipment -- Transmission	673,139	70,609	743,748
	Other Equipment -- Transmission	453,352		453,352
375	Structures and Improvements -- Distribution	63,842		63,842
376	Mains -- Distribution	21,674,010		21,674,010
378	Measuring and Regulator Station Equipment -- Distribution	312,214	(4,381)	307,833
379	Measuring and Regulator Station Equipment -- City Gate	176,408	20,170	196,578
380	Services -- Distribution	2,272,997	355,904	2,628,901
381	Meters	3,050,384		3,050,384
382	Meter & Regulator Installations	852,245	344,041	1,196,286
383	Houes Regulators	1,175,677		1,175,677
385	Industrial Measuring and Regulator Station Equipment -- Distribution	454,866	45,535	500,401
390	Structures and Improvements -- General Plant	1,541,971		1,541,971
391	Office Furniture and Equipment -- General Plant	94,318		94,318
392	Transportation Equipment	1,920,928		1,920,928
393	Stores Equipment	26,487		26,487
394	Tools & Equipment	205,031		205,031
39401	Comp Nat Gas Stat	258,732		258,732
395	Laboratory Equipment	131,452		131,452
396	Power Operated Equipment	1,603,045		1,603,045
397	Communication Equipment	230,944		230,944
398	Miscellaneous Equipment	46,607		46,607
399.1	Other Tangible Property -- Mapping Costs	591,515		591,515
399.2	Other Tangible Property -- Computer Software	1,728,173		1,728,173
399031	Computerized Office Equipment			-
399033	Computer Hardware	622,816	-	622,816
		61,339,892	831,878	62,171,770

reserves by account from response to AG 2-13.

Delta Natural Gas Co., Inc.

AG Adjustment No. 4

Customer Growth

Line	Description	Amount	
1	Seelye customer count adjustment to revenue	$ 170,108	1/
2	Adjustment - Pre Tax	$ 170,108	
3	Tax Rate	37.96%	
4	Tax Effect (L. 2 * L. 3)	64,573	
5	Adjustment - Post Tax (L. 2 - L. 4)	$ 105,535	
6	Revenue Conversion Factor	1.61631	
7	Revenue Requirement (L. 5 * L. 6)	$ 170,577	

Sources:
1/ See PSC 2-58 and 3-24.

Delta Natural Gas Co., Inc.

AG Adjustment No. 5

Remove Portion of Directors' Fees

Line	Description	Amount	
	Specific Items to be Removed		
1	Peet retainer	$ 13,200	1/
2	Green retainer and committee fee	13,200	1/
3	Cash Bonus	40,300	1/
4	Miscellaneous expenses	1,564	2/
5	Total to be removed	$ 68,264	
6	Adjustment - Pre Tax	$ (68,264)	
7	Tax Rate	37.96%	
8	Tax Effect (L. 6 * L. 7)	25,913	
9	Adjustment - Post Tax (L. 6 + L.. 8)	$ (42,351)	
10	Revenue Conversion Factor	1.61631	
11	Revenue Requirement (L. 9 * L. 10)	$ (68,453)	

Sources:

1/ See PSC 2-58a.

2/ See PSC 1-27b, lines 46, 56, 111, 119 & 120. Amount makes up the difference between acct. 930.01 shown in PSC 2-58a and total shown in PSC 1-27b.

Delta Natural Gas Co., Inc.

AG Adjustment No. 6

Normalize Pension Expense

Line	Description	Amount
2	Adjustment - Pre Tax	$ (60,343) 1/
3	Tax Rate	37.96%
4	Tax Effect (L. 2 * L. 3)	22,906
5	Adjustment - Post Tax (L. 2 + L. 4)	$ (37,437)
6	Revenue Conversion Factor	1.61631
7	Revenue Requirement (L. 5 * L. 6)	$ (60,509)

Sources:
1/ See PSC 2-19b (3).

Delta Natural Gas Co., Inc.

AG Adjustment No. 7

Remove Consultant Fees

Line	Description	Amount	
	Specific Items to be Removed		
1	Hensley consulting fees	$ 18,000	1/
2	Peet consulting fees	24,000	1/
3	Sidwell consulting fees	640	1/
4	Yarber consulting fees	8,400	1/
5	Total to be removed	$ 51,040	
6	Adjustment - Pre Tax	$ (51,040)	
7	Tax Rate	37.96%	
8	Tax Effect (L. 6 * L. 7)	19,375	
9	Adjustment - Post Tax (L. 6 + L. 8)	$ (31,665)	
10	Revenue Conversion Factor	1.61631	
11	Revenue Requirement (L. 9 * L. 10)	$ (51,181)	

Sources:
1/ See PSC 2-60, 2-61 and 3-26.

Delta Natural Gas Co., Inc.

AG Adjustment No. 8

Remove Conservation Program Expense

Line	Description	Amount	
1	Conservation Program - Acct. 930.11	$ 32,821	1/
2	Adjustment - Pre Tax	$ (32,821)	
3	Tax Rate	37.96%	
4	Tax Effect (L. 2 * L. 3)	12,459	
5	Adjustment - Post Tax (L. 2 + L. 4)	$ (20,362)	
6	Revenue Conversion Factor	1.61631	
7	Revenue Requirement (L. 5 * L. 6)	$ (32,912)	

Sources:
1/ See PSC 2-58 and 3-24.

Delta Natural Gas Co., Inc.

AG Adjustment No. 9

Amortize Directors Compensation Study

Line	Description	Amount	
1	Mercer expenses related to study	$ 31,537	1/
2	Annual amortization using 3 year period (L. 1 / 3)	10,512	
3	Total to be removed (L. 1 - L. 2)	$ 21,025	
4	Adjustment - Pre Tax	$ (21,025)	
5	Tax Rate	37.96%	
6	Tax Effect (L. 4 * L. 5)	7,981	
7	Adjustment - Post Tax (L. 4 + L. 6)	$ (13,044)	
8	Revenue Conversion Factor	1.61631	
9	Revenue Requirement (L. 7 * L. 8)	$ (21,083)	

Sources:
1/ See PSC 2-60, 2-61 and 3-27.

Delta Natural Gas Co., Inc.

AG Adjustment No. 10

Remove Employee Recreation and Social Expense

Line	Description	Amount
1	Employee Recreation and Social Expense - Acct. 926.08	$ 7,680 1/
2	Adjustment - Pre Tax	$ (7,680)
3	Tax Rate	37.96%
4	Tax Effect (L. 2 * L. 3)	2,915
5	Adjustment - Post Tax (L. 2 + L. 4)	$ (4,765)
6	Revenue Conversion Factor	1.61631
7	Revenue Requirement (L. 5 * L. 6)	$ (7,701)

Sources:
1/ See AG 1-226.

Delta Natural Gas Co., Inc.

AG Adjustment No. 11

Remove Company Relations not related to Service or Safety Awards

Line	Description	Amount
1	Total Account 930.05	15,948
	Allowable Expenses	
2	Employee T-Shirts (uniforms)	$ 3,394
3	Safety Award Jackets	722
4	Employee Service Awards	3,734
5	Company newsletter	3,018
6	Total Allowable	$ 10,867
7	Total to be removed (L. 1 - L. 6)	5,081
8	Adjustment - Pre Tax	$ (5,081)
9	Tax Rate	37.96%
10	Tax Effect (L. 8 * L. 9)	1,929
11	Adjustment - Post Tax (L. 8 + L. 10)	$ (3,152)
12	Revenue Conversion Factor	1.61631
13	Revenue Requirement (L. 11 * L. 12)	$ (5,095)

Sources:
1/ See PSC 2-58 and 3-24.

Delta Natural Gas Co., Inc.

AG Adjustment No. 12

Normalize 401-K Expense

Line	Description	Amount	
2	Adjustment - Pre Tax	$ 2,890	1/
3	Tax Rate	37.96%	
4	Tax Effect (L. 2 * L. 3)	(1,097)	
5	Adjustment - Post Tax (L. 2 + L. 4)	$ 1,793	
6	Revenue Conversion Factor	1.61631	
7	Revenue Requirement (L. 5 * L. 6)	$ 2,898	

Sources:
1/ See PSC 2-19a (3).

Delta Natural Gas Co., Inc.

AG Adjustment No. 13

Remove Promotional Advertising From Customer and Public Information

Line	Description	Amount	
	Specific Charges to Acct. 930.09		
1	Christmas Greeting	$ 12	1/
2	Pocket Pals for Transportation Customers	525	1/
3	Calendars	2,069	1/
4	Total to be removed	2,606	
5	Adjustment - Pre Tax	$ (2,606)	
6	Tax Rate	37.96%	
7	Tax Effect (L. 5 * L. 6)	989	
8	Adjustment - Post Tax (L. 5 + L. 7)	$ (1,617)	
9	Revenue Conversion Factor	1.61631	
10	Revenue Requirement (L. 8 * L. 9)	$ (2,613)	

Sources:
1/ See PSC 2-58 and 3-24.

Delta Natural Gas Co., Inc.

AG Adjustment No. 14

Remove Athletic Events

Line	Description	Amount	
1	Athletic events, tickets, etc.	$ 1,036	1/
2	Adjustment - Pre Tax	$ (1,036)	
3	Tax Rate	37.96%	
4	Tax Effect (L. 2 * L. 3)	393	
5	Adjustment - Post Tax (L. 2 + L. 4)	$ (643)	
6	Revenue Conversion Factor	1.61631	
7	Revenue Requirement (L. 5 * L. 6)	$ (1,039)	

Sources:
1/ See AG 1-227.

Delta Natural Gas Co., Inc.

AG Adjustment No. 15

Remove Selected Memberships

Line	Description	Amount	
	Specific Items to be Removed		
1	Society of Corporate Secretaries	$ 495	1/
2	Jennings AICPA membership	345	1/
3	Total to be removed	$ 840	
4	Adjustment - Pre Tax	$ (840)	
5	Tax Rate	37.96%	
6	Tax Effect (L. 4 * L. 5)	319	
7	Adjustment - Post Tax (L. 4 + L. 6)	$ (521)	
8	Revenue Conversion Factor	1.61631	
9	Revenue Requirement (L. 7 * L. 8)	$ (842)	

Sources:
1/ See PSC 1-27b, lines 140 and 148, PSC 2-58b and PSC 3-24.

Delta Natural Gas Co., Inc.

AG Adjustment No. 16

Remove Country Club Membership Fees

Line	Description	Amount	
1	Country Club Membership Fees - Acct. 921.07	$ 640	1/
2	Adjustment - Pre Tax	$ (640)	
3	Tax Rate	37.96%	
4	Tax Effect (L. 2 * L. 3)	243	
5	Adjustment - Post Tax (L. 2 + L. 4)	$ (397)	
6	Revenue Conversion Factor	1.61631	
7	Revenue Requirement (L. 5 * L. 6)	$ (642)	

Sources:
1/ See AG 1-245.

Delta Natural Gas Co., Inc.

AG Adjustment No. 17

Adjust AGA Fees

Line	Description	Amount	
1	AGA Dues	$ 29,387	1/
3	2% related to lobbying	588	2/
6	Adjustment - Pre Tax	$ (588)	
7	Tax Rate	37.96%	
8	Tax Effect (L. 6 * L. 7)	223	
9	Adjustment - Post Tax (L. 6 + L. 8)	$ (365)	
10	Revenue Conversion Factor	1.61631	
11	Revenue Requirement (L. 9 * L. 10)	$ (589)	

Sources:
1/ See PSC 1-27.
2/ Case No. 2004-00067, Order Issued November 10, 2004, p. 44.

Delta Natural Gas Co., Inc.

AG Adjustment No. 18

Interest Synchronization

Line	Description	Amount		
1	Pro Forma Rate Base	$	117,817,218	1/
2	Weighted Cost of Debt		4.07%	2/
3	Pro Forma Interest Expense		4,795,161	
4	Company Per Books	$	4,967,706	3/
5	Increase in Taxable Income		172,545	
6	Tax Rate		37.96%	
7	Income Taxes	$	65,498	

Sources:
1/ See Exhibit___(MJM-3), Schedule 1.
2/ See Exhibit___(MJM-2).
3/ See PSC 2-6, Item 6d(2), Schedule 8.

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

Account 369 - Measuring & Regulating Station Equipment

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

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

Account 369 - Measuring & Regulating Station Equipment

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	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	i = 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
2003	2,017,415	2,056,851	78,872	-	0.03835	-	-	2001-03	5,787,011	348,318	23,821	0.06019	0.00412	63.53
2004	2,096,287	2,169,290	146,005	-	0.06731	-	-	2002-04	6,152,627	409,815	3,080	0.06661	0.00050	173.18
2005	2,242,292	2,360,148	261,710	25,999	0.11089	0.01102	28.61	2003-05	6,586,288	486,587	25,999	0.07388	0.00395	58.56
2006	2,478,003	2,578,410	211,114	10,300	0.08188	0.00399	55.29	2004-06	7,107,847	618,829	36,299	0.08706	0.00511	47.42
1951-2006	27,538,483	28,877,892	2,808,823	130,006	0.09727	0.00450	47.79							
Rounded							48.00							

Average Remaining Life Calculation

Average Service Life	48
Weighted Average Age	11
Average Remaining Life	37

Data Source: Response to PSC-2-50(f).

Delta Natural Gas Company
Gas Plant in Service
Calculation of Weighted Average Age

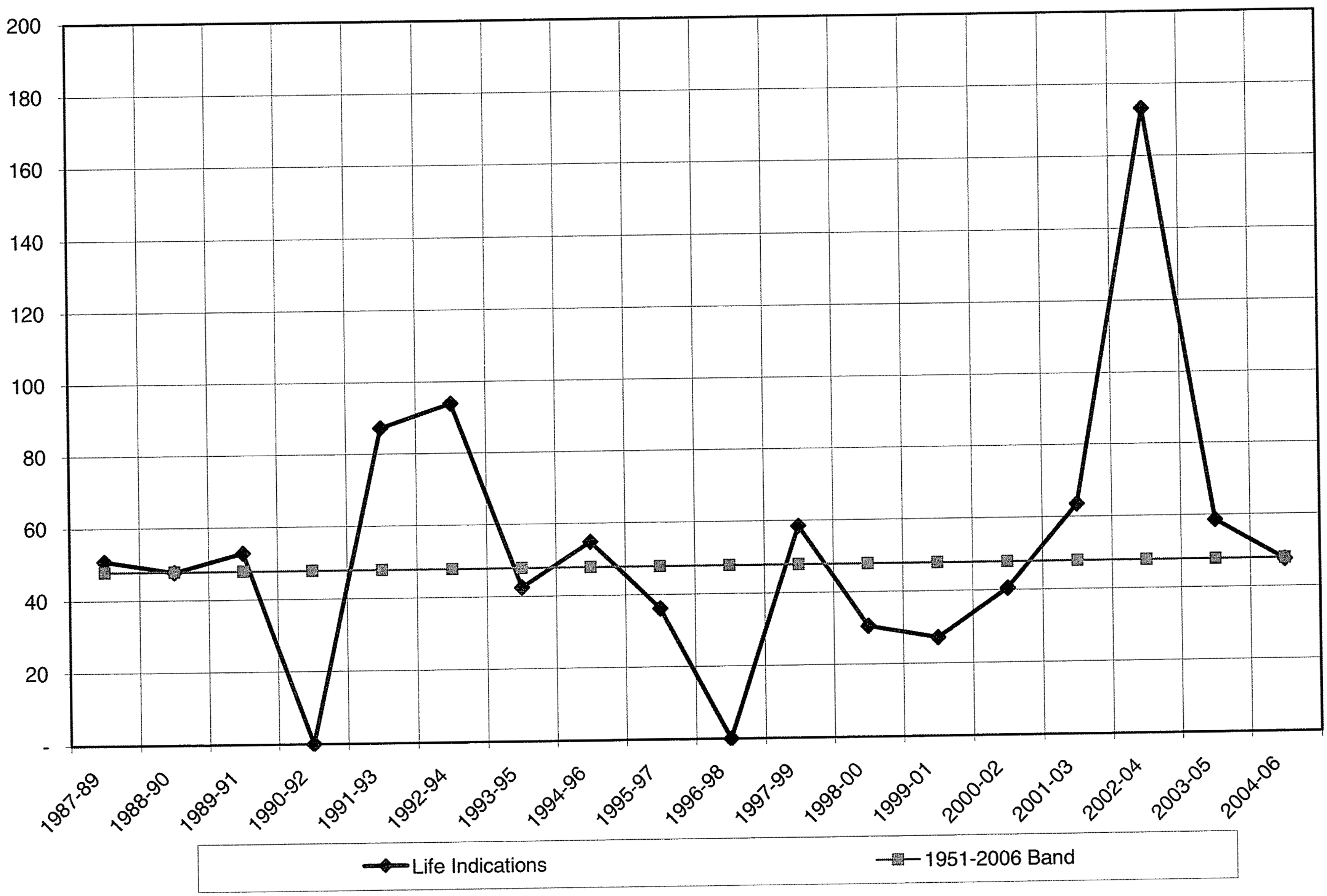
Account 369 - Meas. & Reg. Station Equip.

Year	Single Year Additions	Scaled to Ending Balance	Age	Age Weighting
(a)	(b)	(c)	(d)	(e)=(c)*(d)
1951	604	576	55.5	31,970
1952	-	-	54.5	-
1953	-	-	53.5	-
1954	-	-	52.5	-
1955	2,821	2,690	51.5	138,557
1956	3,317	3,163	50.5	159,755
1957	1,730	1,650	49.5	81,671
1958	4,222	4,027	48.5	195,289
1959	11,640	11,101	47.5	527,309
1960	36,436	34,750	46.5	1,615,855
1961	2,350	2,241	45.5	101,976
1962	143	136	44.5	6,069
1963	1,590	1,516	43.5	65,964
1964	2,469	2,355	42.5	100,076
1965	11,196	10,678	41.5	443,128
1966	12,600	12,017	40.5	486,681
1967	6,054	5,774	39.5	228,065
1968	5,943	5,668	38.5	218,215
1969	18,946	18,069	37.5	677,591
1970	4,457	4,251	36.5	155,151
1971	22,690	21,640	35.5	768,213
1972	1,848	1,762	34.5	60,805
1973	11,003	10,494	33.5	351,540
1974	21,450	20,457	32.5	664,859
1975	68,977	65,784	31.5	2,072,209
1976	25,972	24,770	30.5	755,482
1977	5,860	5,589	29.5	164,869
1978	2,125	2,027	28.5	57,759
1979	11,949	11,396	27.5	313,388
1980	4,539	4,329	26.5	114,716
1981	2,096	1,999	25.5	50,974
1982	2,119	2,021	24.5	49,513
1983	11,231	10,711	23.5	251,713
1984	93,670	89,334	22.5	2,010,026
1985	40,669	38,787	21.5	833,913
1986	4,156	3,964	20.5	81,255
1987	1,551	1,479	19.5	28,845
1988	14,728	14,046	18.5	259,857
1989	88,465	84,370	17.5	1,476,482
1990	36,020	34,353	16.5	566,822
1991	39,795	37,953	15.5	588,273
1992	43,190	41,191	14.5	597,269
1993	44,138	42,095	13.5	568,284
1994	37,008	35,295	12.5	441,189
1995	11,055	10,543	11.5	121,248
1996	19,636	18,727	10.5	196,635
1997	138,952	132,521	9.5	1,258,946
1998	198,341	189,161	8.5	1,607,867
1999	526,196	501,841	7.5	3,763,808
2000	185,729	177,133	6.5	1,151,362
2001	84,508	80,597	5.5	443,281
2002	184,938	176,378	4.5	793,702
2003	78,872	75,221	3.5	263,275
2004	146,005	139,247	2.5	348,118
2005	261,710	249,597	1.5	374,395
2006	211,114	201,343	0.5	100,671
Total	2,808,823	2,678,817	10.75	28,784,883

2006 Ending Balance 2,678,817

Data Source: Response to PSC-2-50(f).

Delta Natural Gas Co.
Geometric Mean 3-Year Rolling Band Analysis
Life Indications - 369 - Measuring & Regulating Station Equipment



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

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

Account 376 - Mains - Distribution

									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)
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
2003	55,253,257	55,974,022	1,493,803	52,274	0.02669	0.00093	200.31	2001-03	164,178,995	4,253,451	222,964	0.02591	0.00136	168.59
2004	56,694,786	57,576,997	1,920,768	156,346	0.03336	0.00272	105.07	2002-04	168,300,745	4,533,284	320,271	0.02694	0.00190	139.68
2005	58,459,208	59,295,178	1,752,060	80,120	0.02955	0.00135	158.26	2003-05	172,846,197	5,166,631	288,740	0.02989	0.00167	141.52
2006	60,131,148	60,777,141	1,344,632	52,646	0.02212	0.00087	228.43	2004-06	177,649,316	5,017,460	289,112	0.02824	0.00163	147.50
1940-2002	936,461,626	967,173,193	65,191,514	3,768,380	0.06740	0.00390	61.71							
Rounded							62.00							

Average Remaining Life Calculation	
Average Service Life	62
Weighted Average Age	16
Average Remaining Life	46

Data Source: Response to PSC-2-50(f).

Delta Natural Gas Company
Gas Plant in Service
Calculation of Weighted Average Age

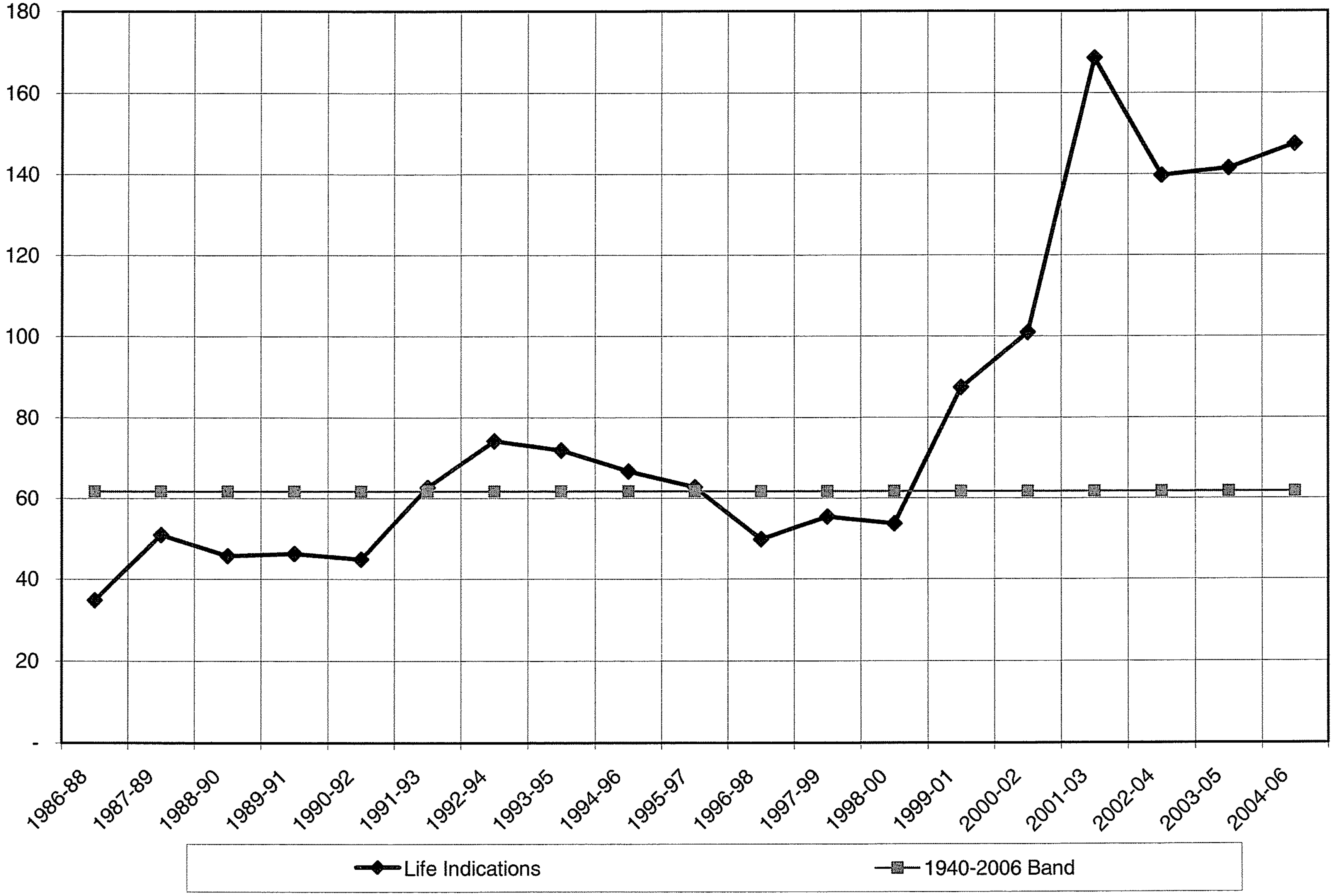
Account 376 - Mains - Distribution

Year	Single Year Additions	Scaled to Ending Balance	Age	Age Weighting
(a)	(b)	(c)	(d)	(e)=(c)*(d)
1940	58,962	55,554	66.5	3,694,322
1941	-	-	65.5	-
1942	-	-	64.5	-
1943	-	-	63.5	-
1944	-	-	62.5	-
1945	-	-	61.5	-
1946	-	-	60.5	-
1947	75,766	71,386	59.5	4,247,489
1948	67,865	63,942	58.5	3,740,612
1949	62,008	58,424	57.5	3,359,359
1950	29,854	28,128	56.5	1,589,249
1951	36,626	34,509	55.5	1,915,241
1952	18,609	17,533	54.5	955,565
1953	12,981	12,231	53.5	654,339
1954	47,353	44,616	52.5	2,342,328
1955	148,499	139,915	51.5	7,205,625
1956	143,937	135,617	50.5	6,848,646
1957	39,727	37,431	49.5	1,852,814
1958	34,326	32,342	48.5	1,568,577
1959	106,509	100,352	47.5	4,766,733
1960	69,660	65,633	46.5	3,051,949
1961	110,606	104,212	45.5	4,741,666
1962	71,538	67,403	44.5	2,999,423
1963	86,884	81,862	43.5	3,560,984
1964	89,514	84,340	42.5	3,584,436
1965	123,728	116,576	41.5	4,837,901
1966	135,264	127,445	40.5	5,161,526
1967	317,430	299,081	39.5	11,813,701
1968	182,038	171,515	38.5	6,603,340
1969	582,335	548,673	37.5	20,575,247
1970	1,455,571	1,371,432	36.5	50,057,270
1971	1,074,050	1,011,965	35.5	35,924,750
1972	324,850	306,072	34.5	10,559,488
1973	448,840	422,895	33.5	14,166,979
1974	294,232	277,224	32.5	9,009,780
1975	409,344	385,682	31.5	12,148,982
1976	201,118	189,492	30.5	5,779,519
1977	215,318	202,872	29.5	5,984,712
1978	316,671	298,366	28.5	8,503,428
1979	723,822	681,982	27.5	18,754,495
1980	646,465	609,096	26.5	16,141,050
1981	1,960,024	1,846,725	25.5	47,091,495
1982	1,666,448	1,570,119	24.5	38,467,925
1983	1,579,871	1,488,547	23.5	34,980,853
1984	1,436,971	1,353,907	22.5	30,462,913
1985	1,581,605	1,490,181	21.5	32,038,885
1986	1,813,432	1,708,607	20.5	35,026,443
1987	1,928,903	1,817,403	19.5	35,439,363
1988	2,394,747	2,256,319	18.5	41,741,906
1989	823,954	776,326	17.5	13,585,697
1990	2,593,632	2,443,708	16.5	40,321,177
1991	3,006,462	2,832,674	15.5	43,906,450
1992	2,091,957	1,971,032	14.5	28,579,963
1993	2,514,631	2,369,273	13.5	31,985,190
1994	2,265,544	2,134,585	12.5	26,682,310
1995	3,168,792	2,985,621	11.5	34,334,638
1996	2,615,832	2,464,624	10.5	25,878,557
1997	2,773,515	2,613,193	9.5	24,825,330
1998	4,460,035	4,202,224	8.5	35,718,902
1999	3,293,998	3,103,589	7.5	23,276,919
2000	3,187,950	3,003,671	6.5	19,523,863
2001	1,640,935	1,546,081	5.5	8,503,446
2002	1,118,713	1,054,046	4.5	4,743,207
2003	1,493,803	1,407,454	3.5	4,926,089
2004	1,920,768	1,809,738	2.5	4,524,346
2005	1,752,060	1,650,783	1.5	2,476,174
2006	1,344,632	1,266,906	0.5	633,453
Total	65,191,514	61,423,134	15.77	968,377,022

2006 Ending Balance	61,423,134

Data Source: Response to PSC-2-50(f).

Delta Natural Gas Co.
Geometric Mean 3-Year Rolling Band Analysis
Life Indications - 376 - Distribution Mains



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

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**	**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)
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
2003	2,773,387	2,819,239	102,667	10,963	0.03642	0.00389	84.03	2001-03	8,202,720	295,101	42,659	0.03598	0.00520	73.11
2004	2,865,091	2,918,247	112,534	6,222	0.03856	0.00213	110.28	2002-04	8,469,411	308,744	27,804	0.03645	0.00328	91.41
2005	2,971,403	3,023,235	110,798	7,135	0.03665	0.00236	107.52	2003-05	8,760,721	325,999	24,320	0.03721	0.00278	98.39
2006	3,075,066	3,110,340	82,818	12,270	0.02663	0.00394	97.57	2004-06	9,051,822	306,150	25,627	0.03382	0.00283	102.19
1940-2002	41,884,605	43,457,412	3,304,796	159,182	0.07605	0.00366	59.92							
Rounded							60.00							

Average Remaining Life Calculation	
Average Service Life	60
Weighted Average Age	14
Average Remaining Life	46

Data Source: Response to PSC-2-50(f).

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

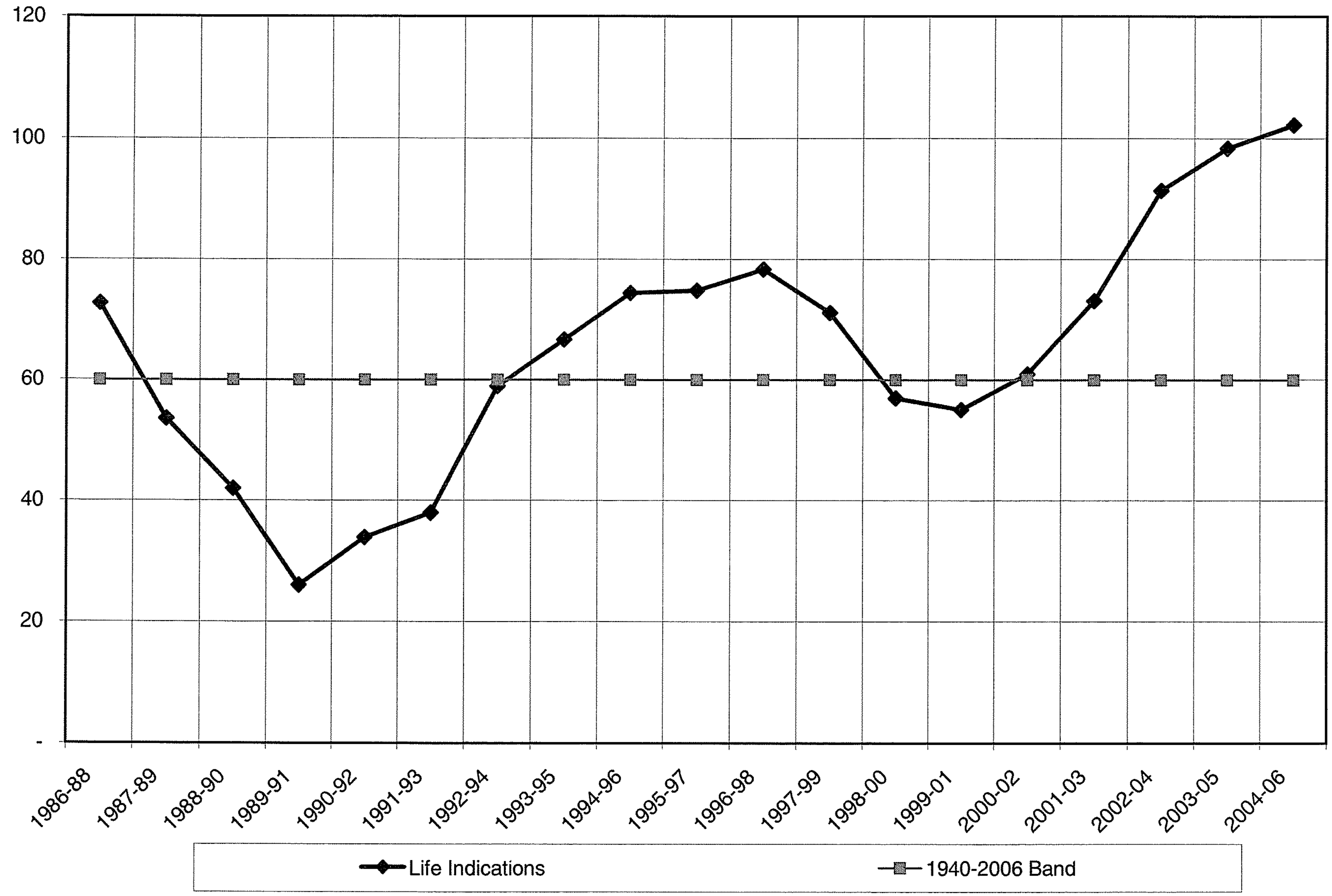
Account 382 - Meter and Regulator Installations

Year	Single Year Additions	Scaled to Ending Balance	Age	Age Weighting
(a)	(b)	(c)	(d)	(e)=(c)*(d)
1940	386	367	66.5	24,433
1941	-	-	65.5	-
1942	-	-	64.5	-
1943	-	-	63.5	-
1944	-	-	62.5	-
1945	-	-	61.5	-
1946	-	-	60.5	-
1947	291	277	59.5	16,481
1948	543	517	58.5	30,235
1949	1,057	1,006	57.5	57,850
1950	1,120	1,066	56.5	60,232
1951	1,784	1,698	55.5	94,243
1952	293	279	54.5	15,199
1953	394	375	53.5	20,064
1954	1,666	1,586	52.5	83,252
1955	2,929	2,788	51.5	143,578
1956	8,754	8,332	50.5	420,783
1957	8,202	7,807	49.5	386,443
1958	6,222	5,922	48.5	287,232
1959	4,846	4,613	47.5	219,098
1960	3,986	3,794	46.5	176,421
1961	3,306	3,147	45.5	143,178
1962	9,394	8,942	44.5	397,898
1963	1,800	1,713	43.5	74,529
1964	1,800	1,713	42.5	72,815
1965	2,280	2,170	41.5	90,062
1966	2,088	1,987	40.5	80,491
1967	4,152	3,952	39.5	156,104
1968	5,823	5,543	38.5	213,387
1969	8,651	8,234	37.5	308,787
1970	8,413	8,008	36.5	292,284
1971	6,017	5,727	35.5	203,315
1972	6,795	6,468	34.5	223,136
1973	8,877	8,449	33.5	283,056
1974	5,641	5,369	32.5	174,502
1975	4,065	3,869	31.5	121,880
1976	2,843	2,706	30.5	82,535
1977	2,209	2,103	29.5	62,027
1978	1,604	1,527	28.5	43,512
1979	4,463	4,248	27.5	116,821
1980	5,200	4,950	26.5	131,163
1981	12,046	11,466	25.5	292,377
1982	66,540	63,335	24.5	1,551,707
1983	99,610	94,812	23.5	2,228,084
1984	94,296	89,754	22.5	2,019,466
1985	67,324	64,081	21.5	1,377,746
1986	69,688	66,331	20.5	1,359,792
1987	60,219	57,318	19.5	1,117,709
1988	71,400	67,961	18.5	1,257,276
1989	385,719	367,140	17.5	6,424,951
1990	147,697	140,583	16.5	2,319,618
1991	118,996	113,264	15.5	1,755,597
1992	170,332	162,128	14.5	2,350,851
1993	142,352	135,495	13.5	1,829,187
1994	160,617	152,881	12.5	1,911,007
1995	148,177	141,040	11.5	1,621,957
1996	150,837	143,572	10.5	1,507,502
1997	149,850	142,632	9.5	1,355,006
1998	172,095	163,806	8.5	1,392,348
1999	155,766	148,263	7.5	1,111,974
2000	122,090	116,209	6.5	755,360
2001	98,891	94,128	5.5	517,702
2002	93,543	89,037	4.5	400,668
2003	102,667	97,722	3.5	342,026
2004	112,534	107,114	2.5	267,784
2005	110,798	105,461	1.5	158,192
2006	82,818	78,829	0.5	39,414
Total	3,304,796	3,145,614	13.53	42,572,328

2006 Ending Balance 3,145,614

Data Source: Response to PSC-2-50(f).

Delta Natural Gas Co.
Geometric Mean 3-Year Rolling Band Analysis
Life Indications - 382 - Meter and Regulator Installations



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 federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array 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 and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

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

Mr. Majoros conducted and assisted in 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 provided onsite management accounting and controllership assistance to a municipal electric and water utility. 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), and 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.

Controller/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

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility

Federal Courts

Date	Jurisdiction / Agency	Docket	Utility
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Legislatures

Date	Jurisdiction / Agency	Docket	Utility
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act

Federal Regulatory Agencies

Date	Jurisdiction / Agency	Docket	Utility
1979	FERC-US 19/	RP79-12	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 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

State Regulatory Agencies

Date	Jurisdiction / Agency	Docket	Utility
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

Michael J. Majoros, Jr.

1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison 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.
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.

Michael J. Majoros, Jr.

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
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

Michael J. Majoros, Jr.

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
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 40/	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
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Florida 50/ 54/	030157-EI	Progress Energy Florida
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado

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 Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	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

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 Assn. of State 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.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	60/ Colorado Office of Consumer Counsel
29/ IN Office of Utility Consumer Counselor	61/ MD State Senator Paul G. Pinsky
30/ Unitel (AT&T – Canada)	62/ MD Speaker of the House Michael Busch
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS CO., INC. FOR AN ADJUSTMENT OF GAS RATES	)))	Case No. 2007-00089

AFFIDAVIT OF MICHAEL MAJOROS

District of Columbia)
)
)

Michael Majoros, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael Majoros

SUBSCRIBED AND SWORN to before me this 10th day of August, 2007.

Angel L. Finch
NOTARY PUBLIC

My Commission Expires: March 14, 2011

ANGEL L. FINCH NOTARY PUBLIC DISTRICT OF COLUMBIA