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September 10, 2004

RECEIVED
SEP 10 2004
PUBLIC SERVICE COMMISSION

Hon. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40601

Re: Delta Natural Gas Company, Inc.
Case No. 2004-00067

Dear Ms. O'Donnell:

We enclose for filing an original and ten (10) copies of the Post-Hearing Brief of Delta Natural Gas Company, Inc. in the above-captioned case. In addition, we enclose an extra copy of the Brief that we would like to have file stamped. Thank you for your attention to this matter. Best regards.

Sincerely,

Robert M. Watt, III

Rmw
Cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/encl.)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
SEP 1 0 2004
PUBLIC SERVICE
COMMISSION

In the Matter of:

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

* * * * * * * * * * *

POST-HEARING BRIEF OF DELTA NATURAL GAS COMPANY, INC.

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INTRODUCTION

On April 5, 2004, Delta Natural Gas Company, Inc. ("Delta" or the "Company") requested the Commission's approval of an increase in its base rates in the amount of $4,277,471 on an annual basis. During the course of the proceeding, as a result of information developed during discovery and the correction of schedules submitted with the application, Delta revised its requested increase to $4,510,815 on an annual basis. In addition, Delta requested that the Commission approve a new set of depreciation rates in accordance with Delta's depreciation study submitted with its request for a rate increase. Delta also requested approval of a rider to be added to its bills to collect funds for research and development by the Gas Technology Institute.

Delta's rates have not been adjusted since 1999 when it received its order in its last rate case, No. 99-176. In the meantime, Delta has increased its rate base and issued 600,000 shares of new common stock. While Delta has undertaken measures to keep its costs low, the need for an increase in its base rates can no longer be forestalled and the relief requested herein is fair, just and reasonable.

PROCEDURAL BACKGROUND

On March 1, 2004, Delta gave its notice of intent, pursuant to 807 KAR 5:001, Section 10(2) and 807 KAR 5:011, Section 8(1), to file an application for a general adjustment in its base rates. On April 5, 2004, Delta filed its Notice and Application, together with the Filing Requirements set forth in the Commission's regulations. The direct testimony of Glenn R. Jennings, John F. Hall, John B. Brown, W. Steven Seelye and Martin J. Blake was included as part of the Filing Requirements.

On April 9, 2004, the Attorney General of the Commonwealth of Kentucky ("AG") filed his motion to intervene, which was granted on April 15, 2004. On April 19, 2004, the Lexington-Fayette Urban County Government ("LFUCG") filed its motion to intervene, which was granted on April 23, 2004. The AG and LFUCG are the only intervenors herein.

The Commission entered an order on April 23, 2004, suspending the proposed rates until October 4, 2004, and setting a procedural schedule. The procedural schedule was modified on June 4, 2004, at the request of the AG, to change the hearing date from August 17, 2004, to August 18, 2004.

On March 17, 2004, the Commission issued its first data request to Delta, to which a response was filed on April 19, 2004. On May 11, 2004, the Commission issued its second data request to Delta. On May 14, 2004, the AG filed his first data request to Delta. Delta submitted responses to the Commission's second data request and to the AG's first data request on May 27, 2004. On June 9, 2004, the Commission issued its third data request to Delta and the AG filed his supplemental data request to Delta. Responses were filed by Delta on June 22, 2004. LFUCG did not submit any data requests to Delta.

On July 2, 2004, the AG filed the direct testimony of his witnesses: Robert J. Henkes, Michael J. Majoros, Jr., Charles W. King and David H. Brown Kinloch. On July 16, 2004, the AG filed the corrected direct testimony of Charles W. King. LFUCG did not file any testimony or other evidence.

On July 16, 2004, the Commission and Delta submitted data requests to the AG. Responses were filed on July 29, 2004.

Delta filed the rebuttal testimony of Messrs. Jennings, Hall, Brown, Seelye and Blake on August 9, 2004. On August 17, 2004, the AG filed a motion to strike the rebuttal testimony of Messrs. Brown and Seelye. Delta filed its response to the motion on August 18, 2004, at the outset of the hearing. In addition, Delta filed its motion for deviation from the publication rule due to the failure of two newspapers to publish notice of the hearing and Delta's mailing of the notice to all of its active customers in the affected counties. The Commission granted the motion for deviation. The Commission heard oral arguments from counsel on the motion to strike rebuttal testimony and denied the motion as it related to Mr. Brown's rebuttal testimony, but granted the motion insofar as it related to Exhibit 2 of Mr. Seelye's rebuttal testimony.

The hearing proceeded on August 18, 2004, and was concluded that evening. The Commission, Delta, the AG and LFUCG were represented by counsel at the hearing and all witnesses appeared and were cross-examined. On August 23, 2004, the AG filed his response to the Commission's hearing data requests. On August 30, 2004, Delta filed its responses to the Commission's and the AG's hearing data requests.

RATE BASE

Delta proposed the use of net original cost rate base as of the end of the test year, December 31, 2003, of $111,071,658 in this proceeding.[1] The net original cost rate base was later modified to reflect changes in cash working capital resulting from changes in operation and maintenance expense, so that Delta's proposed rate base is $111,078,214.[2] The methodology utilized by Delta is consistent with Commission policy in that it utilizes

[1] Tab 27 of the Filing Requirements, Schedule 7.
[2] Hall Rebuttal Testimony, Application Tab 27, Schedule 7.

actual test year information, with adjustments to establish the appropriate rate base upon which to calculate the revenue requirement. The rate base is presented by John F. Hall, Delta's Vice President-Finance, Secretary and Treasurer, in the same format that Delta has used in several prior rate cases.[3] There is little dispute by the AG with the rate base methodology set forth in the Filing Requirements and in Mr. Hall's rebuttal testimony. The matters of dispute are set forth below.

Cash Working Capital Requirement.

The AG's witness, Robert J. Henkes, does not agree with the Commission's customary methodology of calculating the cash working capital requirement by taking 1/8 of the pro forma operations and maintenance expense (net of gas supply expense), instead preferring the use of a lead/lag study.[4] Nevertheless, Mr. Henkes utilizes the "modified 1/8th formula" in determining the cash working capital requirement because of the Commission's consistent use of this methodology.[5] Delta also utilizes the "modified 1/8th formula" to determine cash working capital requirement.[6] The only difference in the two proposals results from the differences in pro forma operations and maintenance expense developed by Delta and the AG.

Prepayments.

Delta proposes the use of the customary 13 month average of prepayments to determine the $351,876 pro forma amount in rate base.[7] The AG has no dispute with the methodology utilized, but Mr. Henkes testified that the inclusion of $39,440 for

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[3] Hall Direct Testimony at 3, 5; Hall Rebuttal Testimony at 1.
[4] Henkes Direct Testimony at 6-7.
[5] *Id.*
[6] Tab 27 of the Filing Requirements, Schedule 7; Hall Rebuttal Testimony, Application Tab 27, Schedule 7.
[7] *Id.*

prepayments associated with the Commission's annual assessment is improper.[8] Delta acknowledges that the Commission has excluded the assessment amount from prepayments in rate base in some recent rate orders, but it did not do so in Delta's last two rate orders.[9] It is appropriate to include the assessment in prepayments because, in fact, it is a prepayment. As the Commission knows, the assessment is made each year pursuant to KRS 278.130 and utilities are notified of the amount on or before July 1 of each year. The invoices received by utilities indicate that they are to be paid prior to July 1 and the assessments are collected "[f]or the purpose of maintaining the commission, including the payment of salaries and all other expenses, and the cost of regulation of the utilities subject to its jurisdiction."[10] The assessment cannot be used to pay such expenses unless it is collected prior to the period to which it applies. Thus, it must be a prepayment. Therefore, Delta urges the Commission to reconsider its position regarding prepayments and to include the assessment in prepayments.

Accumulated Depreciation Reserve Adjustment.

Delta proposes a depreciation adjustment of $145,431 to increase rate base to reflect the implementation of new depreciation rates developed by W. Steven Seelye.[11] The AG does not agree with Mr. Seelye's depreciation rates and proposes his own depreciation rates developed by Michael J. Majoros, Jr.[12] The use of Mr. Majoros's depreciation rates results in a depreciation adjustment of $759,744 to rate base.[13] Delta agrees that the depreciation adjustment should conform to the depreciation rates adopted,

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[8] Henkes Direct Testimony at 7-8.
[9] *In the Matter of: An Adjustment of General Rates of Delta Natural Gas Company, Inc.*, Case No. 97-066, Order dated December 8, 1997, at 4; *In the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc.*, Case No. 99-176, Order dated December 27, 1999, at 6-7.
[10] KRS 278.130.
[11] Tab 27 of Filing Requirements, Tab 5; Hall Direct Testimony at 5.
[12] Mr. Majoros's depreciation rates will be discussed *infra*.
[13] Henkes Direct Testimony at 8, Sch. RJH-3.

but believes that the rates proposed by Mr. Seelye should be used rather than those proposed by Mr. Majoros.

CAPITAL STRUCTURE

Delta's capital structure was originally set forth at Schedule 9 of Tab 27 of the Filing Requirements. During the course of discovery, Delta became aware of an error in the original statement of the capital structure. In addition, the orders in the recent rate cases of Louisville Gas and Electric Company and Kentucky Utilities Company directed the treatment of Minimum Pension Liability different from that proposed by Delta.[14] Accordingly, in responses to data requests and in the rebuttal testimony of Delta's Controller, John B. Brown, Delta described the correction of the error and the change occasioned by the proper treatment of Minimum Pension Liability.

In its original statement of its capital structure, Delta set forth the equity component, including subsidiaries, as $44,030,321.[15] This amount should not be used here because it is the net equity for GAAP financial reporting purposes rather than the amount that is appropriate for rate making purposes.[16] The correction was explained and reconciled in response to data request AG 1-1.

The Minimum Pension Liability issue was addressed in response to data request AG 2-11. There, Delta submitted a letter from the Federal Energy Regulatory Commission dated March 29, 2004, in Docket No. A104-2-000, which set forth the

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[14] *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order dated June 30, 2004, at 18-22; *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order of June 30, 2004, at 16-20.

[15] Tab 27 of the Filing Requirements, Schedule 9.

[16] Brown Rebuttal Testimony at 4.

proper treatment of Minimum Pension Liability. The FERC letter and the orders of June 30, 2004, in the LG&E and KU rate cases both provide that the equity balance should be restated to include "Accumulated Other Comprehensive Income" caused by Minimum Pension Liability. These revisions are detailed in the rebuttal testimony of Mr. Brown.[17] The restatement of the equity component to reflect properly the Minimum Pension Liability results in the addition of $2,050,636 to equity.[18]

While the AG did not address the Minimum Pension Liability issue in any of his direct testimony, Mr. Henkes stated his disagreement with the restatement of the equity component of the capital structure to include Minimum Pension Liability during the hearing.[19] The AG also disagreed with the inclusion of Minimum Pension Liability in the LG&E and KU rate cases, but his position was specifically rejected by the Commission there.[20] The same treatment is, therefore, appropriate here.

The result of the two changes is that the equity component of Delta's capital structure should be $46,080,957, including subsidiaries, and $44,915,682, excluding subsidiaries.[21] The revised schedule setting forth the capital structure is set forth in the spreadsheet entitled "Application, Tab 27, Schedule 9" attached to Mr. Hall's rebuttal testimony. As revised the capital structure that should be used for rate making purposes herein is as follows:

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[17] Brown Rebuttal Testimony at 4-5.
[18] Brown Rebuttal Testimony at 4.
[19] Transcript of Evidence ("TE") at 242-243.
[20] Case No. 2003-00433, Order dated June 30, 2004, at 21-22; Case No. 2003-00434, Order dated June 30, 2004, at 19-20.
[21] *Id.*

	Per Books Consolidated at 12/31/03	Eliminate Subs	Adjusted Capital Structure	Ratios
Equity	$ 46,080,957	$ (1,165,275)	$ 44,915,682	38.24%
L/T Debt	54,824,000		54,824,000	46.68%
S/T Debt	17,707,889		17,707,889	15.08%
Total	$ 118,612,846	$ (1,165,275)	$ 117,447,571	100.00%

OPERATING INCOME

Delta has approached the determination of operating income for rate making purposes with primary attention to the actual test year experience with adjustments for known and measurable changes in accordance with 807 KAR 5:001, Section 10(a). The information relating to the Company's operating income is set forth in the schedules at Tab 27 of the Filing Requirements and adopted by Mr. Hall in his direct testimony.[22] During the course of discovery, Delta became aware of certain revisions that should be made to these schedules. Those revisions were made and are set forth in the attachments to Mr. Hall's rebuttal testimony. After taking into account the adjustments set forth in the schedules at Tab 27 of the Filing Requirements and attached to Mr. Hall's rebuttal testimony, Mr. Hall determined that the test year adjusted net operating income was $6,841,663.[23] As was the case with his determination of rate base, many of Mr. Hall's operating income determinations have not been contested by the AG. The matters of dispute are discussed below.

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[22] Hall Direct Testimony at 4-6.
[23] Hall Rebuttal Testimony, Application Tab 42, page 3 of 4.

Payroll Expenses.

In its original filing, Delta proposed an adjustment to increase test year payroll expenses to reflect the salary and wage increase that occurred during the test year of $120,697 less an employee bonus that was awarded during the test year in the amount of $403,865.[24] During the course of discovery, Delta discovered that the bonus exclusion was incorrectly calculated because the portion of it that should be allocated to Delta's subsidiaries was not considered. Therefore, Mr. Hall filed a revised work paper reflecting the proper allocation of the bonus with his rebuttal testimony.[25] The result is that the bonus excluded should be $317,865 and the total payroll adjustment should be a reduction of $197,168.[26] The AG agrees with Delta's treatment of the bonus.[27] The AG does not take issue with the other treatment of payroll expense.

Rate Case Expense Amortization.

Delta proposes an adjustment to amortize actual rate case expense over three years, which is consistent with the treatment of this issue in Delta's last rate case.[28] It is also consistent with the treatment of rate case expense in several recent rate cases, including those involving LG&E, KU and The Union Light, Heat and Power Company.[29] The AG, however, proposes the amortization of rate case expense over four years.[30] The AG's argument is no more appropriate here than it was in other cases in which he

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[24] Tab 27 of Filing Requirements, Hall WP 4.1.
[25] Hall Rebuttal Testimony, Application Tab 27, Hall WP 4.1.
[26] *Id.*
[27] Henkes Direct Testimony at 16.
[28] Hall Direct Testimony at 5.
[29] *In the Matter of: The Application of Louisville Gas and Electric Company to Adjust its Gas Rates, Etc.*, Case No. 2000-080, Order dated September 27, 2000, at 39-40; *In the Matter of: Adjustment of Gas Rates of The Union Light, Heat and Power Company*, Case No. 2001-00092, Order of January 31, 2002, at 39; *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Order dated June 30, 2004 at 40; *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order dated June 30, 2004, at 36.
[30] Henkes Direct Testimony at 19-20.

proposed amortizations longer than three years. The proposed three year amortization of actual rate case expenses should be approved.

Customer Deposits.

Delta originally included interest on customer deposits in operating expenses. During the course of responding to data requests PSC 2-8 and 3-5, Delta realized that its treatment of this issue was not consistent with the Commission's treatment of this issue in Delta's last rate case. In addition, Mr. Henkes testified that the appropriate treatment is to exclude interest on customer deposits from operating expenses.[31] Therefore, in his rebuttal testimony, Mr. Hall revised his WP 4.1 to exclude interest on customer deposits.[32] During the hearing Mr. Henkes stated that he agreed with Delta's treatment of this issue.[33] Thus, the Commission should treat customer deposits in the same fashion as Mr. Hall did in his rebuttal testimony.

401(k) Expense.

Delta originally proposed the recovery of the test year 401(k) expenses in the amount of $132,894. During the course of discovery, Delta discovered that the expense was understated for the test year and that it should have been $156,727. Delta stated that the reason for the understatement was the timing of invoices received.[34] Mr. Henkes takes no exception with the restatement of the test year 401(k) expense.[35] Therefore, the 401(k) expense should be included at $156,727.

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[31] Henkes Direct Testimony at 15-16.
[32] Hall Rebuttal Testimony, Application Tab 27, Hall WP 4.1.
[33] TE at 213-214.
[34] See Responses to PSC 2-25(aa) and AG 1-9.
[35] Henkes Direct Testimony at 18-19.

Miscellaneous Expenses.

Delta proposes an adjustment in the total amount of $59,151 to exclude expenses relating to lobbying, public and community relations and marketing pursuant to 807 KAR 5:016 and its understanding of the treatment of these expenses in Delta's last rate cases.[36] While the AG agreed that these items should be excluded from operating expenses, he argued that an additional $87,343 of miscellaneous expenses should be removed from operating expenses.[37] Delta's proposed adjustment is appropriate and the additional expense removal proposed by the AG should be rejected.

Mr. Henkes proposes to remove expenses relating to several items that are legitimate business expenses. While some of these types of expenses have been excluded for rate making purposes in some prior rate cases, Delta urges the Commission to reconsider these issues here. For example, Mr. Henkes recommends removal of 27.09% of Delta's American Gas Association dues because he believes that that portion of the dues pays for public affairs and advertising.[38] During the hearing, Mr. Henkes took the position that all of the public affairs expense was devoted to lobbying.[39] However, the AGA takes the position that less than 2% of Delta's dues were allocated to lobbying as defined in federal regulations.[40] Further, Delta's President and CEO, Glenn R. Jennings, testified in his rebuttal testimony and at the hearing at length about the importance of trade associations, like the AGA, to Delta because of its provision of training, tracking of industry changes and the ability to have input into the legislative and regulatory

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[36] Tab 27 of Filing Requirements, Schedule 4 and Hall WP-4.3.
[37] Henkes Direct Testimony at 26-29.
[38] Henkes Direct Testimony at 27, Sch. RJH-13.
[39] TE at 226.
[40] Response to AG 1-39(c).

processes.[41] Mr. Jennings believes fervently that expenses related to the AGA should be recovered in full because of the importance of the association to Delta and other small utilities. Delta respectfully requests the Commission to take a fresh look at this issue when deciding what portion of the AGA dues should be included for rate making purposes.

Mr. Henkes also recommends the exclusion of expenses related to incentive payments.[42] Mr. Henkes stated in his testimony that Delta agreed that $44,200 of these expenses should have been excluded.[43] While it is true that Delta agreed in response to a data request that incentive payment expenses should be removed, it did so because of its understanding that similar expenses had been excluded in some past Commission decisions. Mr. Jennings stated in his rebuttal testimony and during the hearing that he believes such expenses are valid business expenses that should be recovered.[44] These expenses have helped Delta increase its customer base and the revenues from such customers are included for rate making purposes. It is only fair to include the expenses for ratemaking purposes. Delta believes that the Commission should re-examine this issue and should include these expenses for ratemaking purposes.

Mr. Henkes recommends that expenses relating to employee gifts, award banquets, parties and other social events should be removed.[45] While Delta is aware that in prior rate cases some expenses of this character have been excluded for ratemaking purposes, Delta urges the Commission to revisit this issue. All of these expenses are made to improve employee morale and to enhance efficiency, safety and employee

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[41] Jennings Rebuttal Testimony at 4; TE at 39-40.
[42] Henkes Direct Testimony at 27.
[43] *Id.*
[44] Jennings Rebuttal Testimony at 4; TE at 27-28.
[45] Henkes Direst Testimony at 27-28.

retention.[46] These expenses are considered legitimate business expenses in the competitive world and should be considered legitimate expenses for rate making purposes in the regulated world.

Mr. Henkes recommends exclusion of expenses related to economic development.[47] Again, Delta is aware that economic development expenses have been excluded in some prior rate cases, but believes that the issue should be revisited. Economic development is important to Delta's customers, as well as to other persons in Delta's service areas. As Mr. Jennings testified:

> These efforts assist in adding new customers and in adding new sales loads in our service area. These sales from such customers are included in Delta's revenues in this test year and thus are taken into account in setting rates for all customers. This helps to keep rates lower to all customers by spreading our overhead over a larger sales and customer base. These expenses also assist in the economic development of our service area by strengthening the economy and helping provide jobs. This certainly helps all of our customers and our service area.[48]

Therefore, Delta requests the Commission to take a fresh look at this issue. In evaluating the treatment of Miscellaneous Expenses, the Commission should review the discussions of these issues by courts in the past. In 1935, Mr. Justice Cardozo, speaking for the United States Supreme Court, made the following observation:

> Good faith is to be presumed on the part of the managers of a business. (Citations omitted) In the absence of a showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay. (Citations omitted) The suggestion is made that there is no evidence of competition. We take judicial notice of the fact that gas is in competition with other forms of fuel, such as oil and electricity. A business never stands

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[46] Jennings Rebuttal Testimony at 4; TE at 41.
[47] Henkes Direct Testimony at 28.
[48] Jennings Rebuttal Testimony at 4.

> still. It either grows or decays. Within the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes as for others . (Citation omitted) When a business disintegrates, there is damage to the stockholders, but damage also to the customers in the cost or quality of service.[49]

Later the Vermont Supreme Court made the following observation:

> The function of a public service commission is that of control and not of management, and regulation should not obtrude itself into the place of management. (Citation omitted) This rule is recognized in all of the cases. This matter of salaries and advertising expense calls for the exercise of judgment on the part of the management of the company. Good faith on its part is to be presumed. Although these expenses should be scrutinized with care by the commission they should not be disallowed or reduced unless it clearly appears that they are excessive or unwarranted or incurred in bad faith. (Citation omitted)[50]

An examination of all the evidence in this proceeding leads to no suggestion that the Miscellaneous Expenses incurred by Delta during the test year were excessive, unwarranted or incurred in bad faith. The guidance of the United States Supreme Court and the Vermont Supreme Court is persuasive that such expenses should be included for rate making purposes.

Year-End Adjustment.

While Mr. Henkes propose two alternative types of "customer growth" adjustment,[51] such adjustment, also called "year-end" adjustment, is not warranted. Delta did not propose to adjust test-year revenues and expenses to reflect the number of customers served as of the end of the test year. As explained in the direct and rebuttal testimony of William Steven Seelye, it is not appropriate to make a year-end adjustment

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[49] *West Ohio Gas Co. v. Public Utilities Commission*, 294 U.S. 63, 72, L. Ed. 761, 55 S. Ct. 316 (1935).

[50] *Petition of New England Tel. & Tel. Co.*, 115 Vt. 494, 66 A.2d 135, 145 (1949).

[51] Henkes Direct Testimony at 9-14.

because there has been a reduction in the number of customers served by Delta from the beginning of the test year to the end of the test year. From December 2002 to December 2003, Delta experienced a reduction of 420 customers.[52] A year-end adjustment is typically made to account for customer growth during the test year. However, Delta did not experience any customer growth. Because of the seasonal pattern in customer connections and disconnections, the number of customers served by a gas utility will be close to its highest during the month of December. In the case of Delta, because the test year ends in December, the standard year-end adjustment would simply account for seasonal variations in the number of customers. Consequently, a year-end adjustment for Delta would imply that there was customer growth when in fact there was none.

Mr. Henkes's application of the standard year-end adjustment methodology contains errors. He presented two methodologies for computing a year-end adjustment. In his exhibit RJH-6A he used the more traditional approach which compares the number of customers at the end of the test year to the 13-month average. In RJH-6B he develops his adjustment by applying a 5-year compound growth rate to the 13 month average customers. The methodology used in RJH-6B was rejected by the Commission in Louisville Gas and Electric Company's recent rate case.[53]

The methodology used by Mr. Henkes to calculate the year-end adjustment in RJH-6A contains several errors, the most important of which is that he failed to recognize that there was an average reduction of two interruptible transportation customers at the end of the test year compared to the 13-month average. Contrary to what was stated in the AG's Motion to Strike Seelye Rebuttal Exhibit 2, all of the information necessary for

[52] Seelye Direct Testimony at 23.
[53] Case No. 2003-00433, Order dated June 30, 2004, at 26-28.

Mr. Henkes to perform the year-end adjustment properly was contained in Seelye Exhibit 8 and Seelye Exhibit 9. Based on information contained in the record in this proceeding, it is obvious that Mr. Henkes overstated the year-end revenue adjustment by $106,577. There were 28 interruptible transportation customers as of December 31, 2003.[54] However, there were 30 interruptible transportation customers on average during the 13-month period ended December 31, 2003.[55] The average revenue per customer for interruptible transportation customers is $53,288.60.[56] Therefore, by ignoring the reduction in the number of interruptible transportation customers, Mr. Henkes overstated the year-end revenue adjustment by $106,577.20 ($53,288.60 x 2 customers). Hence, if Mr. Henkes's RJH-6A is used as a basis for a year-end adjustment, the revenue should be reduced by $106,577.20.

The Commission should not make a year-end adjustment relating to customer growth. If it does, however, it should ensure that the adjustment does not contain the errors made by Mr. Henkes in his proposed adjustment.

Directors' Fees and Expenses.

Delta proposed no adjustment to the test year level of directors' fees and expenses for the reason that it is representative of the level of such fees and expenses on a going forward basis.[57] The AG's witness, Mr. Henkes, however, proposes the removal of

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[54] Seelye Exhibit 8.

[55] As shown on Seelye Exhibit 9, page 4, there were 355 customer-months during the 12 months ended December 31, 2003. There were 31 customers served in December 2002. Therefore, there were 386 customer months (355 + 31) for the 13-month period ended December 31, 2003. Thus, on average, there were 30 customers (386 ÷ 13 months) served during the 13-month period ended December 31, 2003.

[56] As shown on Seelye Exhibit 9, page 4, there were $1,598,658 in test-year revenue for interruptible transportation customers. Based on 355 customer-months (*id.*), the average revenue per customer is $53,288.60 ($1,598,658 ÷ (355 ÷ 12)).

[57] TE at 36.

$51,440 of directors' bonuses and $686 for a directors' Christmas dinner and gifts.[58] His rationale is that the bonus is a nonrecurring expense and the dinner expense does not produce any material benefit to the ratepayers.[59]

While the particular bonus may be a nonrecurring expense, the total level of directors' fees, including the bonus, is the minimum level that will be experienced on a going forward basis.[60] The level of directors' fees has increased over recent years because of the need to attract highly competent directors, particularly in view of the Company's need to comply with the Sarbanes-Oxley Act of 2002. The exposure of directors of publicly traded companies to liabilities has increased significantly in the wake of the Enron scandal and other similar problems with corporate governance. Delta researched the level of directors' compensation paid by other publicly traded companies and found that its level of compensation is very reasonable in comparison with other companies.[61] Thus, the payment of higher compensation for directors is necessary to attract the high quality directors Delta is fortunate to have.[62] The bonuses paid during the test year did not cause the level of compensation to make a one time jump above a reasonable level. Instead, it only caused it to approach a reasonable level. This situation is contrasted with the employee bonuses, which Delta voluntarily removed from test year expenses because it was deemed to be nonrecurring and the level of compensation without the bonuses was reasonable.

Actions taken after the end of the test year demonstrate that the test year level of directors' fees is representative of the ongoing level of such fees. Effective March 1,

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[58] Henkes Direct Testimony at 22-23.
[59] *Id.*
[60] Jennings Rebuttal Testimony at 2-3; TE at 36-37.
[61] TE at 31-32.
[62] *Id.*

2004, Delta's directors' fees were increased to an annualized level of $205,200.[63] On August 26, 2004, Delta's Board passed a resolution directing that the directors receive additional cash compensation equal to the value of 100 shares of Delta's common stock at the closing price on August 26, 2004, or $2,638.[64] The total additional compensation for Delta's ten directors is $26,380. This compares closely to the $22,820 of stock compensation the directors received during the test year.[65] Therefore, taking into account the 2004 actions regarding directors' compensation, the level of compensation will be the sum of $205,200 and $26,380 or $231,580. The test year level of directors' fees and expenses was $225,369, including the bonuses. It is, accordingly, respectfully submitted that the bonus portion of this expense should not be removed from operating expenses for rate making purposes.

As to the expense for the Christmas dinner and gifts, Delta believes that this expense is a necessary expense to help it retain high quality directors, like the employee awards dinners and the like. Mr. Jennings offered his view of the recoverability of this expense as follows:

> [M]y view is that those things are valid business expenses of the company and something that's necessary from time to time. We don't do that very often, but occasionally gather our Board together, and there will be some business discussions and they'll have a dinner together, and we believe that's an appropriate thing to do, and, if we didn't think it was appropriate, we wouldn't do it at all, and, if it is appropriate, we think it ought to be reflected in our rates.[66]

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[63] Jennings Rebuttal Testimony at 2.
[64] Response to Staff Hearing Data Request 1.
[65] Jennings Rebuttal Testimony at 2.
[66] TE at 37-38.

This expense certainly passes the test enunciated by the Vermont Supreme Court, above, in that it is not excessive, unwarranted or incurred in bad faith. Thus, even if this kind of expense has been removed for rate making purposes in some prior cases, Delta urges the Commission to reconsider its position here.

Outside Accounting Expense.

Because the level of outside accounting expenses is reasonable on a going forward basis, Delta proposed no adjustment to this item. Mr. Henkes, however, proposes the removal of the nonrecurring expense portion of such expenses in the amount $163,328.[67] It is not grounds to remove an expense for rate making purposes simply because it is nonrecurring. Such treatment of nonrecurring expenses would be contrary to established law regarding the exclusion of expenses from base rates.

It is well established that a utility should be allowed to recover an expense, except in the rare circumstance when it is imprudently incurred. If the inclusion of a nonrecurring expense causes the level of expense in a given account to exceed the ongoing level of that account, the fact that the expense is nonrecurring may indicate that a different kind of recovery is appropriate; namely the amortization of the expense over a period of time. However, the fact that an expense is simply nonrecurring does not support the denial of recovery of such costs in base rates.

Direction regarding the recovery of utility expenses has been provided by the United States Supreme Court, which quoted from a decision of the Illinois Supreme Court[68] as follows:

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[67] Henkes Direct Testimony at 25.

[68] *State Public Utilities Commission ex rel. Springfield v. Springfield Gas & Electric Co.*, 291 Ill. 209, 234, 125 N.E. 891, 901 (1919).

> The Commission is not the financial manager of the corporation and it is not empowered to substitute its judgment for that of the directors of the corporation; nor can it ignore items charged by the utility as operating expenses unless there is an abuse of discretion in that regard by the corporate officers.[69]

Furthermore, in a concurring opinion in the same case, Mr. Justice Brandeis stated:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.[70]

In 1935, the Supreme Court held that good faith is presumed on the part of the utility absent a showing of inefficiency or improvidence.[71] Based on this guidance from the United States Supreme Court, the concepts of "wasteful," "dishonest," "extravagant," "unnecessary," "inefficient" and "improvident" would seem to be good concepts to apply in determining whether a utility should be denied recovery of expenses that it has incurred.

Along the same lines, Professor Bonbright defines a prudent cost as "the original historical cost minus any fraudulent, unwise, or extravagant outlays that should not be a burden on ratepayers."[72]

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[69] *State of Missouri ex rel. Southwestern Bell Telephone Company v. Public Service Commission of Missouri, et al.*, 262 U.S. 276, 289, 43 S.Ct. 544, 67 L.Ed. 791 (1923).

[70] *Id.* at 289, n. 1.

[71] *West Ohio Gas Co. v. Public Utilities Commission of Ohio,* 294 U.S. 63, 72, 79 L.Ed. 761, 55 S.Ct. 316 (1935).

[72] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, *Principles of Public Utility Rates* at 223 (Public Utility Reports, Inc., 1988).

The proper approach for deciding whether utility expenses should be recovered from customers is effectively summarized in an Opinion filed on September 23, 1997, by the Court of Appeals of Missouri, Western District. There, the Court stated that the Missouri Public Service Commission has employed the following approach to determine whether a utility's costs meet the just and reasonable statutory requirement, and thus, should be recovered from customers:

> If a utility's costs satisfy the prudence standard, the utility is entitled to recover those costs from its customers. The PSC has defined its prudence standard as follows:
>
> > A utility's costs are presumed to be prudently incurred. However, the presumption does not survive a showing of inefficiency or improvidence. Where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. (Citations omitted)[73]

It is important to note that in none of the foregoing authorities is "nonrecurring" on the list of adjectives describing costs that utilities should not be allowed to recover.

Here, there can be no doubt about the prudence of the outside accounting expense; it was made to comply with federal legislation, the Sarbanes-Oxley Act of 2002. Further, the level of outside accounting expenses necessary to comply with Sarbanes-Oxley will remain at the test year level, less $83,748, even though the identity of the particular expenses may change.[74] Both Mr. Jennings and Mr. Brown described at length the numerous and burdensome activities that must take place for Delta to comply with

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[73] *State of Missouri ex rel. Associated Natural Gas Company v. Public Service Commission of the State of Missouri*, 954 S.W.2d 520, 528 (Mo. App. 1997).
[74] Brown Rebuttal Testimony at 2.

Sarbanes-Oxley.[75] Since Delta is a relatively small publicly traded company, its in-house staff cannot perform all of the activities necessary and heavy reliance must be placed on outside accounting services. The level of test year outside accounting expense, less $83,748, should be included for rate making purposes.

The fact that a cost is nonrecurring may result in a different kind of recovery; namely amortization over a period of time to prevent customers from paying the full amount of the nonrecurring cost each year. Therefore, the $83,748 that Delta identified should be amortized over three years. If the Commission decides that the entire $163,328 identified by Mr. Henkes should be removed from outside expense, then it should be amortized over three years.

If a prudently incurred, nonrecurring expense were amortized over the period of time between rate cases, usually three years, the utility would recover the prudently incurred expense, while customers would not bear the full amount of the expense in each year. During cross examination, Mr. Henkes indicated that such amortized recovery of nonrecurring expenses would be appropriate for large expenses such as remediation expense.[76] However, he recommended that the nonrecurring expenses that Delta incurred during the test year that he identified should be disallowed and not recovered through base rates.[77] It is illogical and not supported by law for large nonrecurring expenses to be amortized and recovered while smaller nonrecurring expenses are disallowed.

In the 1990 rate case of LG&E, this Commission dealt with the issue of non-recurring expenses. In its initial Order in that proceeding, the Commission disallowed $9.4 million in expenses associated with a 1989 workforce downsizing based on the

[75] TE at 43-47, 91-97, 112-127, 130-133.
[76] TE at 222.
[77] TE at 223-224.

argument that it was a non-recurring expense.[78] LG&E requested a rehearing on this issue arguing that such treatment of non-recurring expenses was improper. On rehearing, the Commission agreed with LG&E and allowed the recovery of a portion of this nonrecurring downsizing cost by amortizing it over a three year period.[79] However, the Commission did not allow the unamortized balance of the downsizing costs to be included in rate base which denied LG&E a return on the unamortized amount of the nonrecurring expense. A similar treatment would be appropriate in this case with nonrecurring expenses of $83,748 being amortized over a three year period and included in rates. Delta is not requesting a return on the unamortized balance of these nonrecurring expenses. If the Commission decides that the entire $163,328 should be removed from test year expense, then that amount should be amortized over three years.

Computer Expense Adjustment.

Delta proposed that outside services relating to computer expenses (Account 1.923.05) be recovered at the test year level, with no adjustment.[80] Mr. Henkes recommends removal of $42,404 from this account for imaging expenses that are nonrecurring.[81]

As discussed above, the fact that an expense is nonrecurring is not a proper reason to disallow it for rate making purposes. Mr. Henkes identified no other reason for his proposed disallowance. In addition, Mr. Brown demonstrated beyond peradventure that the level of expense for the test year in this account is representative of the level on a

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[78] *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 90-158, Order dated December 21, 1990, at 28-29.
[79] *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 90-158, Order dated September 30, 1991, at 14.
[80] Brown Rebuttal Testimony at 2-3.
[81] Henkes Direct at 26.

going forward basis.[82] Therefore, computer expense should be included at the test year level. If the Commission were to decide that the $42,404 identified by Mr. Henkes should be removed from operating expenses for rate making purposes, then it should be amortized over three years like the accounting expense discussed above.

Depreciation Expense.

A pro-forma adjustment was made by Delta to reflect annualized depreciation expenses under the proposed depreciation rates as applied to plant in service as of the end of the test year. The proposed rates were based on a depreciation study conducted by The Prime Group, LLC, which was included as Exhibit 7 of the direct testimony of Mr. Seelye. As explained in Exhibit 7, "The purpose of performing a depreciation study is to insure that the depreciation expenses recorded by the utility and included in the cost of service represents a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over the estimated useful life of the assets." The depreciation accrual rates were calculated using the average service life depreciation procedure, the straight line method, and the remaining life basis. The work papers, including the computer model used to perform the depreciation study, were provided in response to PSC 2-17. The depreciation model used to develop Delta's depreciation rates was thus available to be scrutinized, critiqued and validated.

The depreciation study indicated that many of Delta's current depreciation accrual rates should be lowered. The proposed depreciation rates were applied to net plant

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[82] Brown Rebuttal Testimony at 2-3.

balances as of December 31, 2003, to determine the pro-forma level of expenses, resulting in a decrease in depreciation expenses of $145,431.[83]

The AG's recommended service lives are without probative value and should be ignored. Michael J. Majoros, Jr., who submitted depreciation testimony on behalf of the AG, proposed longer service lives, and thus lower depreciation rates, for three plant accounts – Account 369 – Measuring and Regulation Station Equipment, Account 376 – Distribution Mains, and Account 382 – Meter and Regulator Installations. Mr. Majoros testified that his proposed service lives were determined using the Simulated Plant Records (SPR) method.[84] In Question No. 6 of Delta's data request to the AG, Mr. Majoros was asked to provide a copy of his SPR model. However, in violation of the Commission's regulations, Mr. Majoros refused to provide a copy of the SPR model on the grounds that it is proprietary. Section (7)(a) of 807 KAR 5:001 states as follows:

> No party to any proceeding before the commission shall fail to respond to discovery by the commission or its staff or any other party to the proceeding on grounds of confidentiality. If any party responding to discovery requests seeks to have a portion or all of the response held confidential by the commission, it shall follow the procedures for petitioning for confidentiality contained in this administrative regulation. Any party's response to discovery requests shall be served upon all parties with only those portions for which confidential treatment is sought obscured.

During the hearing, Mr. Majoros was unapologetic and adamant in his refusal to provide a copy of the model. Without being provided an opportunity to review the calculations performed, it is simply impossible to verify the results of his SPR analysis,

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[83] Tab 27 of the Filing Requirements, Schedule 5.
[84] Majoros Direct Testimony at 20. See also Mr. Majoros's response to Question 10 of Delta's data request to the AG.

as freely admitted by Mr. Majoros. When asked if he could verify the figures shown on pages 3, 10, and 17 of Exhibit ____(MJM-1), he indicated that he could not perform those calculations[85] and that Delta and the Commission would simply have to accept the figures on his word.[86] When asked how the Commission and the parties would know whether the figures were calculated correctly, Mr. Majoros responded: "Because I say it is. I put my hand on the Bible and I say it was, . . ."[87] Furthermore, Mr. Majoros was unable to describe with any specificity the methodology used to compute the survivor curve values in his SPR model. Specifically, he had no understanding of the numerical integration technique used to compute the survivor curve values in his SPR model.[88] By his own admission, Mr. Majoros is relying on a model he did not develop[89] and does not fully understand. Without the Commission and parties having the opportunity to inspect the model then it is impossible to determine whether it was free of computational errors or whether the figures purportedly produced by the model were simply fabricated.[90]

To say the least, it is highly unusual for parties in rate cases to adamantly refuse to provide information requested in data requests solely on confidentiality grounds. Delta and other utilities routinely provide working copies of proprietary computer models pursuant to confidentiality orders and agreements. Without being able to independently verify that the computations of Mr. Majoros's computer model have been performed

[85] Mr. Majoros's attempt to "correct" this testimony that he gave on cross-examination after he left the witness stand should not be condoned. TE at 286-289. It clearly would amount to improper surrebuttal or an improper attempt to impeach his own sworn testimony given earlier.
[86] TE at 260.
[87] *Id.*
[88] T.E. at 256.
[89] T.E. at 252. Mr. Majoros indicated that the model was originally developed by Dr. Ronald White.
[90] Given Mr. Majoros's claim that he is a member of two certified public accounting associations on his resume and his admission during the hearing that he has not been a certified public accountant since the late 1980s, the Commission should carefully consider Mr. Majoros's credibility on those matters he asks it to take on his word. Compare Majoros Direct Testimony, Appendix A versus TE at 249.

correctly, it is impossible to verify the information shown on pages 3, 10, and 17 of Exhibit ____(MJM-1), which is the basis for his recommended service lives for plant Accounts 369, 376, and 382. Since the figures shown on these pages are impossible to verify, they are without probative value and should be ignored. Consequently, the service lives and depreciation rates recommended by Mr. Majoros for these accounts, which were based on these figures, should be rejected.

In addition, Mr. Majoros mishandled cost transfers in his analysis. In his Geometric Mean Turnover (GMT) analyses for Accounts 369, 376, and 382, Mr. Majoros failed to properly account for cost transfers. Specifically, he failed to properly account for the fact that in 1989 a large amount of costs (8% of the account balance) was transferred from Account 376 – Distribution Mains to Account 380 – Services. In his GMT analysis, Mr. Majoros treated these costs as if they were new assets, rather than partially depreciated assets for which accumulated depreciation had been recorded. This failure to properly handle these transfers has the effect of overstating the average life for Account 376.[91] Presumably, Mr. Majoros also failed to properly handle transfers in his SPR analysis, but since he refused to provide the computer model used to perform the SPR analysis it is impossible to verify this.

Other Expense Issues.

Two expense items were the subject of data requests, but were not discussed in Delta's rebuttal testimony or any testimony submitted by the AG. They were discussed by Mr. Brown during his direct examination at the hearing.[92] First, there should be a reduction of $12,000 in test year depreciation expense to reflect the amortization of an

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[91] Seelye Direct Testimony at 10.
[92] TE at 87.

acquisition adjustment. This issue was discussed in response to data request AG 2-2. Second, there should be an increase of $2,800 in depreciation expense in the form of accretion expense on asset retirement obligations relating to SFAS No. 143. This issue was discussed in response to data request AG 2-41(a).

DEPRECIATION RATES

Delta submitted a depreciation study performed by The Prime Group, LLC containing proposed new depreciation rates and seeks approval of them in this proceeding. Delta's proposed depreciation rates should be approved as filed.

Delta has proposed to lower test-year depreciation expenses by $145,431. Mr. Majoros is proposing to lower test-year depreciation expenses by an additional $747,744.[93] By proposing understated depreciation rates, Mr. Majoros's proposal has the effect of pushing these costs further out into the future, which causes customers ultimately to pay more in interest charges, return on equity and income taxes than they would otherwise. His proposal would have the effect of preserving the value of the assets on Delta's books for a longer period, resulting in customers paying much more carrying costs. The more prudent approach – particularly after considering that Mr. Majoros has failed to support his recommended service lives – is to allow Delta to implement its proposed depreciation rates and to approve the pro-forma level of depreciation expenses proposed by Delta in this proceeding. Since Mr. Majoros's proposed service lives have not been supported by evidence that can be verified, the only reasonable alternatives available to the Commission are (i) to retain Delta's current depreciation rates or (ii) to approve the depreciation rates proposed by Delta in this proceeding. In contrast to Mr.

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[93] See Henkes Direct Testimony, Sch. RJH-5

Majoros, the analysis, work papers and the computer model used to determine the service lives proposed by Delta were provided to all parties for scrutiny. Delta has supported its proposed depreciation rates with an extensive analysis. It is therefore appropriate that these proposed depreciation rates should be implemented.

COST OF CAPITAL

The Company's capital structure, including ratios and cost of capital at December 31, 2003, is set forth in Tab 27 of the Filing Requirements, Schedule 9. The revised and updated version of this schedule was filed with Mr. Hall's rebuttal testimony and entitled "Application Tab 27, Schedule 9."[94] The annual cost rate for long term debt is 7.422%. Long term debt comprises 46.68% of Delta's capital structure. The annual cost rate for short term debt as of December 31, 2003, was 2.478%. Short term debt comprises 15.08% of Delta's capital structure. At the hearing, Mr. Hall stated that the current short term cost rate was 2.51375%.[95] While the AG takes issue with the ratios insofar as they are affected by the restatement of Minimum Pension Liability, he does not take issue with the long term or short term debt cost rates. Delta has proposed an annual cost rate of 12.50% for its common equity, with which the AG disagrees. The AG's witness, Charles W. King, originally recommended a return on common equity of 10.05%, but after discovering errors in his original calculations, he submitted corrected testimony in which he recommended a return on common equity of 10.3%.[96]

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[94] The revision to the capital structure was made to recognize the proper treatment of Minimum Pension Liability. See pp. 6-7 above.
[95] TE at 60.
[96] King Corrected Direct Testimony at 20.

Delta offered the direct and rebuttal testimony of Dr. Martin J. Blake on the subject of the cost of common equity. Dr. Blake analyzed Delta's cost of common equity using the discounted cash flow model (DCF), capital asset pricing model (CAPM) and risk premium approach.[97] Mr. King only used the DCF and CAPM methodologies.[98]

The evidence on the record in this proceeding supports Dr. Blake's recommendation that Delta be allowed a 12.5% return on equity. Dr. Blake has demonstrated that Delta is considerably smaller than most other natural gas distribution utilities, and that Delta is also more highly leveraged than most other natural gas utilities.[99] Thus, Delta is not like other natural gas distribution utilities that the Commission regulates, and a return on equity similar to these larger and less leveraged companies would not be appropriate. In fact, both Delta's size and leverage suggest that Delta should receive a return on equity that is higher than the return on equity for the other natural gas distribution utilities that the Commission regulates

When the errors in Mr. King's direct testimony are corrected (in addition to the ones he corrected), his testimony also supports a finding that a 12.5% return on equity would be reasonable for Delta. Without the admittedly subjective adjustments that Mr. King made to his Exhibit CWK-3,[100] which calculated DCF results for Delta alone, the results from the straight application of the DCF formula showed a 13.3% return on equity.[101] On cross examination, Mr. King admitted that the "peer group" that he used in calculating the DCF results reported in Exhibit CWK-1 included five companies that had substantial unregulated income and which are more properly classified as diversified

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[97] Blake Direct Testimony at 18-20.
[98] King Corrected Direct Testimony at 20.
[99] Blake Direct Testimony at 9-10, 15-16.
[100] King Corrected Direct Testimony at 16.
[101] TE at 282.

companies rather than as natural gas distribution utilities.[102] When these five companies are excluded from Mr. King's "peer group," the calculated DCF results would be higher.

Additionally, when these five diversified companies are eliminated, Delta had the second lowest equity ratio of the natural gas utilities in the panel. This is important because, as Dr. Blake demonstrated in his direct testimony, a lower equity ratio causes Delta's earnings to be more volatile and thus makes it more difficult for Delta to earn its allowed rate of return.[103] This is likely one of the reasons why Delta has not earned its allowed rate of return in any of the past nine years, including two years immediately following rate proceedings.[104] It is necessary for the Commission to include a leverage adjustment in its return on equity because, as Dr. Blake noted in his direct testimony, "just like shooting at a target a long way off, it is necessary for the Commission to aim a bit high in order to hit what it is really aiming at, and this is what the leverage premium accomplishes."[105]

Mr. King did not attempt to rebut the negative impact that a low equity ratio has on return on equity, but instead tried to claim that Delta does not have a low equity ratio.[106] To support this claim, Mr. King compared equity ratios calculated for the year ending September 30, 2003, for a "peer group" of natural gas utilities with Delta's equity ratio on March 30, 2004.[107] In his rebuttal testimony and during the hearing, Dr. Blake pointed out that comparing results at different points of time is invalid.[108] This amounts to comparing apples and oranges. Natural gas distribution utilities generate the bulk of

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[102] TE at 272. See also Blake Rebuttal Testimony at 10-12.
[103] Blake Direct Testimony at 9-13.
[104] Blake Direct Testimony at 8-9.
[105] Blake Direct Testimony at 21.
[106] King Corrected Direct Testimony at 10.
[107] King Corrected Direct Testimony, Exhibit___(CWK-2)
[108] Blake Rebuttal Testimony at 13; TE at 151-152.

their revenues during the winter heating season and their cash position, retained earnings and equity ratio are at the highest at the end of the heating season, which a measurement at the end of March would reflect. Their cash position, retained earnings and equity ratio would be at the lowest at the beginning of the heating season, which is what a measurement at the end of September would reflect. Thus, to support his contention that Delta does not have a low equity ratio, Dr. King compared the equity ratio at the lowest point during the year for other natural gas utilities to the equity ratio at the highest point during the year for Delta. This is clearly an invalid comparison, and Mr. King's assertion that Delta does not have a low equity ratio compared to other natural gas utilities should be rejected. The impact of Delta's low equity ratio on its return on equity should be recognized by the Commission and a leverage adjustment should be included in Delta's allowed return on equity.

Furthermore, Mr. King has failed to address the inability of Delta to earn its allowed return. On page 12 of his Direct Testimony, Mr. King states that Delta's earnings have remained within a band of $.75 to $1.49 per share over the last 10 years. This is a difference of about 100% which simply cannot be regarded as small. Mr. King has not rebutted the fact that Delta has not earned a return on shareholder equity as high as the allowed rate of return in any of the last nine years. For the last nine years, Delta has averaged a 9.16% return on shareholder equity with the return on equity in any single year never equaling or exceeding the 11.6% return on equity authorized in Delta's last rate case.[109]

On page 11 of his Direct Testimony, Mr. King admits that research shows that small companies have earned higher rates of return on equity over time than large

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[109] Blake Direct Testimony at 8-9.

companies and that the variation in those rates of return has been higher as well – implying greater risk. Even after removing the five diversified companies, the smallest company in Mr. King's "peer group" is twice as large as Delta and the largest company is eighty-five times as large. With this "peer group," a size adjustment is clearly necessary if return on equity varies with the size of the company, which research indicates that it does. During cross examination, Mr. King stated that he is dubious of the research results that indicate that a size premium is necessary when comparing small companies with larger companies.[110] However, he cited no research either in his direct testimony or during his cross examination that would support the position that a size adjustment is not necessary. In his direct and rebuttal testimony, Dr. Blake cited numerous examples of published research that indicate that smaller stocks have a higher average return and that a size adjustment is necessary to properly compare CAPM and DCF results for companies of different sizes.[111]

Mr. King attempted to adjust for size, even though he stated that he did not think that it was necessary.[112] However, his attempt at adjusting for size was incorrect for two reasons. First, Mr. King utilized the geometric mean in making the size adjustment rather than the arithmetic mean.[113] As noted in the *SBBI 2003 Yearbook*, which is a part of the same series of publications that Mr. King used to obtain the data for his size adjustment, the arithmetic mean rather than the geometric mean should be used for computing the cost of capital.[114] Second, Mr. King applied the size adjustment in the aggregate rather than on a company by company basis based on the actual capitalization of each

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[110] TE at 278.
[111] Blake Direct Testimony at 15-16; Blake Rebuttal Testimony at 1-4.
[112] King Corrected Direct Testimony at 13.
[113] *Id.*
[114] Blake Rebuttal Testimony at 4-5.

company.[115] This is particularly troubling when Mr. King's peer group includes companies that range from large to micro-cap with regard to their total capitalization.

When the arithmetic mean is used rather than the geometric mean and when the size adjustment is made on a company by company basis rather than in the aggregate, Mr. King's DCF results averaged 13.1% as shown in Exhibit MJB-15. Similarly, when Mr. King's CAPM results are adjusted for size in the correct manner, the calculated return on equity is 12.8%, as shown in Exhibit MJB-17. When the errors made by Mr. King are corrected, both his DCF and CAPM results support Dr. Blake's recommendation of a 12.5% allowed return on equity.

Furthermore, the use of a 12.5% allowed return on equity would produce reasonable results. Exhibit MJB-10 shows that the resulting interest coverage for Delta, if a 12.5% rate of return is used, would still be the fifth lowest in the panel and well below the mean and median interest coverages for the fifteen natural gas distribution companies included in the Edward Jones report. Exhibit MJB-11 shows that the estimated range for return on equity calculated using DCF for the other fourteen natural gas distribution companies in the Edward Jones panel would be from a low of 7.57% to a high of 13.27%. In Exhibit MJB-11, the estimated range of returns on equity using CAPM for the other fourteen natural gas distribution companies in the Edward Jones panel is 10.69% to 14.15%. Thus, based on interest coverage and the calculated return on equity for the other fourteen natural gas distribution companies in his panel, the 12.5% return on equity that Dr. Blake recommended for Delta is clearly reasonable.

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[115] TE at 277.

COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN

Delta's cost of service study should be used as a guide for setting rates. Delta submitted a fully allocated, embedded cost of service study based on operating results for the12 months ended December 31, 2003. The cost of service study, which was included as exhibits to the direct testimony of Mr. Seelye, was performed using standard cost of service methodologies which have been accepted by the Commission in prior rate cases.[116]

AG witness David H. Brown Kinloch submitted an alternative cost of service study which modified the classification of distribution mains in Delta's cost of service study. In Delta's cost of service study, distribution mains were classified as customer-related and demand-related by applying a weighted least squares analysis to actual plant costs for each size of distribution mains.[117] Mr. Brown Kinloch performed a least squares analysis using only two pipe sizes – 2-inch plastic mains and 4-inch plastic mains.[118] Statistically, a least squares analysis using only two arbitrarily selected data points is meaningless and does not account for variation in the data.[119] Mr. Brown Kinloch failed to use a standard statistical approach in eliminating the data points that were removed. Consequently, the cost of service study submitted by the AG should be rejected. Delta's cost of service study should be used as a guide for setting rates.

The rates to Delta's special contract customers should not be modified, as Mr. Brown Kinloch has suggested. Delta did not propose any increases to its four special

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[116] *In the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc.*, Case No. 99-176, Order dated December 27, 1999, at 36; *In the Matter of: The Application of Louisville Gas and Electric Company to Adjust its Rates, Etc.*, Case No. 2000-080, Order dated September 27, 2000, at 71.
[117] Seelye Direct Testimony at 15-16.
[118] Brown Kinloch Direct Testimony at 8.
[119] Seelye Rebuttal Testimony at 18-20.

contract customers. Mr. Brown Kinloch proposes to increase the transportation rates to these customers by 10.08%.[120] The contracts for these four customers establish a fixed price over the term of the agreement. Three of these customers are located near interstate pipelines and could by-pass Delta's transmission system.[121] The other customer is located near local natural gas production and could also by-pass Delta's transmission system.[122] If these customers were to connect to another pipeline, then Delta would lose $631,225 in revenue.[123] The $631,225 in fixed cost recovery would have to be recovered from other customers, principally residential customers.

Mr. Jennings offered the following additional reasons for rejecting Mr. Brown Kinloch's suggestion that the special contract customers' rates be increased:

> Those special contracts set forth the terms, including pricing, to which Delta and the customer have agreed. The Commission has accepted these contracts. It would be unfair to those customers to now increase the pricing of our services during the contract terms. In addition, it would be detrimental to future economic development efforts. It could also result in potential loss of customers.[124]

The AG's proposed increase to these special contract customers should be rejected.

Delta's proposed residential customer charge is reasonable. Delta is proposing to increase the residential customer charge from $8.00 to $12.50 per month. Even at this level, the customer charge would still be significantly less than the level indicated by Delta's cost of service study. Delta's cost of service study indicates that a customer

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[120] Brown Kinloch Direct Testimony at 13; Seelye Rebuttal Testimony at 21.
[121] Seelye Rebuttal Testimony at 21.
[122] *Id.*
[123] *Id.*
[124] Jennings Rebuttal Testimony at 1.

charge of $21.51 per month could be supported.[125] Even Mr. Brown Kinloch's flawed cost of service study could support a residential customer charge of $14.70 per month.[126] Delta's proposed customer charge, which is only 58% of a cost-based customer charge ($12.50 ÷ $21.51 = 58.11%), is reasonable.

GTI R&D TARIFF RIDER

Delta has requested the approval of a new tariff that will provide for the collection of revenue to maintain the Company's level of contribution to the Gas Technology Institute for Research and Development (GTI R&D).[127] Delta is currently being billed by the interstate pipelines with which it does business for the collection of the GTI R&D fee.[128] Under the proposed tariff Delta will include a charge of $0.003 per mcf of gas sold by Delta to its sales customers.[129] The funds collected will be paid to GTI R&D. The proposed rate is based on the Company's 2003 level of contribution to GTI R&D, which was $12,347.[130] In the event that Delta ceases participation in the funding of GTI R&D in the manner currently proposed, then Delta would terminate the proposed rider.[131]

GTI R&D conducts the lion's share of the research and development for the entire gas industry.[132] The research and development that GTI R&D performs is available to the gas industry as a whole, including Delta, and Delta would have the benefit of those efforts even if Delta did not specifically request that the research and development be

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[125] Seelye Direct Testimony at 28.
[126] Seelye Rebuttal Testimony at 23.
[127] Hall Direct Testimony at 3.
[128] *Id.*
[129] *Id.*
[130] *Id.*
[131] Tab 7 of the Filing Requirements, Original Sheet No. 34.
[132] TE at 55.

done.[133] Research and development by GTI R&D includes such areas as safety, efficiency and gas costs.[134] Thus, Delta's contributions will benefit Delta's customers.

Delta has chosen not to seek recovery of the contribution from its transportation customers because those customers are not currently paying the contribution to Delta.[135] Delta pays the contribution to the interstate pipelines with which it does business. The interstate pipeline charges are components of the costs paid by Delta's sales customers, not the costs paid by its transportation customers.

The proposed GTI R&D tariff rider is reasonable and should be approved.

CONCLUSION

Based upon the record and the foregoing authorities, the Commission should approve fair, just and reasonable rates for Delta that will produce $4,510,815 in additional annual revenues. The Commission should also approve Delta's proposed depreciation rates and its proposed GTI R&D tariff rider.

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[133] TE at 65.
[134] TE at 62.
[135] TE at 53.

CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by mailing a copy of same, postage prepaid, to the following person on this 10th day of September 2004:

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