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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	))))	CASE NO: 2004-00067

REBUTTAL TESTIMONY OF WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT THE PRIME GROUP, LLC

Filed: August 9, 2004

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 2004-00067, in the Matter of: An Adjustment of Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared direct testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 2004-0067 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his rebuttal testimony in ~~such~~ case.

WILLIAM STEVEN SEELYE

STATE OF KENTUCKY)
)
COUNTY OF OLDHAM)

Subscribed and sworn to before me by ~~John B. Brown,~~ PATSY W. Littrell this the 5TH day of Aug, 2004.

My Commission Expires: 12-02-06

Patsy W. Littrell
Notary Public, State at Large, Kentucky

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut direct testimony presented by Michael J. Majoros, Robert J. Henkes and David H. Brown Kinloch in this proceeding.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Depreciation Study, (III) Year-End Adjustment, (IV) Cost of Service Study, and (V) Revenue Allocation and Rate Design.

II. DEPRECIATION STUDY

Q. Do you have any concerns about Mr. Majoros's recommendations in this proceeding?

A. Yes. The depreciation rates that Delta is proposing are significantly lower than its current rates. Mr. Majoros proposes to lower Delta's depreciation rates even more. Setting aside for a moment the technical complaints that I have with his approach, I feel that Mr. Majoros's proposal represents too abrupt a change in Delta's depreciation rates. The following table compares Delta's current depreciation rates to (i) the rates that we recommend and to (ii) the rates that Mr. Majoros recommends for those plant account for which we are in disagreement:

ACCT NO	DESCRIPTION	DELTA'S CURRENT RATES	DELTA'S PROPOSED RATES	MAJOROS'S PROPOSED RATES
351	Storage – Struc & Imp	3.00%	2.50%	2.22%
352	Storage Wells	4.50%	2.78%	2.34%
35201	Storage Rights	4.50%	2.78%	1.98%
35202	Storage Reservoirs	4.50%	2.78%	1.91%
35203	Non-recov Natural Gas	4.50%	2.78%	1.90%
353	Storage Lines	4.50%	2.78%	2.17%
354	Storage Comp Stat Equip	4.50%	2.78%	1.61%
355	Storage Meas & Reg Equip	3.00%	2.78%	2.25%
356	Storage Purif Equip	4.50%	2.78%	2.16%
357	Storage Other Equip	10.00%	3.33%	1.15%
369	Trans Meas & Reg Stat Equip	3.00%	3.16%	2.02%
376	Dist Mains	2.50%	2.50%	1.59%
378	Dist Meas & Reg Stat – Gen	3.00%	3.03%	2.66%
379	Dist Meas & Reg Stat – Cty Gate	3.00%	2.96%	2.52%
380	Dist Services	2.50%	2.50%	1.59%
382	Dist Meter & Reg Inst	3.00%	4.17%	2.01%
383	Dist House REg	3.00%	3.88%	4.19%
385	Dist Ind Meter Sets	3.00%	2.38%	2.10%

As can be seen from this table, Delta is proposing lower (in most cases, significantly lower) depreciation rates for virtually all of these accounts. Mr. Majoros, on the other hand, proposes a much more significant reduction in most of these rates. For example, Delta is proposing to reduce the depreciation rate for Account 354 – Storage Compressor Station Equipment from 4.50% to 2.78%. Mr. Majoros proposes to reduce the rate to 1.61%. Delta is proposing to reduce the depreciation rate for Account 357 – Storage Other Equipment from 10.0% to 3.33%. Mr. Majoros proposes to reduce this rate to 1.15%. Without even considering the methodological problems with his analysis, Mr. Majoros's proposed rates represent too radical a movement in Delta's depreciation rates.

Mr. Majoros's clarion call for lower depreciation rates – a nationwide clarion call, I might add – is premised on the idea that, "An excessive depreciation rate can unreasonably increase the utility's revenue requirement and resulting service rates; therefore unnecessarily charging millions of dollars to a utility's customers." (Direct Testimony of Michael J. Majoros, page 13.) This short-sighted and ultimately flawed premise indicates an unsophisticated understanding of the utility ratemaking process. By proposing understated depreciation rates, Mr. Majoros's proposal has the effect of pushing costs further out into the future, which causes customers ultimately to pay more than they would otherwise.

Mr. Majoros's perennial call for lower depreciation rates is not unlike a car buyer being told that he can afford to buy a car if he were only willing to finance it over 10 years rather than, say, 3 years. In fact, lowering a loan payment by extending the amortization period is exactly analogous to Mr. Majoros's proposition. Loan payments on a car can certainly be lowered by simply amortizing the loan over 10 years rather than 3 years, but over the life of the loan, the car buyer will have paid much more for the car because of interest. Similarly, by proposing understated depreciation rates, Mr. Majoros's proposal has the effect of deferring cost recovery further out into the future, which ultimately results in higher rates being paid by customers. The depreciation expenses included in the utility's revenue requirements might indeed be lowered by adopting understated depreciation rates, but the interest charges, return on investment and associated income taxes that must ultimately be paid by customers on the undepreciated plant will be increased significantly over the life of the property.

One of the principal reasons that ratepayers in Kentucky generally enjoy low utility rates is that the Commission has not engaged in the practice of deferring cost recovery at every opportunity. Setting depreciation rates that are too low may indeed result in lower utility rates in the short term, but in the long run customers end up paying more. Mr. Majoros's proposal, if adopted, would have the effect of preserving the value of the utility assets on the utility's books for a much longer period, resulting in customers paying much more carrying costs (specifically, interest charges, return and income taxes) than they otherwise should. For Mr. Majoros, lowering a utility's depreciation expenses represents an easy way of paring back a rate increase. This practice, however, will cause customers to pay much more over the long run.

Q. Since higher depreciation rates reduce a utility's revenue requirements over time, are you suggesting that utilities should use artificially overstated depreciation rates?

A. Not at all. Although higher depreciation rates will indeed result in lower utility revenue requirements over time, I am not suggesting that depreciation rates should be artificially overstated. Depreciation rates should reflect a reasonable estimate of the remaining lives of the utility property. The purpose of depreciation is to allocate the value of assets over the useful life of the property. Using a depreciation rate that reflects the average service life of the property helps ensure that the customers receiving service from the property are paying utility rates that appropriately reflect carrying costs on the property.

Q. What guidance were you given by Delta in preparing the depreciation study?

A. The only guidance I was given was to prepare a study that produced reasonable, objective and supportable depreciation rates. The management of the utility offered no suggestions whatsoever as to what those depreciation rates should be. Therefore, we proposed depreciations rates that reasonably represented the remaining life of the assets.

Q. Did Mr. Majoros accept any of your recommendations?

A. Yes. Although he accepts many of my recommendations, I feel that his proposed modifications will result in understated depreciation expenses, which will cause Delta's customers to incur excessive costs over the long run.

Q. Did Mr. Majoros disagree with any of your proposed service lives?

A. Yes. He disagreed with the proposed service lives for three accounts – Account 369 – Measuring and Regulation Station Equipment, Account 376 – Distribution Mains, and Account 382 – Meter and Regulator Installation. For Accounts 376 and 382, Mr. Majoros is proposing significantly longer average service lives. Extending the average service life for Account 376 – Distribution Mains would have a significant impact on Delta's depreciation expenses. Seelye Rebuttal Exhibit 1 shows the impact of each of Mr. Majoros's recommendations. As can be seen from this exhibit, his proposed modification to the depreciation rate for Account 376 would have, by far, the most significant impact.

Q. What problems did he have with your proposed service lives for these three accounts?

A. On page 18 of his testimony, Mr. Majoros indicated that he could not review the Simulated Property Records ("SPR") analysis that we used to develop the service lives for these accounts. I am perplexed by this comment. The Excel-VBA model that was used to produce the results was provided on a compact disk ("CD") attached to the response to Question 17 of the Commission's Second Data Request dated May 11, 2004. The model was contained in the files labeled "Seelye Exhibit 7 Model1.bas", "Seelye Exhibit 7 Model2.bas", "Seelye Exhibit 7 Model3.bas", and Seelye Exhibit 7 Model4.bas". However, I am even more perplexed by the fact that Mr. Majoros was clearly aware that we provided our model because he or someone else in his organization went to the trouble to load our SPR model in the Excel spreadsheet containing his work papers. See the Excel spreadsheet labeled "SPR Workpapers" that Mr. Majoros provided in response to Question 6 of Delta's data request to Attorney General.

Q. What methodology did Mr. Majoros use to estimate the service lives for these three accounts?

A. It is not clear. In a data request response, he indicates that he "selected a life based on the results of his SPR analysis". (Response of the Attorney General to Question 10 of Delta's data request.) However, a review of the results of his SPR analysis does not support this assertion. For example, Mr. Majoros's SPR results for Account 376 shown on page 10 of Exhibit___(MJM-1) do not support the selection of a 52 S0 curve. Although he claims to have used an SPR analysis to arrive at his recommended average service life and survivor curve, he seems to have relied on a Geometric Mean Turnover ("GMT") analysis to estimate the average service life and a Simulated Plant Record analysis to select the dispersion curve.

Q. Please explain the differences between SPR analysis and GMT analysis.

A. An SPR analysis is a methodology for determining the best fitting dispersion curve (Iowa curve) and service life by applying each type of curve to actual plant additions for a number of years and finding the average service life that minimizes the sum of squared deviations between the actual plant balances and the estimated balances computed by applying the curve to the plant additions. GMT is one of the more simplified forms of a "turnover" model which estimates the service life of a property group by measuring the time it takes for plant retirements to exhaust a previous plant balance. A GMT analysis computes the service life based on the following geometric mean formula:

$$life\,estimate = \frac{1}{\sqrt{ar}}$$

Where: a is the average additions ratio

r is the average retirements ratio

Q. Are there any problems with the GMT methodology?

A. Yes. The most significant problem with a GMT analysis – and the main reason that we did not use it in our study – is that it does not provide any indication of the dispersion curve that should be used.

Q. Does Mr. Majoros's SPR analysis produce radically different results than from his GMT analysis for Accounts 376 and 382?

A. Yes. Mr. Majoros's SPR analysis diverges radically from his own GMT analysis. His SPR analysis also diverges radically from our SPR analysis, even though he was able to confirm the reasonableness of our SPR analysis for numerous other plant accounts. His SPR analysis would support absurdly high service lives for Accounts 376 and 382, which makes me questions his analysis. His SPR analysis indicates that the best fitting dispersion curve for Account 376 – Distribution Mains is an R0.5 curve with a 77 year life. However, he proposes an S0 curve with a 52 year life. Our SPR analysis indicated that the best fitting dispersion curve was an R3 curve with a service life of 37 years. Likewise, his SPR analysis indicates that the best fitting dispersion curve for Account 382 – Meter & Regulator Installation is a S0 curve with a 63 year life. However, he proposes an S1 curve with a 44 year life. Our SPR analysis indicated that the best fitting dispersion curve was an S1 curve with a service life of 40 years.

Q. Did Mr. Majoros provide the model used to perform his SPR analysis?

A. No. In Question No. 6 of the Delta's data request to the Attorney General, we asked Mr. Majoros to provide a copy of his SPR model. In his response to the data request, he indicated that his model is "proprietary" and refused to provide it. Delta's attorney followed up on this issue with the Attorney General, and Mr. Majoros remains adamant about his refusal to provide his SPR model.

Q. Can the results of Mr. Majoros's SPR analysis be independently verified?

A. No. Not only did he not provide a copy of his model, he failed to provide any detailed statistics from his model that might be used to validate the results of his SPR analysis. Likewise, he failed to provide the algorithms that were used to compute the "Sum of Squared Differences" or "Index of Variation" shown on pages 3, 10, and 17 of Exhibit ___(MJM-1). It is simply impossible to validate the results of his SPR analysis, which differs significantly from both Mr. Majoros's own GMT analysis and our SPR analysis, from the information that has been provided. His results cannot be validated without being able to examine his model or to inspect detailed statistical outputs from his SPR model. His model is a "black box" which produces starkly different results than the results from our model. Since (i) his SPR model cannot be examined and since (ii) the results of his model cannot be independently reproduced, Mr. Majoros's SPR results shown on pages 3, 10, and 17 of Exhibit ___(MJM-1) are without probative value. Consequently, his recommendations for Accounts 369, 376 and 382 should be ignored.

Q. Is there is a solid basis for using your recommendations for Accounts 369, 376, and 382 as opposed to Mr. Majoros's recommendations?

A. Yes, for a number of reasons. First, a working copy of our model was provided to all of the parties in the proceeding, including to the Attorney General's witness Majoros. Consequently, our model was made available to be scrutinized, critiqued and validated. Second, with the exception of three accounts, Mr. Majoros was able to validate the results of our SPR model using his own GMT analysis. For one of the three accounts -- Account 382 – Meter & Regulator Installation – his GMT analysis produced results that were reasonably close to ours – a 44-year S1 curve versus a 40-year S1 curve.

Q. Is there any reason to suspect that his SPR and GMT analysis for Accounts 369, 376, and 382 is flawed?

A. Yes, especially his results for Account 376. He failed to properly account for the fact that in 1989 costs that were recorded in Account 376 – Distribution Mains were transferred by Delta to Account 380 – Services. Mr. Majoros treated these transfers as if they were new facilities, which is not the case This failure has the effect of making the average age of Account 376 seem older than it really is, thus causing Mr. Majoros to overstate the average life for this account. Unlike an SPR analysis, such as the one we performed, a GMT analysis cannot readily account for an aged transfer such as the one that took place in 1989 for Account 376, which underscores one of the problems with this methodology. In many cases, where transfers are small, the effect of ignoring the age of the transfers would not have a significant impact on the service life. However, the transfer from Account 376 to Account 380 represented almost approximately 8% of the account balance for Account 376. Therefore, the age of the transferred plant cannot be ignored in estimating the service life of the property. I suspect that his failure to properly account for the age of the transferred property is one of the reasons that his service life estimates for Account 376 diverges so much from ours.

Presumably, Mr. Majoros also failed to consider these transfers when he performed his SPR analysis. However, it is impossible to determine anything about what he did with his SPR model, since he failed to provide any of the details concerning his analysis.

Q. Do Mr. Majoros's recommended service lives for Accounts 369, 376, and 382 have a major impact on Delta's pro-forma depreciation expenses?

A. Mr. Majoros's recommended service lives for Account 369 and 382 do not have a major impact on Delta's depreciation expenses. He proposes to use a 45 R2.5 curve for Account 369 instead of a 39 S3 curve as proposed in our study. This change would decrease Delta's pro-forma depreciation expenses by $19,504. He proposes to use a 44 S1 curve for Account 382 instead of a 40 S1 curve as proposed in our study. This change *ceteris paribus* would increase Delta's pro-form depreciation expenses by $55,296.

Mr. Majoros's proposed service life and dispersion curve for Account 376 has a much more significant impact. He proposes to use a 52 S0 curve for Account 376, which would result in a depreciation rate of 1.59%. We are proposing the leave the depreciation rate at the current level, which is 2.50%. As I indicated earlier, our SPR analysis indicated that the best fitting dispersion curve was 37 R3, which supported a depreciation rate slightly below Delta's current depreciation rate of 2.50%. Mr. Majoros's change would decrease Delta's pro-forma depreciation expenses by $517,188. Mr. Majoros also proposes to lower the depreciation rate for Account 380 – Services from 2.50% to 1.59%. This modification, which has the second largest impact on Delta's depreciation expenses, results in a reduction in depreciation expenses of $98,798. Although he doesn't specifically address this modification, he is presumably using the same depreciation rate for Account 380 – Services that he proposes for Account 376 – Mains.

In addition to his recommendation diverging radically from our SPR analysis, I believe that his proposed accrual rate of 1.59% for Accounts 376 and 380 represent too much of a departure from Delta's current depreciation rate of 2.50% for Account 376. Distribution Mains represents the single largest cost item in Delta's property records. Caution should thus be exercised in making radical adjustments to the depreciation rate for this account. As I mentioned earlier in my testimony, unduly extending the lives of utility assets ultimately causes customers to pay significantly more over time in interest charges, return and income taxes.

Q. How did Mr. Majoros handle net salvage in developing his proposed depreciation rates?

A. He ignored them. A straight-line remaining life depreciation rate is computed as follows:

$$depreciaiton\ rate = \frac{100\% - u - c}{e}$$

Where: u is percentage of plant already depreciated c is the percentage of future net salvage

e is the estimated average remaining life of the plant

In computing his proposed depreciation rates, Mr. Majoros used a 0% net salvage percentage. Instead of following the traditional approach of incorporating net salvage in the development of the depreciation rates, he proposes to amortize net salvage over 5-years. This non-standard approach, is not based on any sort of empirical analysis.

Q. Does Mr. Majoros also propose to lower the depreciation rates for storage plant?

A. Yes. He argues that our proposed depreciation rates were developed using whole-life technique rather than the remaining life technique. Mr. Majoros's observation is valid. The depreciation rates that we proposed do not correspond to the average remaining life that we indicated. However, his criticism carries little weight. In developing our proposed depreciation rates for Storage we examined the depreciation rates – and not the average service live or remaining lives – of other utilities in the region. Accordingly, we developed proposed depreciation rates for the storage accounts and computed the remaining life as a function of the depreciation rates. A computation error was made in computing the relationship between the remaining life and the depreciation rate. As we indicated in the study there was not sufficient cost data to perform a SPR analysis (or any other semi-actuarial analysis) on storage plant. The depreciation rate and the corresponding (and miscalculated) remaining life were based purely on judgment. In developing his proposed depreciation rates for storage plant, Mr. Majoros is giving more weight to the remaining life estimates than is due.

Q. Do you have a strong objection to Mr. Majoros's proposed depreciation rates for storage?

A. Not a strong objection. As I've indicated, our proposed rates were based on judgment. My only concern with Mr. Majoros's proposal is that his recommended depreciation rates for storage plant represent too radical a departure from Delta's current rates, which could result in customers paying higher carrying costs in the form of return on investment, interest charges, and income taxes over the useful life of the storage facilities. Much of Delta's storage investment is relatively new. A more cautious approach would be to adopt the depreciation rates that we have proposed in this proceeding, and allow Delta to analyze the depreciation rates for storage in greater detail in future studies, when more information may be available.

IV. YEAR END ADJUSTMENT

Q. What is a year-end adjustment?

A. A year-end adjustment is a pro-forma adjustment that has been used in Kentucky for a number of years that typically compares the number of customers served at the end of the test year to the average number of customers during the test year. An adjustment to revenues is made that reflects the difference in customers multiplied by the average net revenue per customer. A corresponding adjustment to expenses is made by applying an operating ratio to the revenue adjustment.

Q. Is Delta proposing a year-end adjustment in this proceeding?

A. No.

Q. Why didn't Delta propose a year-end adjustment?

A. The customer growth indicated by applying a standard year-end adjustment (using either 12- or 13-month average numbers of customers) was not consistent with the fact that Delta experienced a decrease in the number of customers from the beginning to the end of the test year. Delta served 40,027 customers as of December, 2002, compared to 39,610 customers as of December, 2003, indicating a decrease of 417 customers during the year. One of the reasons for making a year-end adjustment is to account for changes in the utility's customer base over the course of the test year. Comparing the number of customers at the end of the test year to the average number of customers during the test year would indicate that there was customer growth during the year. However, a better measurement of whether there was customer growth is to compare the number of customers served in December, 2002, to the number of customers served in December, 2003. There is typically a seasonal pattern in the number of customers served by a utility. For a gas utility, the number of customers tends to decrease during the summer months and increase during the winter months. Therefore, the number of customers served during December will tend to be higher than the number of customers served during June through September. Consequently, the results of a year-end adjustment will vary considerably depending on whether the end of the test year occurs during the winter or during the summer. This is one of the reasons that it is important to compare the number of customers at the end of the test year to the number of customers served the same month in the prior year.

Q. Does Mr. Henkes propose a year-end adjustment?

A. Yes.

Q. What is his justification?

A. He argues that a year-end adjustment was submitted by LG&E in its most recent rate case (Case No. 2003-00433) and that I was the sponsoring witness for this adjustment.

Q. Is there a reason that LG&E would make a year-end adjustment and Delta would not?

A. Yes. LG&E experienced customer growth from the beginning of the test year to the end of the test year. LG&E served 308,719 gas customers as of September, 2002, compared to 311,815 customers as of September, 2003, indicating an increase of 3,096 gas customers during the year. Likewise, LG&E served 386,059 electric customers as of September, 2002 compared to 389,473 customers as of September, 2003, indicating an increase of 3,414 electric customers during the year. Thus, there was a justification for a year-end adjustment for LG&E.

Q. What methodology does Mr. Henkes use?

A. He presents two methods for computing a year-end adjustment. In RJH-6A he uses the more traditional approach which simply compares the number of customers at the end of the test year to the 13-month average. In RJH-6B his develops his adjustment by applying a 5-year compound growth rate to the 13 month average customers. This second methodology was rejected by the Commission in LG&E's recent rate case.

Q. Are there any problems with the methodology used by Mr. Henkes to calculate the year-end adjustment shown in RJH-6A?

A. Yes, there are a number of problems with Mr. Henkes's calculations. First, in computing the revenue impact of his adjustment, Mr. Henkes fails to take into account that Delta's rates are blocked. Second, he fails to reflect that there was a reduction in Interruptible Transportation customers at the end of the test year compared to the 13-month average. There were 28 Interruptible Transportation customers at the end of the test year compared to 30 customers on average for the 13-month period ended December 31, 2003.

Q. Have you prepared an exhibit correcting these problems?

A. Yes. These problems are corrected in Seelye Rebuttal Exhibit 2. This exhibit indicates that the adjustment would be $70,059 instead of $209,654 recommended by Mr. Henkes.

Q. Are you recommending that the Commission use the adjustment shown in Seelye Rebuttal Exhibit 2.

A. No. Because Delta has seen a reduction in the number of customers from December, 2002, to December, 2003, I do not believe that an adjustment is warranted. In fact, one could argue that a more appropriate methodology would be to make a downward adjustment to revenues to reflect the decrease in customers. However, if the Commission chooses to apply the traditional methodology, then the adjustment shown in Seelye Rebuttal Exhibit 2 should be used instead of the adjustments proposed by Mr. Henkes.

IV. COST OF SERVICE STUDY

Q. Did Mr. Brown Kinloch recommend any changes to the cost of service study that you performed for Delta?

A. Yes. He recommends changing the classification of distribution mains in the cost of service study. This is the only change to the cost of service study that Mr. Brown Kinloch recommends. In our cost of service study, we performed a weighted least squares analysis to determine the percentage of distribution mains that should be classified as either customer-related or demand-related. The weighted least squares methodology was applied to actual plant cost data for each size of distribution mains from Delta's continuing property records. Because he didn't like the results of the analysis, he removed all of the main sizes except for two – (i) 2-inch plastic mains and (ii) 4-inch plastic mains. He then performed a regression analysis using only these two data points.

Q. Is it statistically meaningful to run a regression analysis using only two points?

A. No. A regression analysis that uses only two data points is simply an exercise in connecting the dots. At least three data points are required to perform a regression analysis; otherwise it is an "extrapolation" rather than a "least squares". Any regression analysis performed using only two data points will by necessity produce an R-Square of 1.0, a perfect fit. He could have selected any two data points and produced an R-Square of 1.0. However, the portion of plant identified as customer-related and demand-related would have been radically different, depending on the two points arbitrarily selected.

Q. Does he provide a rationale for the two points he selected?

A. Yes. The two data points selected were the sizes of main with the largest amount of pipe.

Q. Doesn't a weighted regression analysis fully account for the differences in the amounts of mains by pipe size?

A. Yes. Because a weighted regression analysis weights each size of pipe by the number of feet installed, our analysis fully accounts for what Mr. Brown Kinloch is trying to do by removing all data points except for two pipe sizes. In our weighted least squares analysis, 2-inch plastic mains and 4-inch plastic mains were given the greatest weight in determining the customer-related component of mains. The 2-inch plastic mains were given a 57.35% weight (4,261,667 ft ÷ 7,430,681 ft) and 4-inch plastic mains were given a 17.35% weight (1,289,179 ft ÷ 7,430,681 ft), while 6-inch plastic mains, for example, were only given a weight of 0.79% (58,933 ft ÷ 7,430,681 ft). In his connect-the-two-dots approach, Mr. Brown Kinloch arbitrarily discarded 25.3% of the relevant information.

Q. Mr. Brown Kinloch compares the customer-related component from LG&E's weighted least squares analysis from Case No. 2000-080 to results of Delta's weighted regression analysis in this proceeding. Is this a meaningful comparison?

A. No. Mr. Brown Kinloch claims that a 20% customer component is more representative, but he offers no empirical support for reasonableness of 20%, except that LG&E's cost of service study submitted four years ago produced a 17.30% customer component. I have personally prepared and supervised the preparation of cost of service studies all over the country. The Prime Group has prepared over 100 cost of service studies for rural and urban gas and electric utilities. We have found that in using a weighted least squares analysis, rural utilities (utilities with low customer densities) have significantly higher customer cost components than urban utilities (utilities with high customer densities). The principal reason for this is that rural utilities must install longer lengths of pipe or longer spans of conductor per customer than urban utilities. Rural gas utilities must perform more trenching than an urban gas utility such as LG&E to serve a customer. As a result, the comparison of the results for Delta with the much more urban LG&E is meaningless.

Q. Is there any reason to be concerned about the R-Square statistic for Delta?

A. No. The R-Square from the weighted least squares analysis for Delta was 0.8385. This means that 83.85% of the variability in the data can be examined by the independent variable in the regression analysis, i.e., the size of the mains. This is a very respectable result.

Q. Is there any reason to conclude that the input data for Delta's weighted regression analysis is "irregular"?

A. No. A high R-Square in this type of analysis usually suggests that the data is sound. Generally, I try to avoid arbitrarily removing data points from a regression analysis. There are rigorous statistical methodologies for the detection and removal of outliers in statistical data. (For example, see Douglas M. Hawkins, *Identification of Outliers*, 1980, or Peter J. Rousseeuw and Annick M. Leroy, *Robust Regression and Outlier Detection*, 1987.) Mr. Brown Kinloch did not use a rigorous approach in removing any of the data points he removed.

Q. Then is it your conclusion that Mr. Brown Kinloch's modification to Delta's cost of service study should be rejected?

A. Yes.

V. REVENUE ALLOCATION AND RATE DESIGN

Q. Has Mr. Brown Kinloch proposed to allocate a portion of the increase to Delta's special contract customers?

A. Yes. Mr. Brown Kinloch proposes to increase the transportation rates for Delta's four special contract customers by $63,636, which represents a 10.08% increase to these customers.

Q. Do the contracts for these four customers establish a fixed price over the term of the agreements?

A. Yes. Delta cannot propose to increase the rates to these customers.

Q. Were these special contracts accepted for filing by the Commission?

A. Yes, they were.

Q. Could these customers physically by-pass Delta's transmission system?

A. Yes. Three of these customers are located near interstate pipelines and could feasibly by-pass Delta's transmission system. The other customer is located near local natural gas production and could also by-pass Delta's transmission system. In fact, this customer actually by-passed Delta during the 1980s. Therefore, all four of these special contract customers could potentially by-pass Delta. Should these customers connect to another interstate pipeline, then Delta would lose the revenue currently being collected from these customers. Delta would thus lose any payments that these customers are making toward the recovery of the utility's fixed costs. The $631,225 in fixed cost recovery from these customers would have to be recovered from other customers if these special contract customers were to by-pass Delta's transmission system. Mr. Brown Kinloch's proposed increase to these special contract customers should therefore be rejected.

Q. Do you have any concerns with the methodology Mr. Brown Kinloch used to develop his proposed customer charges?

A. Yes. In calculating his proposed customer charges he ignores costs that were classified as customer-related in his own cost of service study. For example, he classifies a portion of distribution mains as customer-related in his own cost of service study and allocates these costs on basis of the number of customers. But then he ignores these customer-related costs when he computes his proposed customer charges. The methodology he uses to develop his proposed customer charges is thus inconsistent with his own cost of service study. This approach has been rejected by the Commission in a prior rate case. The Commission specifically rejected this type of methodology in its Order in Case No. 2000-080, an LG&E gas base rate case. The Commission's Order stated as follows:

> [Mr. Brown Kinloch's] cost-of-service study, when presented in a manner similar to LG&E's cost-of-service study, indicates the residential charge should be significantly increased. The AG recommended the Commission rely on the allocation recommendations in the 1989 NARUC Gas Distribution Rate Design Manual. This would result in fewer types of costs being classified as customer-related costs; however, it would also shift costs from the residential class. Such cost shifting is inappropriate given the residential class's consistently low rate of return. (Order in Case No. 2000-080 dated September 27, 2000, pages 75-76.)

Q. Does Mr. Brown Kinloch's own cost of service study support higher customer charges.

A. Yes. If customer-related costs were not reassigned as commodity-related in the computation of his proposed customer charge, Mr. Brown Kinloch's own cost of service study could support a residential customer charge of $14.698. (See page 1 of Seelye Rebuttal Exhibit 3.) This compares to the $12.50 per month customer charge proposed by Delta. Therefore, Mr. Kinloch's own cost of service study supports a customer charge higher than the residential customer charge proposed by Delta.

Q. Does this conclude your testimony?

A. Yes, it does.

Seelye Rebuttal Exhibit 1

Delta Natural Gas Company
Impact on Revenue Requirements of Majoros's Modifications to the Depreciation Rates

Acct No	Description		Impact on Revenue Requirements of Majoros's Modifications
Extending Average Service Lives of Three Accounts			
369	Meas & Reg Stat Equipment	$	(19,504)
376	Distribution Mains		(517,188)
382	Meter & Regulator Installations		(55,296)
Modifying Services Depreciation Rates			
380	Services	$	(98,798)
Failure to Include Net Salvage in Determining Depreciation Rates			
369	Meas & Reg Stat Equipment	$	(4,404)
378	Meas & Reg Stat - General		(4,635)
379	Meas & Reg Stat - City Gate		(1,775)
382	Meas & Reg Installation		(6,590)
383	Houes Reg		8,344
385	Industrial Meter Sets		(3,923)
391	Office Furniture & Equipment		11,780
397	Communication Equipment		19,360
	5-Year Amortization of Net Salvage		11,274
Applying Depreciation Rates to Incorrect Balances			
	Laboratory Equipment	$	5,893
Modifying Storage Depreciation Rates			
350-357	Storage	$	(92,282)
Total Impact of Majoros's Changes		$	(747,744)
Amount Carried Forward to Henkes's Summary (Sch. RJH-5)		$	(747,744)

Seelye Rebuttal Exhibit 2

Adjustment of Gas Revenues to reflect Year-end Customers
Over Average Number of Customers in Test Period
13 Months Ended December 31, 2003

	13 month Average Number of Customers	Customers Served at 12/31/03	Year-End Over (Under) Average (Col. 2 - 1)	Customer Charge	Additional Customer Charge Revenue (Col. 3 x 4)	Weather Normalized Mcf	Average Mcf per Customer (COL. 6 / 1)	Year -End Mcf Adjustment (COL. 7 x 3)	Net Revenue per Mcf Commodity	Additional Revenue Commodity (COL. 8 x 9)	Year-End Revenue Adjustment (COL. 5 + 10)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	33,759	34,100	341	$ 8.00	$ 2,728.00	2,318,102	68.7	23,416	$ 3.6224	$ 84,822.12	$ 87,550.12
Small Non-Residential GS	4,491	4,629	138	$ 17.00	$ 2,346.00	702,702	156.5	21,593		$ 77,050.33	$ 79,396.33
First 200 Mcf						672,486		20,664	$ 3.6224	$ 74,853.27	
Next 800 Mcf						27,406		842	$ 2.4000	$ 2,020.80	
Over 1,000 Mcf						2,810		86	$ 2.0495	$ 176.26	
Large Non-Residential GS - Retail	868	872	4	$ 50.00	$ 200.00	987,090	1,137.2	4,549		$ 13,990.45	$ 14,190.45
First 200 Mcf						672,209		3,098	$ 3.6224	$ 11,222.20	
Next 800 Mcf						270,462		1,246	$ 2.0063	$ 2,499.85	
Next 4,000 Mcf						43,432		200	$ 1.3190	$ 263.80	
Next 5,000 Mcf						987		5	$ 0.9190	$ 4.60	
Over 10,000 Mcf						-		-	$ 0.7190	$ -	
Large Non-Residential GS - Transportation	56	56	-	$ 50.00	$ -	1,103,762	19,710.0	-	$ -	$ -	$ -
Interruptible - Retail	9	9	-	$ 250.00	$ -	51,440	5,715.6	-	$ -	$ -	$ -
Interruptible - Transportation	30	28	(2)	$ 250.00	$ (500.00)	1,267,062	42,235.4	(84,471)		$ (100,661.20)	$ (101,161.20)
						289,088		(19,273)	$ 1.6000	$ (30,836.80)	
						688,108		(45,874)	$ 1.2000	$ (55,048.80)	
						238,590		(15,906)	$ 0.8000	$ (12,724.80)	
						51,276		(3,418)	$ 0.6000	$ (2,050.80)	
Total Retail	39,213	39,694	481		$ 4,774.00	6,430,158		(34,913)		$ 75,201.70	$ 79,975.70
On System Transportation Special	4	4	-		$ -	2,915,837	728,959.3	-	$ -	$ -	$ -
	39,217	39,698	481		$ 4,774.00	9,345,995		(34,913)	$ -	$ 75,201.70	$ 79,975.70

Revenue Adjustment	$ 79,975.70
Expense Adjustment (12.40% of Revenue)	$ 9,916.99
Net Adjustment	$ 70,058.71

Seelye Rebuttal Exhibit 3

Unit Customer Costs from
Brown Kinloch's

Cost of Service Study
12 Months Ended December 31, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Residential (GS)	Large Non-Residential (GS)
Customer Related Costs							
Rate Base				$ 27,354,785	$ 19,724,297	$ 3,614,947	$ 3,335,245
Rate of Return				8.55%	8.55%	8.55%	8.55%
Return				$ 2,338,680	$ 1,686,316	$ 309,058	$ 285,145
Income Taxes				$ 385,629	$ 126,721	$ 79,591	$ 39,213
Operation and Maintenance Expenses				4,161,515	3,128,542	502,558	455,260
Depreciation Expenses				1,104,817	790,599	144,072	140,752
Other Taxes				452,120	330,714	58,078	53,136
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				(136,059)	(90,979)	(17,521)	(17,000)
Total Customer-Related Revenue Requirement				$ 8,306,702	$ 5,971,914	$ 1,075,836	$ 956,505
Less: Misc Service Revenues				(23,752)	(28,043)	(3,759)	(71)
Net Revenue Requirement				$ 8,282,950	$ 5,943,871	$ 1,072,077	$ 956,434
Customer-Months				39,141	33,700	4,476	923
Customer-Related Unit Cost ($/Cust/Mo)				17.635	14.698	19.960	86.352

Unit Customer Costs from
Brown Kinloch's

Cost of Service Study
12 Months Ended December 31, 2003

Description	Ref	Name	Allocation Vector	Interruptible	Special Contracts	Off System Transportation
Customer Related Costs						
Rate Base				$ 602,854	$ 76,852	$ 590
Rate of Return				8.55%	8.55%	8.55%
Return				$ 51,541	$ 6,570	$ 50
Income Taxes				$ 47,570	$ (43)	$ 23
Operation and Maintenance Expenses				62,491	7,842	4,822
Depreciation Expenses				26,062	3,332	-
Other Taxes				8,884	1,128	180
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				(2,874)	(334)	(145)
Total Customer-Related Revenue Requirement				$ 193,674	$ 18,495	$ 4,930
Less: Misc Service Revenues				(6)	-	-
Net Revenue Requirement				$ 193,668	$ 18,495	$ 4,930
Customer-Months				38	4	-
Customer-Related Unit Cost ($/Cust/Mo)				424.710	385.318	