BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

October 20, 2004

IN RE:	)	
	)	
PETITION OF CHATTANOOGA GAS COMPANY	)	**DOCKET NO.**
FOR APPROVAL OF ADJUSTMENT OF ITS	)	**04-00034**
RATES AND CHARGES AND REVISED TARIFF	)	

ORDER

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IN RE: PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND CHARGES AND REVISED TARIFF, DOCKET NO. 04-00034

This matter came before Chairman Pat Miller, Director Deborah Taylor Tate and Director Sara Kyle of the Tennessee Regulatory Authority (the "Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on August 30, 2004, for consideration of the *Petition of Chattanooga Gas Company for Approval of Adjustment of its Rates and Charges and Revised Tariff* (the "*Petition*") filed on January 26, 2004, and tariff revisions filed on March 1, 2004. Upon consideration of the entire record, including all exhibits and the testimony of the witnesses, the panel concluded that Chattanooga Gas Company ("CGC" or "the Company") had a Revenue Deficiency of $642,777, to be allocated evenly to all customer classes except Special Contracts and allocated to volumetric rates only. Based upon a Revenue Deficiency of $642,777, this allocation will produce a 2.00% increase to all customer classes except Special Contracts. These conclusions, as well as other decisions concerning the rate base, net operating income, fair rate of return, rate design and tariff adjustments, are fully discussed below.

I. TRAVEL OF THE CASE

On January 26, 2004, the Company filed its *Petition* with the Authority pursuant to Tenn. Code Ann. § 65-5-203, to place into effect a revised natural gas tariff, superceding its existing tariff and rate schedule previously filed with the Authority. CGC is a wholly-owned subsidiary of AGL Resources, Inc. ("AGLR").

At a regularly scheduled Authority Conference held on February 9, 2004, the panel voted unanimously to suspend the *Petition* and the rates filed therewith through May 29, 2004 and to appoint a Hearing Officer in this proceeding to hear preliminary matters prior to the Hearing. On March 1, 2004, the Company filed revisions to its tariff which replaced rates that had been a part of the *Petition* filed on January 26, 2004.

On February 26, 2004, the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") filed a Petition to Intervene in this docket questioning the reasonability of the requested rate increases and asserting that approval of the petition, as presently filed, is not in the public interest. On March 2, 2004, the Chattanooga Manufacturers Association ("CMA"), a trade association representing over 250 manufacturers and other businesses, filed a Petition to Intervene stating that the proposed increases to certain rates and charges sought by CGC would adversely affect rate payers, including members of the CMA. On April 16, 2004, Gas Technology Institute ("GTI") filed a Petition to Intervene. GTI alleged as a basis for intervention that a charge, approved by the Federal Energy Regulatory Commission ("FERC") and currently being recovered from rate payers for research and development, would be discontinued by the end of 2004. GTI sought to have that charge implemented by the TRA as a part of the TRA's consideration of CGC's rate case.

The TRA issued Data Requests to the Company on February 6 and 25, March 8, 11, 15 and 19 and April 15, 21 and 22 seeking information in support of CGC's filings. The Company responded to these Data Requests, continuing to provide information in compliance with the TRA's Minimum Filing Requirements.

A Status Conference was held on April 19, 2004 for the purpose of discussing issues and establishing a procedural schedule During the Status Conference, the Hearing Officer considered the pending Petitions to Intervene, which were not opposed by CGC. The Hearing Officer found that the Petitions to Intervene met the criteria in Tenn. Code Ann. § 4-5-310(a) and granted intervention to the Consumer Advocate, CMA and GTI. The Hearing Officer, with the cooperation of the parties, established a preliminary procedural schedule to commence discovery between the parties and scheduled another Status Conference for May 10, 2004 to address any discovery objections and motions to compel.

The Hearing Officer also asked the parties during the Status Conference to notify the Authority no later than April 26, 2004 if any party had an objection to Hal Novak, presently Chief of the TRA Energy and Water Division, serving as an advisor to the Directors in this matter.[1]

The parties engaged in discovery pursuant to the procedural schedule. A Status Conference was held on May 10, 2004 at which time the Hearing Officer considered motions to compel discovery filed by CGC and the Consumer Advocate. During the Status Conference, the Hearing Officer issued rulings on specific objections to discovery from the Company to the Consumer Advocate and CMA, and from the Consumer Advocate to the Company.[2]

On May 13, 2004, the Consumer Advocate filed a *Motion to Extend the Hearing Time to Nine Months* ("*Motion*"). CGC filed a Response to the Consumer Advocate's *Motion* on May 21, 2004. The TRA issued additional Data Requests to the Company on May 14, 19, 20 and 21 to which CGC responded on May 24 and 28 and June 2 and 3. On May 28, 2004, the Hearing Officer entered an Order suspending the effective date of the tariff filed in this docket with the *Petition* through July 28, 2004

On July 9, 2004, CGC filed with the Authority a written request advising the Authority

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[1] Hal Novak was formerly employed by Atlanta Gas and Light, the parent corporation of Chattanooga Gas Company, and by Sequent Energy, a subsidiary of Atlanta Gas and Light, before coming to the TRA in July, 2003 The Consumer Advocate filed the only response to the Hearing Officer's inquiry and stated that its office did not oppose Mr Novak acting in an advisory role in this proceeding

[2] Other objections were reviewed by the Hearing Officer and those that remained were ruled on in an *Order Resolving Motions to Compel* issued July 20, 2004

that the Company intended to place a tariff into effect for billing cycles after August 1, 2004 and asking the Authority to waive the bond requirement in Tenn. Code Ann. § 65-5-203(b)(1).[3]

After reviewing the July 9, 2004 filing by CGC, the Hearing Officer determined that, to the extent that any of the rates, charges, schedules or classifications in the tariff filed on July 9, 2004 had not been on file with the Authority a full six (6) months, as required by Tenn. Code Ann. § 65-5-203(b)(1), such rates, charges, schedules or classifications could not be put into effect "for billing cycles after August 1, 2004," and could not be put into effect until a full six month period has expired. The Hearing Officer directed CGC to identify and segregate those rates, charges, schedules or classifications that would be eligible to go into effect on July 26, 2004 and those rates, charges, schedules or classifications that would not be eligible to go into effect on July 26, 2004 but at a later date. The Hearing Officer suspended until August 27, 2004 the effectiveness of those rates, charges, schedules or classifications contained in the tariff filed by CGC on July 9, 2004 that have not been on file with the Authority a full six (6) months on July 26, 2004.[4]

The Hearing Officer also issued an *Order Establishing Schedule for Responses to Chattanooga's Motion filed July 9, 2004 and Reply Thereto*, which set forth a schedule for the filing of responses to CGC's request and of CGC's reply to any such responses. The Hearing Officer set the deadline for filing responses on July 19, 2004 and for filing a reply on July 22, 2004.

In an Order issued on July 12, 2004, the Hearing Officer determined that the Consumer Advocate's *Motion* was not proper and denied that motion In the absence of an agreed schedule,

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[3] *See Notice of Intention to Place Proposed Rates into Effect, Request to Waive Bond and Request to Determine Method for Calculating Interest on Refunds, If Any* (July 9, 2002)

[4] *See Order Requiring Chattanooga Gas Company To Identify All Rates, Charges, Schedule Or Classification In Its July 9, 2004 Tariff On File For Six Months And Suspending The Effectiveness Of All Other Rates, Charges, Schedules Or Classification In The July 9, 2004 Tariff* (July 12, 2004)

the Hearing Officer established a procedural schedule based on a Hearing to be held during the week of August 23, 2004.

On July 19, 2004, the Consumer Advocate and CMA filed responses to CGC's July 9, 2004 motion. Also, on July 19, 2004, CGC filed a letter in compliance with the Hearing Officer's July 12, 2004 Order, identifying any rates, charges, schedules and classifications that would not be on file with the Authority for six months as of July 26, 2004. CGC reiterated its intent to place in effect "all other rates ... for billing cycles on or after August 1, 2004."[5]

On July 21, 2004, the Hearing Officer held a telephonic status conference with all parties to discuss the July 19, 2004 filings of the parties and the impact of CGC's request on the procedural schedule and hearing date. The discussions focused on adjusting the procedural schedule to move up the date of the hearing and conclusion of this docket in light of the Company's July 9, 2004 filing. The status conference was adjourned at the request of representatives of CGC to provide them an opportunity to discuss whether to move the date proposed for putting certain rates into effect to allow for a hearing in August.

On the afternoon of July 21, 2004, counsel for CGC contacted the Hearing Officer and the Intervenors through electronic messaging with a proposal for moving to September 1, 2004 the date for putting rates into effect. CGC proposed to proceed with the Hearing during the week it was originally scheduled, except that it wanted to start the Hearing on August 24 instead of August 23, 2004.[6] The Hearing Officer entered an Order on July 26, 2004 reflecting the agreement of the parties regarding the Hearing and the proposed date for putting rates into effect.

On July 26, 2004, the Intervenors submitted pre-filed testimony as follows: The Consumer Advocate filed the direct testimony of Steve Brown, Michael D. Chrysler, Daniel W.

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[5] Letter from D Billye Sanders, Esq. to Pat Miller, Chairman of the TRA, p 1 (July 19, 2004)

[6] *See Order Approving Agreement of Parties Regarding Effectiveness of Rates and Procedural Matters* (July 26, 2004)

McCormac, and Danny L. McGriff, Manager, Facilities Protection Section of the Georgia Public Service Commission; and CMA filed the direct testimony of Alan Chalfant, Earl Burton, Tim Spires, Ray Childers, President, Chattanooga Manufacturers Association, and Dan Nuckolls, Operations Director for Koch Foods, LLC. On August 16, 2004, CGC filed the rebuttal testimony of Steve Lindsey, Michael Morley, Richard Lonn, Roger A. Morin, Darilyn Jones and Doug Schantz.

A Pre-Hearing conference was held on August 18, 2004, at which time the Hearing Officer established the order of proof and resolved several procedural matters in advance of the Hearing. On August 24, 2004, the Hearing Officer entered an Order severing the request of GTI from this docket.[7]

II. THE HEARING AND APPEARANCES

The Hearing in this matter was held before the voting panel on August 24 and 25, 2004. Closing arguments were presented on August 26, 2004. Participating in the Hearing were the following parties and their respective counsel:

> **Chattanooga Gas Company** – D. Billye Sanders, Esq., Waller, Lansden, Dortch & Davis, 511 Union Street #2100, Nashville, Tennessee 37219-1750 and L. Craig Dowdy, Esq., McKenna, Long & Aldridge, LLP, 303 Peachtree Street, NE, Suite 5300, Atlanta, Georgia 30308;
>
> **Consumer Advocate and Protection Division** - Vance Broemel, Esq. and Timothy C. Phillips, Esq., Office of the Attorney General, P.O. Box 20207, Nashville, Tennessee 37202;
>
> **Chattanooga Manufacturers Association** - Henry Walker, Esq., Boult, Cummings, Conners & Berry, PLC, 414 Union Street, Suite 1600, Nashville, Tennessee 37219 and David C. Higney, Esq., Grant, Konvalinka & Harrison, P.C., 633 Chestnut Street, 9th Floor, Chattanooga, Tennessee 37450.

[7] *See Order Granting Motion to Sever of the Chattanooga Manufacturing Association* (August 24, 2004) This Order was entered reflecting an earlier determination by the Hearing Officer granting a *Motion to Sever* filed by CMA on April 23, 2004

At the August 24, 2004 hearing, Director Tate made three separate motions to remove the following items from consideration in this proceeding: the Chattanooga Assisted Rate for Energy Services ("CARES") program, the quality of service reporting and benchmarks, and the industrial tariff.[8] Counsel for CGC stated that the Company had no objection to removing the CARES program from consideration in this docket, nor did it oppose removing the quality of service reporting and benchmarks from consideration in this docket.[9] Regarding the industrial tariff, Counsel for CGC stated that a settlement had been reached with the Chattanooga Manufacturers Association and requested that the settlement be approved.[10] The Consumer Advocate agreed with the removal of the CARES program and the quality of service reporting and benchmarks as items for consideration in this docket.[11] In addition, the Consumer Advocate did not oppose the settlement reached by the CGC and the CMA regarding the industrial tariff.[12] Counsel for CMA stated their support for removing the above-identified items from consideration in this docket and for the settlement agreement reached with the CGC regarding the industrial tariff.[13]

Thereafter, based on the parties' agreement that the CARES program and the quality of service reporting and benchmarks should be removed as items for consideration in this docket and the settlement agreement regarding the industrial tariff reached between the Chattanooga

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[8] Transcript of Proceedings, v I, pp 8-12 (August 24, 2004)

[9] Transcript of Proceedings, v I, pp. 15-16 (August 24, 2004) *See also* Transcript of Proceedings, v III, p 3 (August 24, 2004)

[10] Transcript of Proceedings, v I, pp 16-17, 21 (August 24, 2004)

[11] Transcript of Proceedings, v. I, p 28-29 (August 24, 2004) *See also* Transcript of Proceedings, v II, p 20 (August 24, 2004)

[12] Transcript of Proceedings, v III, p 4 (August 24, 2004)

[13] Transcript of Proceedings, v I, pp 44-46 (August 24, 2004) *See also* Transcript of Proceedings, v III, p 6 (August 24, 2004)

Gas Company and the Chattanooga Manufacturers Association, Director Tate withdrew the three separate motions noted above.[14]

III. CRITERIA FOR ESTABLISHING JUST AND REASONABLE RATES

The Authority is obligated to balance the interests of the utilities subject to its jurisdiction with the interests of Tennessee consumers, i.e., it is obligated to fix just and reasonable rates.[15] The Authority must also approve rates that provide regulated utilities the opportunity to earn a just and reasonable return on their investments.[16]

The Authority considers petitions for a rate increase, filed pursuant to Tenn. Code Ann. § 65-5-203, in light of the following criteria:

1. The investment or rate base upon which the utility should be permitted to earn a fair rate of return;
2. The proper level of revenues for the utility;
3. The proper level of expenses for the utility; and
4. The rate of return the utility should earn.

The general standards to be considered in establishing the costs of common equity for a public utility are financial integrity, capital attraction and setting a return on equity that is commensurate with returns investors could achieve by investing in other enterprises of corresponding risk. The utility's cost of common equity is the minimum return investors expect, or require, in order to make an investment in the utility. The proper level of return on the Company's capital, including equity capital, must allow a return on capital that is commensurate with returns on investment in other enterprises having corresponding risk.[17]

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[14] Transcript of Proceedings, v. III, p 6 (August 24, 2004)
[15] Tenn Code Ann § 65-5-201 (Supp 2002)
[16] *See Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U S 679, 43 S Ct 675 (1923)
[17] *See Federal Power Commission v Hope Natural Gas Co* , 320 U S 591, 64 S Ct 281 (1944)

In determining a fair rate of return, the Authority must conduct an in-depth analysis and give proper consideration to numerous factors, such as capital structure, cost of capital and changes which can reasonably be anticipated in the foreseeable future. The Authority has the obligation to make this determination based upon the controlling legal standard set forth in the landmark cases of *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*[18] and *Federal Power Commission v Hope Natural Gas Company,*[19] which have been specifically relied upon by the Tennessee Supreme Court.[20]

In the *Bluefield* case, the United States Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[21]

Later, in the *Hope* case, the United States Supreme Court refined these guidelines, holding that:

> From the investor or company points of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.[22]

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[18] *Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U S 679, 43 S Ct 675 (1923)
[19] *Federal Power Commission v Hope Natural Gas Co* , 320 U S 591, 64 S Ct 281 (1944)
[20] *Southern Bell Telephone & Telegraph Co v Public Service Commission*, 304 S W 2d 640, 647 (1957)
[21] *Bluefield,*, 262 U S at 692-93
[22] *Hope*, 320 U S at 603

Applying these principles, and upon consideration of the entire record, including all exhibits and the testimony of the witnesses, the panel made the following findings and conclusions.

IV. TEST PERIOD

In a rate case the Authority must, as a preliminary determination, decide which test period is appropriate. The purpose in the selection of a test period is to provide an indication of the rate of return that is likely to be produced under the existing rate structure in the reasonably foreseeable future. The test period takes into consideration the estimated effect of reasonably expected revenues, expenses and investments.

The Company proposed a historical test period for the twelve (12) months that ended September 30, 2003, with adjustments for attrition through June 30, 2005. Each of the Parties in this case adopted this same test period for their forecasts. The Authority concluded that this was a reasonable and appropriate test period in this case for rate setting purposes and would provide the Company the opportunity to earn a fair rate of return on its investment.

V. CONTESTED ISSUES

In its original filing of January 26, 2004, the Company requested a revenue increase of $4,560,699. Also in its original filing, the Company included two tariffs. The first tariff or Primary Filing allocates the entire $4,560,699 revenue increase uniformly across all customer classes. The second tariff, described as the Preferred Alternative by the Company, moves the recovery of carrying costs related to gas inventory to the Company's Purchased Gas Adjustment ("PGA") and creates a separate surcharge from base rates for the cost of the Company's Bare Steel and Cast Iron Replacement Program. The Company states that these two adjustments, if approved, would lower its revenue increase request to $2.4 million.

The Consumer Advocate asserted that a rate increase would not be just and that the Company should be ordered to reduce its current rates by $2,572,229.[23] The CMA did not propose an adjustment to the Company's revenue request, but instead took issue with certain non-rate adjustments the Company had proposed to its industrial tariff.

On August 16, 2004 the Company filed amended testimony and exhibits that reduced its request for an increase in revenues from $4,560,699 to $3,703,975. The Company stated that this reduction was due to the TRA's decision related to uncollected gas costs in TRA Docket No. 03-00209 and other information related to payroll, benefits and post retirement benefits that was not available when the initial filing was made. The following sections represent the issues contested by the Parties.

V(a). <u>RATE BASE</u>

Rate Base is the Company's net investment, which is financed through investor-supplied funds, in property used and useful in providing utility service. This is the amount of investment on which the Company should be allowed the opportunity to earn a fair and reasonable rate of return. The Company forecasted a Rate Base of $95,473,111 in its amended filing,[24] while the Consumer Advocate proposed $94,939,114.[25]

The following sections represent the various components to the Rate Base calculation.

V(a)1. UTILITY PLANT IN SERVICE

Plant in Service represents the original investment cost to the Company of the assets used in providing utility service. The Company included $164,561,353 in its Primary Filing related to the forecasted average value of Plant in Service.

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[23] Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedule 1 (July 26, 2004)
[24] Michael J Morley, Pre-Filed Rebuttal Testimony, Exhibit MJM 7-6 (August 16, 2004)
[25] Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedule 2 (July 26, 2004)

In its Preferred Alternative Filing, however, the Company proposed to remove its future plant and construction costs related to replacing its existing bare steel and cast iron pipe from its filing and instead to recover these costs through a separate tracking mechanism. The Company stated that it has approximately 100 miles of bare steel and cast iron pipe that now needs to be replaced at a cost of approximately $37 million over the next ten years.[26] The tracking mechanism proposed by the Company would allow it to adjust rates to reflect the incremental depreciation and return on investment in pipeline replacement outside of a rate case.

In its filing, the Consumer Advocate accepted the $164,561,353 figure included in the Company's Primary Filing related to the forecasted average value of Plant in Service. Nevertheless, the Consumer Advocate opposed the implementation of a separate tracker for pipeline replacement. The Consumer Advocate expressed concern about the Company's ability to inflate the costs of such a program outside of a rate case and stated that a similar program in Georgia placed a tremendous burden on the Georgia Commission's Staff.[27]

The panel determined that the Company's replacement of its existing bare steel and cast iron pipe was properly recovered through a rate case instead of through a separate surcharge. In reaching this decision, the panel found that such a plan would not make for sound regulatory policy and could place a strain on the Authority's limited staffing resources. Therefore, the panel adopted the $164,561,353 amount included in the Company's Primary Filing and accepted by the Consumer Advocate as the proper estimate for Plant in Service.[28]

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[26] Richard Lonn, Pre-Filed Direct Testimony, pp 2, 5 (January 26, 2004)

[27] Michael D Chrysler, Pre-Filed Direct Testimony, p 8 (July 26, 2004) and Danny L McGriff, Pre-Filed Direct Testimony, p 3 (July 26, 2004).

[28] Although in agreement with the rest of the panel that the bare steel and cast iron pipeline replacement tracker was not within the purview of case, Director Tate dissented on this issue, stating that the pipeline tracker would more accurately reflect company costs and suggested that a generic docket might be opened to allow all gas companies and other interested parties to file comments on this issue.

V(a)2. CONSTRUCTION WORK IN PROCESS

Construction Work in Process ("CWIP") represents the cost of investment that is currently under construction and will be transferred to Plant in Service when completed. Both the Company and the Consumer Advocate adopted $3,544,977 as the appropriate amount for CWIP. After its own investigation, the panel also concluded that $3,544,977 was the proper and appropriate forecasted amount to include in Rate Base for CWIP.

V(a)3. MATERIALS AND SUPPLIES

Materials and Supplies ("M&S") generally refers to construction inventories M&S includes items such as pipes, meters, and other equipment that will either soon be placed into service or kept on hand for emergency purposes. Both the Company and the Consumer Advocate adopted $170,409 as the appropriate amount for M&S. After reviewing the evidence, the panel also concluded that $170,409 was the proper and appropriate forecasted amount to include in Rate Base for M&S.

V(a)4. GAS INVENTORY

The Company included $14,193,526 in its Primary Filing related to the forecasted average value of Gas Inventory. Gas Inventories represent the average value of gas that the Company stores for withdrawal during the peak winter months. While the actual cost of gas placed into storage is recovered through the Authority's purchased gas adjustment ("PGA") process, the return on the investment required to store gas in inventory is recovered through a rate case proceeding.

In its Preferred Alternative Filing, the Company eliminated forecasted Gas Inventory from Rate Base and instead proposed to recover this carrying value based on the actual amount of inventory through its PGA filings. The Company stated that due to the volatility of gas prices, the value of stored gas could vary drastically from one heating season to another, making this a difficult item to forecast. Further, the Company argued that capitalizing these costs and including them in the PGA properly matches the carrying costs with the actual value of the stored gas.[29]

In its filing, the Consumer Advocate accepted the $14,193,526 amount included in the Company's Primary Filing related to the forecasted average value of Gas Inventory. The Consumer Advocate stated that this amount should be included in Gas Inventory in this case and the Company should not be allowed to recover this cost through its PGA. The Consumer Advocate further stated that the Company has some control over the timing of its injections and withdrawals of gas into and out of storage. The Consumer Advocate concluded that, by including the recovery of Gas Inventory in the PGA, the TRA would be rewarding the Company for bloating the inventory values and thereby shifting the risk of gas inventory management to consumers.[30]

The majority of the panel determined that the carrying cost of gas inventory should be properly recovered through the Company's base rates and not through the PGA as proposed in the Company's Preferred Alternative Filing.[31] Therefore, the panel adopted $14,193,526 included in the Company's Primary Filing and accepted by the Consumer Advocate as the proper estimate for Gas Inventory.

V(a)5. PREPAYMENTS

Prepayments are an investment in working capital made in advance of the period to which they apply and include items such as prepaid rents, insurance and taxes. The amortization

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[29] Steve Lindsey, Pre-Filed Direct Testimony, p 8 (January 26, 2004).

[30] Daniel W McCormac, Pre-Filed Direct Testimony, pp 17-18 (July 26, 2004)

[31] Director Tate dissented on this issue, voting to approve the company's proposal to recover the carrying value of the gas inventory through the PGA, and agreed with Director Kyle that that the TRA might revisit this issue in the Company's next rate case

of these costs are then treated on the income statement as an expense Both the Company and the Consumer Advocate adopted $20,358 as the appropriate amount for Prepayments. After reviewing the record, the panel also concluded that $20,358 was the appropriate forecasted amount to include in Rate Base for Prepayments.

V(a)6. OTHER ACCOUNTS RECEIVABLE

Other Accounts Receivable represents amounts owed to the Company by its customers that are not associated with regular gas service. An example of Other Accounts Receivable would include amounts due from customers for main extensions that are being paid on an installment basis. Both the Company and the Consumer Advocate adopted $57,547 as the appropriate amount for Other Accounts Receivable. After reviewing the record, the panel also concluded that $57,547 was the proper and appropriate forecasted amount to include in Rate Base for Other Accounts Receivable.

V(a)7. DEFERRED RATE CASE EXPENSE

Deferred Rate Case Expense represents the unamortized portion of costs the Company has incurred as a result of regulatory proceedings before the Authority. The Company capitalizes these costs and amortizes them over a previously prescribed period. The amortization of these costs is then treated on the income statement as an expense.

The Company forecasted the total cost of preparing and presenting this rate case to be $298,530. The Company proposed to amortize this cost over a three-year period, resulting in an amortization expense of $100,000 and a forecasted average deferred rate case balance of $250,000.

The Consumer Advocate objected to allowing the Company to recover the cost of preparing and filing this case. According to the Consumer Advocate, the Company was already over earning and rates should therefore be reduced.[32] Nevertheless, the Consumer Advocate also stated that the Company should be allowed to recover its rate case expense if the Company was able to prove that a rate increase was warranted.[33]

The panel determined that the Company had made this rate case filing in good faith and rejected the Consumer Advocate's proposal to remove the cost of preparing this case from the Company's filing. The panel also adopted the Company's proposal to amortize its Deferred Rate Case Expense over a three-year period, resulting in a forecasted amortization of $100,000 with a related forecasted deferral of $250,000 as proposed by the Company.

V(a)9. LEAD/LAG STUDY

The Lead/Lag Study measures the average amount of capital provided by investors, over and above the investment in other Rate Base issues, to finance company activities between the time that expenditures are required to provide services and the time that collections are received for services. The Lead/Lag Study recognizes that there is an investment required on the part of the stockholders to pay for the day-to-day expenses of the utility before they are recovered through rates charged to the ratepayer.

The Consumer Advocate adopted the Company's Revenue Lag Day forecast of 46.05 days; however, the Consumer Advocate computed 41.16 days for the Expense Lag, while the Company proposed 40.41 days. In addition, the Company proposed a Daily Cost of Service of $266,541, while the Consumer Advocate proposed $249,240. These differences were not due to any disagreement between the parties as to the proper individual Expense Lag Day forecasts, but were instead the result of different expense forecasts included in the cost of service as adopted by the Authority elsewhere in this Order.

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[32] Daniel W McCormac, Pre-Filed Direct Testimony, pp. 7, 17 (July 26, 2004)
[33] Transcript of Proceedings, v. VIII, p 57 (August 25, 2004)

The panel found that consideration of each of the expense adjustments produced an Expense Lag of 40.90 days, resulting in a net lag day effect of 5.15 days. In addition, multiplying the net lag days by the daily cost of service of $258,102 and taking incidental collections of $38,953 into consideration, yields $1,367,164 for the results of the Lead/Lag Study.

LEAD/LAG STUDY RESULTS

	Company Original[34]	**Consumer Advocate**[35]	**Company Amended**[36]	**Authority**
Revenue Lag Days	46.05	46.05	46.05	46.05
Expense Lag Days	40.12	41.16	40.41	40.90
Net Lag Days	**5.90**	**4.89**	**5.60**	**5.15**
Daily Cost of Service	$268,902	$249,240	$266,541	$258,102
Operating Funds Advanced	$1,594,457	$1,219,359	$1,503,356	$1,328,211
Incidental Collections	38,953	38,953	38,953	38,953
Lead/Lag Study Results	**$1,633,410**	**$1,258,312**	**$1,542,309**	**$1,367,164**

The panel, therefore, adopted $1,367,164 as the appropriate amount to include for the Lead/Lag component of Rate Base.

V(a)10. ACCUMULATED DEPRECIATION

Recovery of the dollars invested in Plant in Service is permitted over the estimated useful life of the plant by a systematic depreciation charge. The Accumulated Depreciation represents the amount of plant that has previously been recovered from utility customers through the annual Depreciation Expense charges on the income statement. Both the Company and the Consumer Advocate adopted $71,307,914 as the appropriate amount for Accumulated Depreciation. After reviewing the record, the panel also concluded that $71,307,914 was the proper and appropriate forecasted amount to include in Rate Base for Accumulated Depreciation.

[34] Exhibit MJM-3, Schedule 3 (January 29, 2004)
[35] Daniel W. McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedule 5 (July 26, 2004)
[36] Michael J. Morley, Pre-Filed Rebuttal Testimony, Exhibit MJM 7-8 (August 16, 2004)

V(a)11. ACCUMULATED DEFERRED FEDERAL INCOME TAXES

Accumulated Deferred Federal Income Taxes ("ADFIT") represent the accumulated annual differences between accounting or book income and taxable income. Some of these differences are permanent while others involve temporary or timing matters that will reverse in subsequent years. In the case of utilities, the major component of these differences generally involves the accelerated depreciation that is taken on utility plant for tax purposes. The tax effect of the difference between book and tax depreciation methods results in a deferral of income to later periods. These annual deferrals are then credited to the ADFIT account. The ADFIT represents the tax savings of timing differences to the Company that will ultimately turn around. Because the ratepayers' charges are based on book depreciation amounts, the ratepayers are entitled to relief through a reduction in Rate Base for the total amount of ADFIT. Both the Company and the Consumer Advocate adopted $12,012,158 as the appropriate amount for ADFIT. After reviewing the record, the panel also concluded that $12,012,158 was the appropriate forecasted amount to include in Rate Base for ADFIT.

V(a)11. CONTRIBUTIONS IN AID OF CONSTRUCTION

Contributions In Aid of Construction ("CIAOC") represents funds that are received from ratepayers for certain construction projects. These projects are undertaken when the Company's facilities are either extended or relocated at the customer's request in an area that is not likely to be economically feasible to serve under normal conditions. Both the Company and the Consumer Advocate adopted $2,161,125 as the appropriate amount for CIAOC. The panel also concluded that $2,161,125 was the appropriate forecasted amount to include in Rate Base for CIAOC.

V(a)12. CUSTOMER ADVANCES

Customer Advances for Construction represent funds that are advanced from ratepayers for various construction projects. Customer Advances represent a liability on the Company's books, and will eventually be returned to the specific ratepayers who made them. Since Customer Advances are a source of non-investor supplied capital that is used to construct plant, it is proper to make a corresponding reduction in Rate Base. Both the Company and the Consumer Advocate adopted $286,394 as the appropriate amount for Customer Advances. After reviewing the record, the panel also concluded that $286,394 was the proper and appropriate forecasted amount to include in Rate Base for Customer Advances.

V(a)13. RESERVE FOR UNCOLLECTIBLE ACCOUNTS

Reserve for Uncollectible Accounts represents the net accumulation of the Uncollectible Expense that is recognized in net operating income. When expense provisions required to create reserves are allowed in the Company's cost of service, the ratepayer is supplying funds to the utility in advance of the actual need. Since these funds are available to the utility to support its Rate Base investment, the accumulated reserve must be deducted from Rate Base to avoid customers paying a return on funds that they have already supplied. Both the Company and the Consumer Advocate adopted $435,822 as the appropriate amount for the Reserve for Uncollectible Accounts. Based on the record, the panel also concluded that $435,822 was the appropriate forecasted amount to include in the Reserve for Uncollectible Accounts.

V(a)14. CUSTOMER DEPOSITS

Customer Deposits represent funds received from ratepayers as security against potential losses arising from customer failure to pay for service. These funds represent a liability of the Company for repayment either after a specified period or upon satisfaction of certain credit requirements. These funds also represent a source of non-investor supplied capital, and must therefore be deducted from the Rate Base calculation. Both the Company and the Consumer Advocate adopted $1,869,853 as the appropriate amount for Customer Deposits. Upon reviewing the record, the panel also concluded that $1,869,853 was the proper and appropriate forecasted amount to include in Rate Base for Customer Deposits.

V(a)15. ACCRUED INTEREST ON CUSTOMER DEPOSITS

Pursuant to the rules of the Authority, interest on Customer Deposits is refunded to the customer along with the security deposit after a specified period when creditworthiness has been demonstrated.[37] Because the Interest on Customer Deposits is recognized as an expense in computing Net Operating Income, the accrued interest that has not been paid out should be treated as a deduction to Rate Base. Both the Company and the Consumer Advocate adopted $794,102 as the appropriate amount for Accrued Interest on Customer Deposits. The panel also concluded that $794,102 was the appropriate forecasted amount to include in Rate Base for Accrued Interest on Customer Deposits.

V(a)16. CALCULATION OF RATE BASE

After considering each of the individual components to Rate Base described above, the panel determined that the appropriate amount of Rate Base upon which the Company should be allowed to earn a fair rate of return was $95,297,966, calculated as illustrated in the following table.

[37] Tenn Comp R & Regs 1220-4-5-14

COMPARATIVE RATE BASE CALCULATIONS

	Company Original[38]	Consumer Advocate[39]	Company Revised[40]	Authority
Additions:				
Plant in Service	$164,561,353	$164,561,353	$164,561,353	$164,561,353
CWIP	3,544,977	3,544,977	3,544,977	3,544,977
Materials and Supplies	170,409	170,409	170,409	170,409
Gas Inventories	14,193,526	14,193,526	14,193,526	14,193,526
Prepayments	20,358	20,358	20,358	20,358
Other Accounts Receivable	57,547	57,547	57,547	57,547
Deferred Rate Case Expense	250,000	0	250,000	250,000
Lead/Lag Study	1,633,410	1,258,312	1,542,309	1,367,164
Total Additions	**$184,431,580**	**$183,806,482**	**$184,340,479**	**$184,165,334**
Deductions:				
Accumulated Depreciation	$71,307,914	$71,307,914	$71,307,914	$71,307,914
Accumulated Deferred FIT	12,012,158	12,012,158	12,012,158	12,012,158
Customer Advances	286,394	286,394	286,394	286,394
Contributions in Aid of Const.	2,161,125	2,161,125	2,161,125	2,161,125
Reserve for Uncollectibles	435,822	435,822	435,822	435,822
Customer Deposits	1,869,853	1,869,853	1,869,853	1,869,853
Accrued Int on Cust Deposits	794,102	794,102	794,102	794,102
Total Deductions	**$88,867,368**	**$88,867,368**	**$88,867,368**	**$88,867,368**
Rate Base	**$95,564,212**	**$94,939,114**	**$95,473,111**	**$95,297,966**

V(b). NET OPERATING INCOME

Net Operating Income ("NOI") represents the earnings of the Company under present rates that are available after all items of the cost of providing utility service have been considered. In its amended filing, the Company has a forecasted NOI of $6.2 million, while the Consumer Advocate has proposed $7.9 million. A description of each component of NOI, the positions argued by the parties, and the Authority's determination, follow.

[38] Exhibits MJM-3, Schedule 1 and MJM-4, Schedule 2 (January 29, 2004)
[39] Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedules 2 and 3 (July 26, 2004)
[40] Michael J Morley, Pre-Filed Rebuttal Testimony, Exhibits MJM 7-3 and MJM 7-6 (August 16, 2004)

V(b)1. SALE AND TRANSPORTATION OF GAS

Sale and Transportation of Gas represents the gas revenues of the Company at present rates. Both the Company and the Consumer Advocate adopted $92,444,773 as the appropriate amount for the Sale and Transportation of Gas. After reviewing the record, the panel also concluded that $92,444,773 was the appropriate forecasted amount to include in Net Operating Income for the Sales and Transportation of Gas.

V(b)2. GAS COST

Gas Cost represents the cost of gas for wholesale commodity gas purchases, interstate pipeline capacity charges and storage costs that are incurred by the Company. These costs are then billed to the customer separately from base rates through the Company's PGA process The difference between the Company's revenues from the Sale and Transportation of Gas and Gas Cost represents the gross profit margin or base rates of the Company that is used to cover all other costs.

The Company forecasted $63,221,551 of Gas Costs in both its original and amended filings. The Consumer Advocate made an adjustment of $2,360,317 in reducing Gas Cost to $60,861,234. According to the Consumer Advocate, the Company has reported a $2 4 million profit which it has failed to reflect in this rate case.[41]

The Consumer Advocate stated that CGC's marketing affiliate, Sequent Energy Management ("SEM" or "Sequent"), markets CGC's slack gas storage and pipeline capacity assets when those assets are not first needed by CGC's customers. Sequent then shares in the gross profit on a 50-50 basis with CGC's customers in accordance with CGC's tariff. Nevertheless, the Consumer Advocate asserted that, after allocation of Sequent's overhead costs to CGC, these transactions actually result in a net loss that is paid for by CGC's customers.

[41] Daniel W McCormac, Pre-Filed Direct Testimony, pp 11-12 (July 26, 2004)

To illustrate its point, the Consumer Advocate pointed out that on February 27, 2004, CGC filed a refund of the $2,360,317 gross profit earned by Sequent using CGC's gas storage and pipeline capacity assets for the 12 months ended December 31, 2003 In accordance with CGC's tariff, 50% of the $2,360,317, or $1,180,158, was refunded to CGC's customers with the balance retained by the Company as an incentive to market these assets. The Consumer Advocate further pointed out, however, that Sequent was imposing an economic loss on CGC for Sequent's discretionary gas marketing activities. According to Consumer Advocate witness Dr. Steve Brown, Sequent was only sharing approximately $1.2 million with CGC's customers while imposing incremental costs to CGC of over $2.0 million to generate this revenue, thereby resulting in an economic loss to CGC and its customers.[42]

The Consumer Advocate asserted that consumers should get the benefit for the entire $2,360,317 and proposed this as an adjustment to the cost of gas. The Consumer Advocate pointed out that CGC's customers were already paying 100% of the cost for these gas storage and pipeline capacity assets, and that 100% from the benefits of these sales should have flowed back to them.

The Company stated that the $2.027 million cost referred to by the Consumer Advocate was actually additional profit that Sequent shared with CGC.[43] As such, Company witness Michael Morley testified that this was not a direct cost transferred from Sequent to CGC as alleged by the Consumer Advocate, but instead was a sharing of the proceeds from the sale of gas inventory.[44]

At the Hearing, the Consumer Advocate shifted its position on this issue from one of asserting that Sequent was causing economic loss to the Company's customers to one of

[42] Dr Steve Brown, Pre-Filed Direct Testimony, pp 55-75 (July 26, 2004)
[43] Michael J Morley, Pre-Filed Rebuttal Testimony, p 13 (August 16, 2004)
[44] Transcript of Proceedings, v III, p 23 (August 24, 2004)

questioning whether the 50-50 sharing on these types of transactions is appropriate. However, Consumer Advocate witness Daniel W. McCormac admitted that the question of 50-50 sharing and the selection of an affiliate asset manager by the Company was not a base rate issue to be considered within the context of a rate case.[45]

After reviewing the record on this issue, the panel unanimously rejected the Consumer Advocate's proposal to remove $2,360,317 from the Company's Gas Cost and instead voted to include $63,221,551 as the appropriate amount to include in Net Operating Income for Gas Cost.[46]

V(b)3. OTHER REVENUES

Other Revenues represent revenues that the Company indirectly collects which are not necessarily involved in providing gas service. For example, discounts that are forfeited by the customers who do not promptly pay their bills are included in Other Revenues. Both the Company and the Consumer Advocate adopted $973,248 as the appropriate amount for Other Revenues. After its own investigation, the panel also concluded that $973,248 was the proper and appropriate forecasted amount to include in Net Operating Income for Other Revenues.

V(b)4. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for Funds Used During Construction ("AFUDC") is not a revenue item, but represents a reduction, or capitalization, of interest expense and equity costs that the Company incurs on projects taking more than thirty (30) days to complete. Both the Company and the Consumer Advocate adopted $142,441 as the appropriate amount for AFUDC. After its review

[45] Transcript of Proceedings, v VIII, pp 53-55 (August 25, 2004)

[46] During deliberations, Director Tate suggested opening a docket for all gas utilities and interested parties to comment on the issue of management of idle assets, with the possibility of pursuing that issue in a rulemaking proceeding

of the record, the panel also concluded that $142,441 was the appropriate forecasted amount to include in Net Operating Income for AFUDC.

V(b)5. SALARIES AND WAGES

Salaries and Wages represent the direct labor and benefit expenses of the Company's employees in Chattanooga. The Company originally calculated $2,971,581 in Salaries and Wages in its initial filing, but later amended this amount to $2,889,643. The Consumer Advocate adjusted the Company's original forecast by $302,000 and asserted that the Company overstated the number of employees needed in the attrition period by approximately ten percent (10%).[47]

According to the Consumer Advocate, the Company reduced the number of employees following the Company's last rate case but increased that number again in 2003 prior to the filing of this case.[48] Based on this information, the Consumer Advocate alleged that the Company was manipulating the number of employees in order to inflate its revenue requirement.

The Company responded by explaining that the reduction in CGC employees in 1999 was the result of a Company initiative to outsource a majority of its meter reading functions. However, a subsequent study done in 2002 determined that in-house meter reading was more efficient. The Company then increased the number of CGC meter readers from four in December 2002 to ten in December 2003. Further, the Company asserted that a certain number of full-time equivalent ("FTE") employees were necessary to operate CGC's business, and that this number included not only actual employees of CGC but the cost of the outsourced positions as well.[49] The Company presented its historical analysis of the level of FTEs, which showed that the level of FTEs (actual physical employees and outsourced positions) remained consistent from

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[47] Daniel W McCormac, Pre-Filed Direct Testimony, p 8 (July 26, 2004)
[48] Michael D Chrysler, Pre-Filed Direct Testimony, Exhibit MDC EL 1 (July 26, 2004)
[49] Michael J Morley, Pre-Filed Rebuttal Testimony, pp 11-12 (August 16, 2004)

1999 through the attrition period.[50] Finally, the Company stated that it has no plans to eliminate any positions following the conclusion of this rate case.[51] In response to the Company's statements, the Consumer Advocate accepted the Company's forecast.[52]

In its rebuttal testimony, the Company proposed a further adjustment of $81,942 to reduce Salary and Wages for updated payroll information.[53] At the Hearing, the Consumer Advocate witness, Mr. McCormac, agreed with this adjustment.[54]

After reviewing the record on this issue, the panel unanimously rejected the Consumer Advocate's proposal to remove $302,000 from the Company's Salary and Wage Expense. The Consumer Advocate accepted the Company's proposal to adjust Salary and Wages by $81,942 for updated payroll information, and after review, the panel also agreed that this adjustment was appropriate. As a result of this adjustment, the panel approved $2,889,643 as the appropriate amount to include in Net Operating Income for Salaries and Wages.

V(b)6. STORAGE EXPENSE

Storage Expense represents the costs, other than labor and gas, incurred in operating and maintaining the Company's gas storage assets. The Company owns a liquefied natural gas ("LNG") facility that is included in the Rate Base calculation under Plant in Service. The LNG facility cools natural gas to a very low temperature until it is converted into a liquid state. The liquefied gas is then stored until needed, at which time it is heated and vaporized back into a gaseous state. This process makes it efficient to store large quantities of natural gas in a relatively small containment area. The cost of operating and maintaining the LNG facility is accounted for as Storage Expense.

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[50] Michael J Morley, Pre-Filed Rebuttal Testimony, p 11 and Exhibit MJM 2-1 (August 16, 2004)
[51] Transcript of Proceedings, v III, p 24 (August 24, 2004).
[52] Transcript of Proceedings, v VII, p 92 (August 25, 2004)
[53] Michael J Morley, Pre-Filed Rebuttal Testimony, Exhibit MJM 2-2 (August 16, 2004)
[54] Transcript of Proceedings, v VIII, p 8 (August 25, 2004).

Both the Company and the Consumer Advocate adopted $521,352 as the appropriate amount for Storage Expense. After its review of the record, the panel concluded that $521,352 was the appropriate forecasted amount to include in Net Operating Income for Storage Expense.

V(b)7. DISTRIBUTION EXPENSE

Distribution Expense relates to costs incurred in operating and maintaining the Company's gas distribution system. Some examples of items that would be classified as Distribution Expense would include expenses relating to dispatching, metering, and maintenance of the Company's mains and service lines. Both the Company and the Consumer Advocate adopted $1,153,546 as the appropriate amount for Distribution Expense. After reviewing the record, the panel concluded that $1,153,546 was the appropriate forecasted amount to include in Net Operating Income for Distribution Expense.

V(b)8. CUSTOMER ACCOUNTS EXPENSE

Customer Accounts Expense relates to costs incurred, excluding labor, in billing and collecting amounts owed by Company customers. Some examples of items that would be classified as Customer Accounts Expense would include meter reading, cashiers, and collection expenses. Both the Company and the Consumer Advocate adopted $48,447 as the appropriate amount for Customer Accounts Expense. After its review of the record, the panel also concluded that $48,447 was the proper and appropriate forecasted amount to include in Net Operating Income for Customer Accounts Expense.

V(b)9. UNCOLLECTIBLE EXPENSE

Uncollectible expenses recognize the Company's annual provision for amounts due from customers that will not be collected. In its initial filing on January 26, 2004, the Company included $963,225 as its forecast for Uncollectible Expense. On March 15, 2004, in TRA

Docket No. 03-00209, the TRA approved a process where all Class A gas utilities such as CGC could recover the gas cost portion of their Uncollectible Expense through the Purchased Gas Adjustment ("PGA"). Since the Company's case was filed before the decision in TRA Docket No. 03-00209, it included the gas cost portion of Uncollectible Expense in its rate filing. These costs must be removed from the Company's case if they are to be collected through the PGA in accordance with the decision in TRA Docket No. 03-00209.

The Consumer Advocate made an adjustment to remove gas cost from Uncollectible Expense in its filing, and stated that $347,249 is now the appropriate amount to use for Uncollectible Expense.[55] In its rebuttal testimony, the Company agreed that an adjustment was in order, but asserted that the correct amount for Uncollectible Expense should be $323,360.[56] At the Hearing, the Consumer Advocate witness, Mr. McCormac, stated that the Consumer Advocate agreed with the Company's calculation of $323,360 for Uncollectible Expense.[57] After its review of the record, the panel also concluded that $323,360 was the appropriate forecasted amount to include in Net Operating Income for Uncollectible Expense.

V(b)10. SALES PROMOTION EXPENSE

Sales Promotion Expense relates to costs incurred, excluding labor, to promote or retain the use of utility services by present or prospective customers. Some examples of items that would be classified as Sales Promotion Expense would include demonstrating expenses, selling expenses, and advertising expenses. Both the Company and the Consumer Advocate adopted $209,654 as the appropriate amount for Sales Promotion Expense. After its review of the record, the panel also concluded that $209,654 was the appropriate forecasted amount to include in Net Operating Income for Sales Promotion Expense.

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[55] Daniel W McCormac, Pre-Filed Direct Testimony, pp 8-9 and Exhibit CAPD-DM, Schedule 8 (July 26, 2004)
[56] *See* Michael J Morley, Pre-Filed Rebuttal Testimony, p 28 (August 16, 2004)
[57] Transcript of Proceedings, v VIII, pp. 60-62 (August 25, 2004)

V(b)11. ADMINISTRATIVE AND GENERAL EXPENSE

Administrative and General ("A&G") Expense relates to costs incurred, excluding payroll, in operating the utility that are not directly chargeable to a particular function. Examples of items that would be classified as A&G Expense include audit and pension expense.

In its initial filing, the Company forecasted $1,434,139 for A&G Expense. The Consumer Advocate began with the Company's forecast and made two adjustments. The Consumer Advocate first made an adjustment of $20,295 for the related pension and benefit expense associated with its Salary and Wage adjustment. The Consumer Advocate next made an adjustment of $100,000 to remove Rate Case Expense. After taking the combined effect of both of these adjustments into account, the Consumer Advocate's forecast for A&G Expense was $1,313,844.

In its Rebuttal Filing, the Company proposed an adjustment to reduce A&G expense by $114,007 from its original filing to reflect changes in post retirement benefits and other payroll benefits brought about by changes in actuarial estimates and benefit plans since the Company filed its case.[58] At the Hearing, the Consumer Advocate stated that it agreed with this adjustment.[59]

Although no adjustment was made in its case, the Consumer Advocate pointed out that CGC's parent company, AGLR, is transferring profit from CGC by retaining operating expense credits of $8.2 million at the parent company rather than distributing them to the operating subsidiaries. According to the Consumer Advocate, this retention overstates CGC's operating expenses.[60]

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[58] Michael J Morley, Pre-Filed Rebuttal Testimony, pp. 34-35 and Exhibit MJM 7-5 (August 16, 2004)
[59] Transcript of Proceedings, v VIII, p 8 (August 25, 2004).
[60] Dr Steve Brown, Pre-Filed Direct Testimony, p 9 (July 26, 2004).

The Company responded that the undistributed $8.2 million transfer credit on the AGLR holding company books was the result of audit findings on the allocation of holding company costs by the Security and Exchange Commission ("SEC") for the thirty-six month period from January 2001 through December 2003. The SEC has now required AGLR to allocate this $8.2 million transfer credit to each of its operating subsidiaries. According to the Company, CGC's total share of this transfer credit is $377,000 representing an annual reduction in expenses of approximately $125,000 per year.[61] At the Hearing, the Company admitted that as a result of the SEC Audit, the test period expenses had been overstated by an average of $125,000.[62]

As explained previously, the panel rejected the Consumer Advocate's proposed adjustment to A&G Expense related to its proposed adjustments for Salaries and Wages Expense and Rate Case Expense. Both the Company and the Consumer Advocate agreed that an adjustment of $114,007 was appropriate to reduce A&G Expense for new information coming to light relating to post retirement benefits and other payroll related benefits, and after its review of the record, the panel agreed with this adjustment. The panel also concluded that an adjustment to reduce A&G Expense by $125,000 to reflect the results of the SEC Audit was appropriate. After making each of these adjustments, the panel concluded that $1,195,132 was the proper and appropriate forecasted amount to include in Net Operating Income for Administrative and General Expense. As a result of concerns about the SEC Audit, the panel also directed the Company to inform the Authority within two (2) weeks of its becoming aware of any future actions of the SEC that involve the financial statements of CGC, AGLR or its affiliates.

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[61] Michael J Morley, Pre-Filed Rebuttal Testimony, pp 24-25 (August 16, 2004)
[62] Transcript of Proceedings, v III, pp 20-21 (August 24, 2004)

V(b)12. CORPORATE ALLOCATIONS

In October 2000, AGLR, the parent company of Chattanooga Gas Company, purchased Virginia Natural Gas ("VNG"). AGLR then formed AGL Services Company ("AGSC") in compliance with the requirements of the Public Utility Holding Company Act ("PUHCA").[63] AGSC provides centralized services for all of the AGLR affiliates including CGC and allocates the cost of providing these services to each affiliate in accordance with PUHCA guidelines. In both its initial and amended filings, the Company included $7,136,452 as its forecasted amount to include in Net Operating Income for Corporate Allocations.

According to the Company, the formation of AGSC provided improved efficiencies and economies of scale, which resulted in lower cost allocations to CGC for shared services of approximately $1,067,606. Instead of allowing all of the allocated cost savings to benefit Chattanooga customers, the Company proposed that it be allowed to charge CGC customers an additional $533,803, representing fifty percent (50%) of the allocated cost savings.

The Consumer Advocate was opposed to this adjustment, and stated that CGC customers should not pay more than the actual costs reflected on CGC's books.[64] As such, the Consumer Advocate eliminated the Company's adjustment for improved efficiencies and only included $6,602,649 as its forecasted amount to include in Net Operating Income for Corporate Allocations.

After reviewing the record on this issue, the panel concluded that $6,602,649 was the appropriate forecasted amount to include in Net Operating Income for Corporate Allocations.

[63] *See* 15 U S C A § 79, *et seq*
[64] Transcript of Proceedings, v III, p 23 (August 24, 2004)

V(b)13. DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation and Amortization Expense represent the systematic recovery of capital invested in assets placed in service by the Company. As Depreciation and Amortization Expenses are recognized, the balance of Accumulated Depreciation is increased in determining the proper level of Rate Base.

Both the Company and the Consumer Advocate adopted $5,194,810 as the appropriate amount for Depreciation Expense. After reviewing the record, the panel concluded that $5,194,810 was the appropriate forecasted amount to include in Net Operating Income for Depreciation Expense.

V(b)14. INTEREST ON CUSTOMER DEPOSITS

Authority rules require gas utilities to accrue interest on Customer Deposits. This interest is then refunded to the customer along with the security deposit after a specified period when credit worthiness has been demonstrated. Both the Company and the Consumer Advocate adopted $112,191 as the appropriate amount for Interest on Customer Deposits. After its review of the record, the panel concluded that $112,191 was the appropriate forecasted amount to include in Net Operating Income for Interest on Customer Deposits.

V(b)15. TAXES OTHER THAN INCOME

Taxes Other Than Income includes Property Taxes, Franchise Taxes, Gross Receipts Taxes, Authority Fees, Payroll Taxes, and Other General Taxes. In its initial filing, the Company included $3,425,744 in its forecast for Taxes Other Than Income. The Consumer Advocate began with the Company's forecast and made an adjustment of $22,226 for the related payroll taxes associated with its Salary and Wage adjustment to compute its forecast of $3,403,518 for Taxes Other Than Income.

In its Amended Filing, the Company made an adjustment of $6,269 from its initial filing for the payroll tax effect of its proposed changes to Salary and Wages. With this change, the Company's new forecast for Taxes Other Than Income is $3,419,475.

As explained earlier, the panel rejected the Consumer Advocate's proposed adjustment to Salaries and Wages and therefore rejected the related adjustment to payroll taxes. Likewise, since the panel accepted the Company's proposed changes to Salaries and Wages, the Company's proposed changes to Taxes Other Than Income for their payroll adjustment of $6,269 were also accepted. The panel therefore concluded that $3,419,475 was the appropriate forecasted amount to include in Net Operating Income for Taxes Other Than Income.

V(b)16. INCOME TAXES

Income Taxes include both the Tennessee Excise Tax and the Federal Income Tax. The Tennessee Excise Tax is a 6.5 percent (6.5%) income tax on the earnings of the Company. The Federal Income Tax is a 35 percent (35%) income tax on the earnings of the Company. After considering all of the previous adjustments, a combined Income Tax forecast of $1,981,475 was calculated. Based upon the revenues and expenditures adopted elsewhere in this Order, the panel approved $1,981,475 as the appropriate forecast amount for Income Taxes.

V(b)17. CALCULATION OF NET OPERATING INCOME

After each of the previous adjustments was taken into account, a Net Operating Income under current rates of $6,687,177 was calculated as follows.

COMPARATIVE NET OPERATING INCOME CALCULATIONS

	Company Original[65]	Consumer Advocate[66]	Company Amended[67]	Authority
Sale & Transportation of Gas	$92,444,773	$92,444,773	$92,444,773	$92,444,773
Less Gas Cost	63,221,551	60,861,234	63,221,551	63,221,551
Net Sale & Transportation of Gas	**$29,223,222**	**$31,583,539**	**$29,223,222**	**$29,223,222**
Other Revenues	973,248	973,248	973,248	973,248
AFUDC	142,441	142,441	142,441	142,441
Net Revenues	**$30,338,911**	**$32,699,228**	**$30,338,911**	**$30,338,911**
Salaries & Wages	$2,971,585	$2,669,585	$2,889,643	$2,889,643
Storage Expense	521,352	521,352	521,352	521,352
Distribution Expense	1,153,546	1,153,546	1,153,546	1,153,546
Customer Accounts Expense	48,447	48,447	48,447	48,447
Uncollectible Expense	963,225	347,249	323,360	323,360
Sales Promotion Expense	209,654	209,654	209,654	209,654
Admn & General Expense	1,434,139	1,313,844	1,320,132	1,195,132
Corporate Allocations	7,136,452	6,602,649	7,136,452	6,602,649
Depr & Amort Expense	5,194,810	5,194,810	5,194,810	5,194,810
Interest on Customer Deposits	112,191	112,191	112,191	112,191
Taxes Other Than Income	3,425,744	3,403,518	3,419,475	3,419,475
Income Taxes	1,480,386	3,185,548	1,811,965	1,981,475
Total Operating Expenses	**$24,651,531**	**$24,762,393**	**$24,141,027**	**$23,651,734**
Net Operating Income	**$5,687,380**	**$7,936,835**	**$6,197,884**	**$6,687,177**

[65] Company Exhibit MJM-1, Schedule 1
[66] Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedules 6 and 8 (July 26, 2004)
[67] Michael J Morley, Pre-Filed Rebuttal Testimony, Exhibits MJM 7-1 and MJM 7-5 (July 26, 2004)

V(c). FAIR RATE OF RETURN

There are three steps to establishing the fair rate of return: (1) determine an appropriate capital structure; (2) determine the cost rates of each component of the capital structure: (i) short-term debt, (ii) long-term debt, (iii) preferred equity, and (iv) common equity; and (3) compute the overall cost of capital using a weighted average of the component rates to account for the proportion of each component.

There is no objective measure of the fair rate of return. Therefore, the TRA must exercise its judgment in making the appropriate determination. The Authority, however, is not without guidance in exercising its judgment. The principle factors that should be used in establishing a rate were set forth by the U.S. Supreme Court in *Bluefield Water Works & Improvement Company v Public Service Commission*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[68]

In *Federal Power Commission v. Hope Natural Gas Company*, the U.S. Supreme Court determined that regulated firms are entitled to a return that is "just and reasonable."[69] The rate a firm is permitted to charge should enable it "to operate successfully, to maintain its financial integrity, to attract capital, and to compensate investors for the risks assumed."[70]

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68 *Bluefield*, 262 U S. at 692-93, *See also Duquesne Light Company v Barasch*, 488 U S 299, 310 (1989)
69 *Hope*, 320 U S at 605
70 *Id*

According to the Court in *Hope*, the general standards to be considered in establishing the fair rate of return for a public utility are financial integrity, capital attraction and setting a return on equity that is commensurate with returns investors could achieve by investing in other enterprises of corresponding risk. The utility's fair rate of return is the minimum return investors expect, or require, in order to make an investment in the utility. The proper level of return on the company's capital, including equity capital, must be commensurate with returns on investment in other enterprises having corresponding risk.

Additionally, a utility is only entitled to a return on a plant that is actually serving ratepayers. This principle was stated by the U.S. Supreme Court in *Denver Union Stock Yard Company v United States*:

> The utility is entitled to rates, not per se excessive and extortionate, sufficient to yield a reasonable rate of return upon the value of property used, at the time it is being used, to render the service. But it is not entitled to have included any property not used and useful for that purpose.[71]

Thus, pursuant to the *Hope*, *Bluefield* and *Denver Union* decisions, the general standards to be considered in establishing a fair rate of return for a public utility are financial integrity, capital attraction and setting a return on equity that is commensurate with returns investors could achieve by investing in other enterprises of corresponding risk. The utility's fair rate of return is the minimum return investors expect, or require, in order to make an investment in the utility.

[71] *Denver Union Stock Yard Co v United States*, 304 U S 470, 475, 58 S Ct 990 (1938)

V(c)1. CAPITAL STRUCTURE

The Company recommended that the Authority adopt a "stand-alone" approach, which uses CGC's own capital structure and ignores the parent-subsidiary relationship between AGLR and CGC. However, the Company did not follow this approach consistently, using AGLR's level of preferred equity in its proposed capital structure.[72]

CGC witness Dr. Roger Morin listed 15 comparable companies in the natural gas industry and provided information on many other electric utilities and combination gas and electric utilities. In contrast, Consumer Advocate witness Dr. Steve Brown listed 10 comparable companies, excluding five of the companies listed by Dr. Morin that he determined were not comparable.[73]

CGC proposed a capital structure based on comparable companies and consisting of 49% common equity and 51% debt,[74] combined with its own short-term capital and preferred equity needs. The proposed capital structure consisted of 4.3% short-term debt, 40.10% long-term debt, 46.90% common equity, and 8.7% preferred equity.[75] The Consumer Advocate proposed a capital structure that excludes preferred equity and consists of 12.90% short-term debt, 44.6% long-term debt, 0.0% preferred equity, and 42.5% common equity.[76]

CGC proposed a cost rate for short-term debt of 2.69%, a cost rate for long-term debt of 6.74%, a cost rate for preferred equity of 8.54%, and a return on equity of 11.25%, resulting in an overall cost of capital of 8.84%. In contrast, the Consumer Advocate proposed a 1.26% cost rate for short-term debt, a 6.74% cost for long-term debt, a 0% cost for preferred equity, and an

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[72] Transcript of Proceedings, v III, p 15 (August 24, 2004)

[73] Dr Brown excluded the following companies AGLR, because it is the parent of CGC and would bias the capital structure, Amerigas, because it only sells propane and it is 100% owned by UGI, UGI, because it is an international energy conglomerate with only 17% of its revenues coming from gas sales in the United States, Energen, because it has not been through a rate case since 1982, and Southern Union, because it is a pipeline company

[74] Dr Roger A Morin, Pre-Filed Direct Testimony, p. 4 and Exhibit RAM-9 (January 26, 2004)

[75] Exhibit MJM-4, Schedule 1 (January 29, 2004)

[76] Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM Schedule 12 (July 26, 2004)

8.35% return on equity, resulting in a 6.72% overall cost of capital. The following table illustrates the capital structures proposed by the Company and the Consumer Advocate:

SUMMARY OF ESTIMATED COST OF CAPITAL USING COMPARABLE COMPANIES							
Line No.	**Capital Structure Component**	**Ratio**		**Cost Rate**		**Weighted Average Cost**	
		CGC	**CAPD**	**CGC**	**CAPD**	**CGC**	**CAPD**
1	**Short-term debt**	4.30%	12.90%	2.69%	1.26%	0.12%	0.16%
2	**Long-term debt**	40.10%	44.60%	6.74%	6.74%	2.70%	3.01%
3	**Preferred stock**	8.70%	0.00%	8.54%	0.00%	0.74%	0.00%
4	**Total Debt**	53.10%	57.50%			3.56%	3.17%
5	**Common equity**	46.90%	42.50%	**11.25%**	**8.35%**	5.28%	3.55%
6	**Total Capitalization**	100.00%	100.00%			**8.84%**	**6.72%**

Sources Exhibit MJM-4, Schedule 1.
Exhibit CAPD-DM, Schedule 12.

There is no single recipe for the appropriate capital structure. However, since CGC is not an independent entity[77] and all comparable companies are larger in size than CGC, comparable companies will produce average numbers that are biased upward. At the same time, due to their size and diversification of operations, comparable companies will have a lower risk than smaller companies like CGC. Therefore, the capital structure of comparable companies will not necessarily mirror the capital structure of CGC, but will mirror the capital structure of AGLR.

In this proceeding, even though Dr. Brown stated that the use of the double leverage theory would be appropriate,[78] he proposed to use comparable companies instead of using the parent-subsidiary relationship in determining the appropriate capital structure for CGC. Dr.

[77] This decision is consistent with the Authority's finding in Docket No 97-00982 that CGC is not an independent company See *In re Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff*, Docket No 97-00982, *Order*, p 50 (October 7, 1998)
[78] Dr Steve Brown, Pre-Filed Direct Testimony, p 46 (July 26, 2004) and Transcript of Proceedings, v V, p 22 (August 25, 2004)

Brown defines the double leverage theory as "set[ting] the subsidiary's utility rates by determining the parent's equity cost and debt cost, and then us[ing] that total capital cost as the subsidiary's capital cost."[79] The panel found that Dr. Brown's definition of double leverage was not consistent with the standard textbook definition. The double leverage theory suggested instead that the subsidiary's cost of equity should be set equal to the overall weighted cost of capital of the parent. In contrast to Dr. Brown, Dr. Morin stated, "this approach has been largely abandoned in view of its serious conceptual and practical limitations and violations of basic notions of finance, economics, and fairness.... [T]he double leverage approach should not be used in regulatory proceedings and is not currently being used to the best of my knowledge."[80] The Authority disagreed with both expert analyses.

The panel found that AGLR was the appropriate company to reference for determining the cost of equity for CGC and that the capital structure of AGLR was the relevant capital structure for CGC because the parent company's decisions controlled to a great extent the ultimate capital structure and overall cost of capital of its subsidiary. This determination was consistent with the previous rejection of the stand-alone approach and acknowledgment of the parent-subsidiary relationship by the Authority and its predecessor, the Tennessee Public Service Commission ("TPSC").[81] It was also consistent with the decision of the Texas courts that a company's cost of equity is not determined by "the impersonal forces of the financial markets" but rather is determined by "board room decisions made by a parent corporation which controls,

[79] Dr Steve Brown, Pre-Filed Direct Testimony, p 46 (July 26, 2004)

[80] Dr Roger A Morin, Pre-Filed Rebuttal Testimony, p 43 (August 16, 2004)

[81] *See In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, p 17 (July 3, 1985) *See also In re Earnings Investigation of United Telephone – Southeast, Inc*, Docket No 93-04818, *Petition of United Telephone-Southeast, Inc to Extend for One Year its Participation Under the Existing Regulatory Reform Plan,* Docket No 94-00388, and *Petition of United Telephone-Southeast, Inc for Conditional Election for Alternative Regulation,* Docket No 94-00389, *Order*, pp 5-6 (December 30, 1994)

to a great extent, the ultimate cost of a subsidiary's equity."[82] The Authority and the TSPC have consistently decided that "to ignore the effect of leverage at the parent level would result in the regulated utility's earning more than its cost of capital and would produce a windfall return for [the subsidiary]'s stockholders in excess of the authorized return set by this Commission."[83]

More recently, in another rate case brought by CGC in TRA Docket No. 97-00982, the Authority decided that "AGL is the appropriate company to reference for determining the cost of equity" of CGC.[84] The panel concluded, consistent with the previous decisions of this agency related to double leverage and the use of the parent-subsidiary relationship as a basis for the appropriate capital structure of a subsidiary company, that the ten (10) comparable companies proposed by Dr. Brown represented the appropriate proxy in determining the expected return on equity for AGLR.

As a result, the panel found that AGLR's capital structure was the appropriate capital structure for the determination of CGC's cost of capital. Although the panel did not apply the double leverage theory in this proceeding, adopting the capital structure of the parent was justified because the subsidiary company did not own any debts[85] or sell its stock to the public,[86] allowing the subsidiaries to share in the advantages of the parent-subsidiary relationship as well as in the advantages of having a lower risk associated with the investment in the stock and debt

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[82] *See General Tel Co v Public Utility Com*, 628 S W.2d 832, 837 (Tex App 1982)
[83] *In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, p. 17 (July 3, 1985).
[84] *See In re Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff*, Docket No 97-00982, *Order*, p 50 (October 7, 1998).
[85] Michael J Morley, Pre-Filed Direct Testimony, p 19 (January 26, 2004); *See also* Transcript of Proceedings, v III, p 13 (August 24, 2004)
[86] *See* Transcript of Proceedings, v III p 14, line 7 (August 24, 2004)

issued by the parent.[87] Here, CGC has admitted it has no debt in its name and any financing needs are provided through the debt structure of AGLR consolidated group.[88]

The panel's findings were also based on the expected return on equity realized by comparable natural gas distribution utilities. First, using the comparable companies proposed by Dr. Brown, an average expected return on equity for comparable companies was determined. Since the comparable companies' capital structure was a proxy for AGLR's capital structure, this expected return on equity was the expected return on equity issued by AGLR. Then, the capital structure of AGLR[89] was used as the appropriate capital structure to reference for determining the cost of equity for CGC, and the average return on equity determined for AGLR was used as the expected return on common equity for CGC to determine the overall cost of capital for CGC. This was consistent with previous decisions of the TPSC and the Authority that recognized that the debt and equity capital of the subsidiary was raised by the parent company and not by the subsidiary.

V(c)2. INTEREST RATES

Short-term interest rates have been declining over the past five years, but are expected to rise in the future as the Federal Reserve Bank fights against any possible inflation. However, by all estimates, it is unlikely that the 4% to 6% rates experienced in the late 1990s and the years 2000 and 2001 will reoccur. On June 30, 2004, the Federal Open Market Committee ("FOMC") raised its target for the federal funds rate by 25 basis points to 1.25%. This was the first interest rate hike in four years. On August 10, 2004, the FOMC raised its target for the federal funds rate by 25 basis points to 1.50%. The FOMC found that, even after this action, the stance of

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[87] *In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, p 17 (July 3, 1985)

[88] Michael J Morley, Pre-Filed Direct Testimony, p 19 (January 26, 2004)

[89] The capital structure of AGLR is from Dr Steven Brown, Pre-Filed Direct Testimony, Exhibit CAPD-SB, Schedule 3, page 1 of 11 (July 26, 2004)

monetary policy remains accommodative and, coupled with a robust underlying growth in productivity, is providing ongoing support to economic activity. Although incoming inflation data are somewhat elevated, a portion of the increase in recent months seems to reflect transitory factors.[90] Based on these facts, the panel found that the short-term cost rate of 2.69% was not justified by prevailing economic conditions or by any company-specific data.

Using the 12-month average of 1-month LIBOR rates, 3-month LIBOR rates, 1-month Treasury constant maturity, and 3-month Treasury constant maturity rates, the panel calculated an average short-term interest rate of 1.06%. The panel then applied two adjustments: (1) adjusting this average interest rate by 50 basis points to reflect the recent increases in the FOMC's target rate, and (2) accepting the margin spread proposed by CGC to cover borrowing risk associated with AGL Resources. This two-step adjustment produces a cost of short-term debt of 2.31 percent. The panel found that the cost of long-term debt agreed to by the parties of 6.74% is reasonable in light of the prevailing average interest for a 20-year Treasury constant maturity bonds and the necessary level of compensation for the risk associated with AGLR

V(c)3. RETURN ON COMMON EQUITY

Dr. Morin proposed a rate of return on common equity of 11.25%, based upon a Capital Asset Pricing Model ("CAPM") and an empirical CAPM ("E-CAPM"), Risk Premium analyses, and Discounted Cash Flow ("DCF") analyses performed on a group of natural gas distribution utilities and on a group of investment-grade combination gas and electric utilities. The risk analyses performed were a historical analysis on the natural gas industry, a historical analysis on the electric utility industry as a proxy for the Company's business, and a study of the risk premiums allowed in the natural gas distribution industry. According to Dr. Morin, the Authority should allow CGC the opportunity to earn a return on equity that is: (1) commensurate

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[90] *See* http //federalreserve gov/boarddocs/press/monetary/2004/20040810/default htm

with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.[91]

Dr. Brown used primarily the CAPM model and the DCF analysis. He rejected the use of historical and allowed rates of return on equity, claiming that they were not standard methods used in this arena and that it was not possible to verify the data utilized by Dr. Morin.[92] In his rebuttal testimony, Dr. Morin supplied the sources of the data used in the historical risk premium and in the allowed returns analyses and further stated that these two approaches were standard approaches used in the determination of the appropriate return to allow a utility.[93]

The table below compares the rate of return on equity proposed by CGC and the Consumer Advocate for natural gas utilities under study by each party. The table excludes rates obtained for non-comparable companies such as electric utilities.

PROPOSED EXPECTED RETURN ON EQUITY

MODEL	ROE proposed by CGC without and with flotation costs		ROE proposed by CONSUMER ADVOCATE
CAPM	10.7%	11.0%	7.4%
E-CAPM	11.1%	11.4%	-
Historical risk Premium	11.0%	11.3%	-
Allowed risk premium electric utls	-	11.1%	-
DCF Analysts' Growth	9.7%	9.9%	9.28%
DCF Value Line	11.8%	12.0%	-
DCF Combination Gas & Electric Zacks Growth	9.0%	9.3%	
DCF Combination Gas & Electric Value Line Growth	10.1%	10.3%	
Overall return on equity	**11.0%**	**11.25%**	**8.35%**

Source Dr Morin Direct Testimony, Dr Brown Direct Testimony.

[91] Dr Roger A Morin, Pre-Filed Direct Testimony, pp 9-10 (January 26, 2004)
[92] Dr Steve Brown, Pre-Filed Direct Testimony, pp 84-85 (July 26, 2004)
[93] Dr Roger A Morin, Pre-Filed Rebuttal Testimony, pp. 47-48 (August 16, 2004)

V(c)3a. CAPM ESTIMATES

CGC witness Dr. Morin assumed a risk-free rate of 5.3%; a beta of 0.77 and a market risk premium of 7.0%. For the risk-free asset, Dr. Morin relied on the actual yields on thirty-year Treasury bonds. He stated that long-term rates were the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. The prevailing yield in early December 2003 was 5.3%, as reported in the Value Line Investment Survey for Windows, December 2003 edition.[94]

Dr. Morin further assumed that since CGC was not a publicly-traded company, and since CGC was a relatively small size company, CGC possessed an investment risk profile that was at least as risky as that of the average risk publicly-traded natural distribution utility company. All companies used in this study had a market capitalization above $500 million in order to avoid the well-known thin trading bias.[95]

The beta of 0.77 used by Dr. Morin is based on the average beta for a combination of gas and electric utilities as reported by Value Line instead of using the average beta of 0.73 of 15 comparable natural gas companies as published by Value Line Investment Survey for Windows, December 2003 edition.[96]

Dr. Morin used a 7.0% risk premium based on the results of both forward-looking and historical studies of long-term risk premiums. Using Ibbotson Associates' study, *Stocks, Bonds, Bills, and Inflation, 2003 Yearbook,* he compiled historical return data from 1926 to 2002 and

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[94] Dr Roger A Morin, Pre-Filed Direct Testimony, pp 21-22 (January 26, 2004)
[95] Dr Roger A. Morin, Pre-Filed Direct Testimony, pp 23-24 (January 26, 2004)
[96] Dr Roger A Morin, Pre-Filed Direct Testimony, p. 24 (January 26, 2004) and Exhibit RAM-2

found a risk premium of 6.4% over U.S. Treasury Bonds.[97] However, Dr. Morin used the historical market risk premium over the income component of long-term Treasury bonds rather than over the total return. He asserted that a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicated a prospective market risk premium of 7.0% as well.

Dr. Morin found a cost of common equity of 10.7% using this CAPM model. With flotation costs (the costs to shareholders of issuing common stock) of 5% factored in, this estimate became 11.0%.

Dr. Morin's empirical CAPM (E-CAPM) model produced a return on equity of 11.1% without flotation costs and 11.4% with flotation costs. Dr. Morin stated that the CAPM produced a downward-biased estimate of equity costs for companies with a beta of less than 1.00 and that E-CAPM model relaxed some of the more restrictive assumptions underlying the traditional CAPM model that were responsible for the bias.[98]

Consumer Advocate witness Dr. Brown presented a modified version of the standard CAPM model in which he replaced the risk-free rate in the first term of the equation by the cost of long-term debt, while leaving the second risk-free rate unchanged. Stating that Value Line betas are inflated and "are not standard practice in the financial industry,"[99] Dr. Brown calculated his own betas using raw data published by Yahoo, Lycos, and AOL OnLine. Dr. Brown used a beta of 0.10 and a risk premium of 6.415, which was the difference between the geometric mean return of an index of returns to S&P 500 companies as published by Ibbotson Associates 2003 Yearbook (10.20%) and the geometric mean risk free rate of return of an index of returns for

[97] Dr Roger A Morin, Pre-filed Direct Testimony, p. 24 (January 26, 2004)
[98] Dr Roger A Morin, Pre-Filed Direct Testimony, p 28 (January 26, 2004)
[99] Dr Steve Brown, Pre-Filed Direct Testimony, p 114 (July 26, 2004)

three-month Treasury Bills as published by Ibbotson Associates 2002 Yearbook (3.79%). Dr. Brown's CAPM analysis produced a return on equity of 7.4%.[100]

V(c)3b. HISTORICAL RISK PREMIUM

CGC witness Dr. Morin also calculated a historical risk premium for the natural gas distribution companies using Moody's Natural Gas Distribution Index as an industry proxy.[101] The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Dr. Morin found a return on equity equal to 11.0% without flotation costs and 11.3% with flotation costs. This same calculation applied to a set of electric utilities produced an equity return of 10.9% without flotation costs and 11.2% with flotation costs.[102] Consumer Advocate witness Dr. Brown did not support the use of the historical risk premium analysis.[103]

V(c)3c. ALLOWED RISK PREMIUMS

Using allowed risk premiums together with the current long-term Treasury bond yield of 5.3%, CGC witness Dr. Morin found that a risk premium of 5.8% should be allowed for the average risk natural gas distribution utility, implying a cost of equity of 11.1% for the average risk utility.[104] Consumer Advocate witness Dr. Brown did not support the use of the allowed risk premium analysis.[105]

[100] Dr Steve Brown, Pre-Filed Direct Testimony, pp. 105-113 (July 26, 2004)
[101] Exhibit RAM-3
[102] Dr Roger A Morin, Pre-Filed Direct Testimony, pp 29-30 (January 26, 2004)
[103] Dr Steve Brown, Pre-Filed Direct Testimony, p. 84 (July 26, 2004)
[104] Dr Roger A Morin, Pre-Filed Direct Testimony, p 32 (January 26, 2004)
[105] Dr Steve Brown, Pre-Filed Direct Testimony, p 84 (July 26, 2004)

V(c)3d. DCF ESTIMATES

CGC witness Dr. Morin's DCF analysis was applied to a group of natural gas distribution utilities and to a group of investment-grade combination gas and electric utilities. In that analysis, Dr. Morin used the Analysts' Growth Forecasts and Value Line Growth.[106]

For the natural gas local distribution companies, Dr. Morin found returns of equity that varied from 9.7% to 11.8% without flotation costs and from 9.9% to 12.0% with flotation costs. Dr. Morin's DCF analysis used dividend growth rates from Value Line[107] and excluded the companies Amerigas and Southern Union.[108] Dr. Morin's DCF analysis multiplied the spot dividend yield by one plus the expected growth rate (1 + g). Dr. Morin asserted that "[s]ince the stock price fully reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity returns also reflect the actual timing of quarterly dividends."[109] Thus, Dr. Morin adjusted the stock yields for quarterly compounding.

Consumer Advocate witness Dr. Brown's DCF analysis excluded the companies UGI, Energen, AGLR, Amerigas and Southern Union; relied on the average of the projected growth rates by Zack's in Exhibit RAM-5 and by Yahoo; averaged the current dividend yields from Value Line and MorningStar; and excluded the "expected dividend yield" shown in column 4 of Exhibits RAM-5 and RAM-6. Dr. Brown proposed a DCF equity dividend yield of 9.28% (which equals the sum of the dividend yield and the growth rate and does not include the effect of compounding its rate of return) compared to Dr. Morin's proposed yield of 9.9%.

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106 Dr. Roger A Morin, Pre-Filed Direct Testimony, p 36 (January 26, 2004)
107 Exhibit RAM-6
108 Exhibits RAM-2 and RAM-9
109 Dr Roger A Morin, Pre-Filed Rebuttal Testimony, p 13 (August 16, 2004)

In Dr. Brown's opinion, Value Line's projections were not credible and should not be used to determine the rate of return on equity.[110] Dr. Brown presented data analysis to show that Value Line has always over-forecasted AGLR's dividends and has over-forecasted AGLR's earnings four out of five times.[111]

V(c)4. ANALYSIS OF COST OF CAPITAL RATES

V(c)4a. CAPM ANALYSIS

CGC witness Dr. Morin used Value Line, or so-called adjusted betas, to obtain the beta proxy for CGC. Since Dr. Morin basically used the sample average utility beta as his estimate of the beta for CGC and did not apply any further adjustment to the average of Value Line betas, the tendency of the beta will regress to that same sample average utility beta. Therefore, the panel accepted the average beta calculated from Dr. Brown's comparable companies, but rejected Dr. Brown's raw betas from Yahoo, Lycos, and AOL OnLine because they were not adjusted.

The TPSC found in the past that there was merit in either using the rate of short-term T-bills or the rate of long-term Treasury bonds as the appropriate risk free rate to apply to the CAPM calculations.[112] The panel found that both short-term T-bills and long-term Treasury bonds were indeed backed in the same manner by the federal government. However, the panel agreed with CGC witness Dr. Morin that the yield on 90-day Treasury Bills was more volatile than the yield on long-term Treasury bonds as it was expected to change for each short period. The panel believed that the rates of long-term Treasury bonds were the appropriate proxy for the

[110] Dr Steve Brown, Pre-Filed Direct Testimony, p 96 (July 26, 2004)
[111] Dr Steve Brown, Pre-Filed Direct Testimony, Exhibit CAPD-SB, Schedule 23, p 2 (July 26, 2004)
[112] *See In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, p 7 (July 3, 1985)

risk-free rate in the CAPM calculations. The TPSC accepted the use of long-term instrument rates as proxy for risk-free rate in previous proceedings.[113]

In contrast, Consumer Advocate witness Dr. Brown asserted that the appropriate proxy for the risk-free rate of return was the yield on 90-day Treasury bills, rather than the yield on long-term Treasury bonds. However, in his version of the CAPM model, Dr. Brown replaced the risk-free return by the cost of long-term debt of 6.74%. The panel found that this obvious inconsistency rendered Dr. Brown's CAPM analysis ineffective. Further, in his calculation of the risk premium, Dr. Brown used the geometric mean to derive the risk premium.[114] The panel found that Dr. Morin presented sufficient evidence to rebut Dr. Brown's use of the geometric averages. The literature discussed by Dr. Morin addressing the issue showed that arithmetic rather than geometric averages were most appropriate in measuring expected return using a historical return data.[115]

In February 2002, the Treasury Department announced that it would no longer issue 30-year bonds. The lack of new bonds, among other reasons, rendered the rate on 30-year Treasury bonds an inappropriate measure for pension purposes.[116] Therefore, the panel found that the use of the latest rate for the 20-year Treasury Constant Maturity Rate was more appropriate. As of July 1, 2004, this rate was 5.24%. CGC witness Dr. Morin testified that the Authority should use the most recent rate publicly available at the time the decision is issued.[117] The panel agreed with Dr. Morin.

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[113] *See In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, p 7 (July 3, 1985)
[114] Dr Steve Brown, Pre-Filed Direct Testimony, p 110 (July 26, 2004)
[115] Dr Roger A Morin, Pre-Filed Rebuttal Testimony, pp 22-27 (August 16, 2004)
[116] *See* http //www mellon com/hris/pdf/fyi_10_20_03c pdf
[117] Transcript of Proceedings, v V, p 4 (August 25, 2004)

In TRA Docket No. 97-00982, the Authority rejected the use of compounding theory in the DCF analysis.[118] For that reason, the panel also adjusted Dr. Morin's determination of the market risk premium of 7.0%. Using the expected return of 12.1% and a risk-free rate of 5.24% produces a market risk premium of 6.76%.[119] Therefore, the panel accepted the use of the CAPM analysis presented by Dr. Morin. The result of such analysis was as follows:

$K = R_F + \beta\ (R_M - R_F) = 5.24\% + 0.73(12.1\% - 5.24\%) = 10.17\%$ as CAPM estimate of cost of common equity. The panel did not adopt the addition of flotation costs, as discussed below.

V(c)4b. EMPIRICAL CAPM (E-CAPM) ESTIMATES

Although Dr. Morin explained his reasons for using E-CAPM, the panel did not find that E-CAPM was a universally accepted approach to determine the cost of equity. An implicit term in the second term on the right-hand side of Dr. Morin's equation was the market beta (β_m) of one. Inserting the market beta (β_m) in the second term of Dr. Morin's equation on page 28 of his direct testimony,[120] the two risk premium terms in the equation can be written as:

$0.25\ \beta_m\ (R_m - R_f) + 0.75\ \beta_{CGC}(R_m - R_f)$.

This term can be rewritten as:

$(0.25\ \beta_m + 0.75\ \beta_{CGC})(R_m - R_f) = [(0.25 \times 1.0) + 0.75 \times 0.77](7\%)$ since $\beta_m = 1$.

By placing a 75% weight on the adjusted beta of 0.77 for CGC and a 25% weight on the market beta of one, the E-CAPM arrives at an inflated beta for CGC of 0.8275. In other words, a mean adjusted beta of 0.77 has become 0.8275 in the E-CAPM, thus inflating beta by 7.5%. Thus, the panel concluded that the E-CAPM was merely another method to further inflate an

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[118] *See In re Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff*, Docket No 97-00982, *Order*, p 50 (October 7, 1998)
[119] *See* Dr Roger A Morin, Pre-Filed Direct Testimony, p. 26 (January 26, 2004), where he determined 12 1% as the expected return before compounding
[120] Dr Roger A Morin, Pre-Filed Direct Testimony, p 28 (January 26, 2004)

already adjusted beta estimate for CGC and, therefore, rejected Dr. Morin's empirical CAPM analysis.

V(c)4c. DCF ANALYSIS

The simplified DCF cost of equity is defined as the sum of the dividend yield and a growth rate. CGC witness Dr. Morin used a variant of the "quarterly dividend model" and Consumer Advocate witness Dr. Brown used the annual model. Dr. Morin's model was based on the assumption that dividends paid quarterly are worth more to investors than the regular annual lump-sum payment assumed in the DCF annual model, and that the cost of equity should be increased to reflect this increased value.[121]

Dr. Morin's DCF analysis was previously rejected by the Authority in TRA Docket No. 97-00982 when the panel rejected Dr. Brown's compounding theory.[122] For this very reason, the TRA corrected Dr. Morin's DCF analysis for natural gas distribution companies as reflected in Exhibits RAM-5 and RAM-6 to find the expected return on equity of 9.43% and 11.22% for the 10 comparable companies retained by Dr. Brown. Dr. Morin's DCF analysis was corrected by removing the compounding effects, reducing the number of comparable companies to the 10 companies retained, and removing any flotation costs. In addition, the panel did not accept the use of non-comparable companies such as electric utilities and combination gas and electric utilities. The panel approved these corrected DCF results for comparable natural gas companies and the DCF analysis of Dr. Brown, which supplemented Dr. Morin's analysis with additional growth rates from Yahoo, averaged all the growth rates, averaged the current dividend yields from Value Line and MorningStar, and removed the compounding effects. Therefore, the panel accepted the recommended expected return on equity by Dr. Brown of 9.28%.

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[121] Dr Roger A Morin, Pre-Filed Rebuttal testimony, pp 12-14 (August 16, 2004)

[122] *See In re Petition of Chattanooga Gas Company to Place Into Effect a Revised Natural Gas Tariff*, Docket No 97-00982, *Order*, p 50 (October 7, 1998)

V(c)4d. HISTORICAL RISK PREMIUM

Dr. Morin used an historical risk premium for the natural gas distribution utility industry using Moodys' Natural Gas Distribution Index as an industry proxy.[123] The average risk premium over the period 1955 to 2001 was 5.66%. Using the risk-free rate of 5.24% determined above, the implied cost of equity for an average natural gas utility was 10.90%. Dr Brown concluded that this method was not a standard method and that it was impossible to crosscheck and verify because it was not based on the comparable natural gas distribution companies used in this proceedings but rather "based on a natural gas company index with unknown members for the past 50 years."[124] The panel found that the Moody's Natural Gas Distribution Stock Index could be easily verified and that this approach did not have to be based on comparable companies. In addition, the panel found that using long-time series data provided stable data, which produced the best possible estimates. Therefore, the panel adopted the historical risk premium analysis and found that the adjusted expected return on equity was 10.9%.

V(c)4e. ALLOWED RISK PREMIUMS

CGC witness Dr. Morin advocated the usage of an allowed risk premium methodology to value equity. Pursuant to this methodology, Dr. Morin used the historical risk premiums implied in the returns on equity allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield.[125] Dr. Morin used a regression analysis to show that there was a clear inverse relationship between the allowed risk premiums and interest rates.[126] This analysis produced an implied cost of equity of 11.1% for an average natural gas distribution utility.

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[123] *See* Exhibit RAM-3

[124] Dr Steve Brown, Pre-Filed Direct Testimony, p 85 (July 26, 2004)

[125] Dr Roger A Morin, Pre-Filed Direct Testimony, p 30 (January 26, 2004)

[126] Dr Roger A Morin, Pre-Filed Direct Testimony, pp 31-32 (January 26, 2004)

The panel rejected this approach for the following reasons. First, the data used to perform the analysis could not be verified. Dr. Morin stated that his sample was drawn from rulings made by regulatory commissions over the last decade determining returns of equity.[127] Dr. Morin then statistically compared these allowed returns to contemporaneous T-Bill yields. However, the chosen samples may have biased the results. For example, because rate cases generally do not occur at regular intervals, if several rate cases are decided at the same time, the economic conditions at that time may be disproportionately represented in the final results. In addition, there was no showing that the purported relationship between the allowed returns and yields held over a long time period. Finally, the panel found that this methodology was not within the mainstream of equity valuation techniques.[128] Indeed, Dr. Morin was the first witness in a rate case before the Authority to propose the allowed risk premium methodology. Given the lack of historical usage of the methodology, coupled with the inability to verify the data used in his analysis, the panel concluded that Dr. Morin's allowed risk premium methodology should be rejected.

V(c)4f. FLOTATION COSTS

In his analysis, CGC witness Dr. Morin added 5% to the cost of equity for the costs of issuing new stock. In prior dockets, the TPSC found that no adjustment for these "flotation costs" was necessary because the companies involved did not anticipate any new financing and, therefore, the ratepayers should not be required to supply an additional return to cover the costs of issuing new stock and the effects of market pressure which would not occur.[129]

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[127] Dr Roger A Morin, Pre-Filed Direct Testimony, p 30 (January 26, 2004)
[128] *See* Dr Steve Brown, Pre-Filed Direct Testimony, p 84 (July 26, 2004)
[129] *See In re Petition of Tennessee-American Water Company to Place Into Effect a Revised Tariff*, Docket Nos U-83-7226 and U-85-7338, *Order*, pp 24-25 (July 3, 1985)

In this docket, CGC did not produce any evidence that its parent company, AGLR, will issue any new stock during the rate-effective period. In response to a question about an estimate on a new stock issue for the AGLR for the next five years, the Company responded that "[t]he information provided in this response is not a formal forecast or project. This information has not been presented to or approved by the board of directors. Actual results may vary."[130]

During the hearing, CGC's witnesses were asked questions about the impending acquisition of NUI Corporation by AGLR. None of the witnesses mentioned that AGLR planned to issue new stock during the acquisition.[131]

Based upon the lack of evidence of an impending stock issuance, the panel found that CGC's ratepayers should not be required to pay an additional return to cover the costs of issuing new stock and the effects of market pressure which will not occur. Therefore, the panel rejected the addition of 5% to the cost of equity for the costs of issuing stock.

As a summary, the panel approves an average expected return on equity of 10.20%. This is an average of ROE correcting CGC witness Dr. Morin's CAPM, DCF, and HRP analyses and Consumer Advocate witness Dr. Brown's DCF results.

In conclusion, the Authority approves a capital structure consisting of 16.40 % short-term debt at 2.31% cost; 37.90% of long-term debt at 6.74% cost; 10.20% of preferred equity at 8.54% cost; and 35.50% of common equity at 10.20% return on equity. This capital structure and the associated cost of each capital component produce an overall weighted cost of capital of 7.43%.

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130 *See* Response to TRA Econ #2 Data Request No 2 (May 28, 2004) (proprietary).

131 *See* Transcript of Proceedings, v V, p. 15 (August 25, 2004) This testimony was confirmed by a press release about the acquisition and various presentation materials available from AGLR's website, which pointed to 100% cash funding of the transaction in addition to assuming NUI Corporation's equity and debt *See* http //phx corporate-ir net/phoenix zhtml?c=79511&p=irol-newstext&t=Regular&id=591218& and http //media corporate-ir net/media_files/irol/79/79511/presentations/071504 ppt

Capital Structure and Cost of Capital Proposed by the Parties and Adopted by the TRA

SUMMARY OF ESTIMATED COST OF CAPITAL										
Line No.	**Capital Structure Component**	**Ratio**			**Cost Rate**			**Weighted Average Cost**		
		CGC	CAPD	**TRA**	CGC	CAPD	**TRA**	CGC	CAPD	**TRA**
1	**Short-term debt**	4 3%	12 9%	**16.4%**	2 69%	1 26%	**2.31%**	0 12%	0 16%	**0.38%**
2	**Long-term debt**	40 1%	44 6%	**37.9%**	6 74%	6 74%	**6.74%**	2 70%	3 01%	**2.55%**
3	**Preferred stock**	8 7%	0 0%	**10.2%**	8 54%	0 00%	**8.54%**	0 74%	0 00%	**0.87%**
4	**Total Debt**	53 1%	57 5%	**64.5%**				3 56%	3 17%	**3.80%**
5	**Common equity**	46 9%	42 5%	**35.5%**	**11.25%**	**8.35%**	**10.20%**	5 28%	3 55%	**3.62%**
6	**Total Capitalization**	100%	100%	**100%**				**8.84%**	**6.72%**	**7.43%**

Source Exhibit MJM-4 Schedule 1
Exhibit CAPD-DM Schedule 12

The Authority found that this capital structure resulted in a rate of return which will preserve the Company's financial integrity, allow the Company to attract capital and will be commensurate with returns investors could achieve by investing in other enterprises of corresponding risk.

V(d). <u>REVENUE CONVERSION FACTOR</u>

The Revenue Conversion Factor represented the adjustment factor necessary to translate any surplus or deficiency in Net Operating Income (NOI) into a Revenue Deficiency or Surplus that rates will be designed to produce. Both the Company and the Consumer Advocate adopted 1.6521 as the appropriate Revenue Conversion Factor. After its review of the record, the panel concluded that 1.6521 was the appropriate forecasted amount to include as the Revenue Conversion Factor.

V(e). <u>REVENUE DEFICIENCY OR SURPLUS</u>

Based upon the Rate Base, Net Operating Income, Fair Rate of Return, and Revenue Conversion Factor adopted by the panel, the Revenue Deficiency for this case was calculated to be $642,777, as shown below. Therefore, the panel found that the Company needed additional annual revenues in the amount of $642,777 in order to earn a fair return on its investment during the attrition year.

COMPARATIVE REVENUE DEFICIENCY (SURPLUS) CALCULATIONS

	Company Original[132]	**Consumer Advocate**[133]	**Company Amended**[134]	**Authority**
Rate Base	$95,564,212	$94,939,114	$95,473,111	$95,297,966
Operating Income at Current Rates	$5,687,380	$7,936,834	$6,197,884	$6,687,177
Earned Rate of Return	5.95%	8.36%	6.49%	7.02%
Fair Rate of Return	8.84%	6.72%	8.84%	7.43%
Required Operating Income	$8,447,876	$6,379,908	$8,439,823	$7,076,236
Operating Income Deficiency (Surplus)	$2,760,496	$(1,556,927)	$2,241,939	$389,060
Gross Revenue Conversion Factor	1.65213	1.65212	1.65213	1.65213
Revenue Deficiency (Surplus)	**$4,560,699**	**$(2,572,230)**	**$3,703,975**	**$642,777**

V(f). <u>RATE DESIGN</u>

At the Authority Conference on August 30, 2004, the panel unanimously decided to allocate the revenue deficiency evenly to all customer classes except Special Contracts. Based upon a Revenue Deficiency of $642,777, this allocation will produce a 2.00% increase to all

132 Exhibit MJM-1, Schedule 2 (January 29, 2004)

133 Daniel W McCormac, Pre-Filed Direct Testimony, Exhibit CAPD-DM, Schedule 1 (July 26, 2004)

134 Michael J Morley, Pre-Filed Rebuttal Testimony, Exhibit MJM-7-2 (August 16, 2004)

customer classes. The panel also decided that, within each customer class, the Revenue Deficiency should be allocated to volumetric rates only. Monthly customer charges would remain at their present level. In addition, citing the relatively small size of the rate increase and the potential for confusion to customers, the panel rejected the Company's proposal to reduce the rate billing blocks for the Residential and Commercial classes of customers.

The panel also adopted the following tariff adjustments proposed by the Company:

- **A proposal to change to Therm billing for all customer classes**. The Company will be allowed to bill customers in Therm or Dekatherm (10 Therms) units, as opposed to its current billing system of One Hundred cubic feet (Ccf) increments and One Thousand cubic feet (Mcf) increments.[135] This change is consistent with the bills CGC receives from its suppliers and from interstate pipelines.[136]

- **A proposal to change the main and service line extension charges**. The main and service line extension charges will be modified to allow the actual cost of constructing the facilities to be used to determine the required customer contribution when the actual cost is materially different from the amount computed using the average cost factors filed with the TRA.[137]

- **A proposal to allow customers to pay their bills through a third party service provider**. The panel voted to adopt the Company's regulation set forth in the Company's tariff (TRA #2, Sheet 9, Number (9)),[138] which allows customers to use a third-party service provider in the payment of charges due the Company. The third-party service

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[135] Therms and Dekatherms are measures of energy and Ccf and Mcf are measures of volume *See* Steve Lindsey, Pre-Filed Direct Testimony, pp 15-16 (January 26, 2004)

[136] *See* Steve Lindsey, Pre-Filed Direct Testimony, p 15 (January 26, 2004)

[137] *Id* , at 20

[138] TRA #2, Sheet 9, Number (9) reads "As a convenience to the Customer, the Company may at the Customer's option, receive payment through a third party service provider that processes payment by telephone The third party service provider may collect directly from the Customer a separate charge for processing the payment "

provider may collect a separate charge for processing the payment directly from the customer.[139]

- **A proposal for billing suspensions related to seasonal disconnections**. The Company has proposed to provide customers who disconnect on a seasonal basis an option that allows them to avoid the seasonal reconnect charge and the necessity of arranging to have gas service restored before the next heating season. Rather than actually disconnecting service, CGC proposes that billing be suspended for the customer electing the option until usage exceeds 3 Therms during a billing cycle. The customer's meter will continue to be read and the account will remain active in the system but no payment will be required. At the end of the first month that usage exceeds 3 Therms, the account will be moved from suspended status, the customer will be billed the Customer Charge for that month and for total consumption since the account was suspended. The following month the account will be billed in the normal routine.[140]

- **A change in the Company's charges to reconnect service**. CGC also proposed to increase the reconnect charge from $30 to $50 and the seasonal reconnect charge from $30 for residential customers and $45 for commercial customers to $50 for residential and commercial customers.[141]

VI. SETTLEMENT AGREEMENT REGARDING INDUSTRIAL TARIFF

At the hearing on August 24, 2004, CGC and the CMA submitted a summary of a proposed settlement agreement between those parties regarding the Industrial Tariff, which included: (1) modification of the overrun provision; (2) modification of the balancing provision, including the T-1 and T-2 Rate Schedules; (3) creation of a new T-3 Rate Schedule for a new

[139] *See* Steve Lindsey, Pre-Filed Direct Testimony, p 15 (January 26, 2004)
[140] *Id*, at 20-21
[141] Philip G Buchanan, Pre-Filed Direct Testimony, p 4 (January 26, 2004)

low volume rate transportation class; (4) modification of the Experimental Semi-Firm Sales Service Tariff (SF-1); and an agreement by the Company to file a Class Cost of Service Study with its next rate case.[142] The Consumer Advocate did not oppose the settlement agreement.[143] Therefore, the panel approved the Settlement Agreement between the Company and the CMA relating to Industrial Tariff issues other than rates and directed that the tariff language proposed by the Company and the CMA be included in the Company's tariff.

[142] Transcript of Proceedings, v I, Exhibit 1 (August 24, 2004)
[143] Transcript of Proceedings, v III, p 4 (August 24, 2004)

IT IS THEREFORE ORDERED THAT:

1. The rates filed by Chattanooga Gas Company on January 26, 2004 and amended on March 1, 2004 are denied;

2. For purposes of the rates herein, the annual test period shall be the historical test period for the twelve (12) months that ended September 30, 2003, with adjustments for attrition through June 30, 2005;

3. For purposes of the rates herein, the carrying cost of gas inventory shall be recovered through Chattanooga Gas Company's base rates and not through the Purchased Gas Adjustment;

4. For purposes of the rates herein, the rate base is $95,297,966, and the net operating income is $6,687,177;

5. For purposes of the rates herein, a capital structure consisting of 16.40% short-term debt, 37.90% of long-term debt, 10.20% of preferred equity, and 35.50% of common equity is approved;

6. For the purposes of the rates herein, a short-term debt cost of 2.31%, a long-term debt cost of 6.74%, a preferred equity cost rate of 8.54% and a common equity cost rate of 10.20% are approved;

7. For purposes of the rates herein, the capital structure and cost rates indicated above produce a fair rate of return of 7.43%;

8. For purposes of the rates herein, the Revenue Conversion Factor is 1.6521, resulting in a Revenue Deficiency of $642,777, the amount needed for the Company to earn a fair return on its investment during the attrition year;

9. The Revenue Deficiency shall be allocated evenly to all customer classes except Special Contracts and allocated to volumetric rates only. Based upon a Revenue Deficiency of $642,777, this allocation will produce a 2.00% increase to all customer classes except Special Contracts.

10. The Company's request to reduce the rate billing blocks for the Residential and Commercial classes of customers is denied;

11. The Company's request to change to Therm billing for all customer classes is approved;

12. The Company's request to change the main and service line extension charges is approved;

13. The Company's request to allow customers to pay their bills through a third party service provider, as set forth in the tariff as TRA #2, Sheet 9, Number (9), is approved;

14. The Company's request for billing suspensions related to seasonal disconnections is approved;

15. The Company's request to increase charges to reconnect service for residential and business customers is approved;

16. The settlement agreement relating to Industrial Tariff issues other than rates that was negotiated by the Company and the Chattanooga Manufacturers Association, and a summary of which was submitted as Exhibit 1 at the hearing on this matter on August 24, 2004, is approved;

17. The Company's request for a bare steel and cast iron pipe replacement tracker is denied;

18. The Company is directed to inform the Authority within two (2) weeks of its becoming aware of any future actions of the Securities and Exchange Commission that involve the financial statements of Chattanooga Gas Company, AGL Resources or its affiliates;

19. Chattanooga Gas Company is directed to file tariffs with the Authority that are designed to produce an increase of $642,777 in revenue for service rendered and any tariffs necessary to be consistent with this Order;

20. The tariffs shall be filed within ten (10) business days after the date of entry of this Order and shall become effective upon approval of the Authority;

21. Any party aggrieved by the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within fifteen (15) days from the date of this Order; and

22. Any party aggrieved by the Authority's decision in this matter has the right to judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty (60) days from the date of this Order.

Pat Miller

Pat Miller, Chairman

Deborah Taylor Tate

Deborah Taylor Tate, Director

Sara Kyle

Sara Kyle, Director