Before the

TENNESSEE REGULATORY AUTHORITY

IN RE:

PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND CHARGES, COMPREHENSIVE RATE DESIGN PROPOSAL, AND REVISED TARIFF

DOCKET NO. 06-00175

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DIRECT TESTIMONY
OF
MICHAEL D. CHRYSLER

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October 16, 2006

BEFORE THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:

PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND CHARGES, COMPREHENSIVE RATE DESIGN PROPOSAL, AND REVISED TARIFF

DOCKET NO. 06-00175

AFFIDAVIT

I, Michael D. Chrysler, Analyst, for the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

Michael D. Chrysler
MICHAEL D. CHRYSLER

EMILY KNIGHT
NOTARY PUBLIC AT LARGE
DAVIDSON COUNTY, TENN.

Sworn to and subscribed before me
this 16th day of October, 2006.

Emily Knight
NOTARY PUBLIC

My Comm... ...ires SEPT 22, 2007

My commission expires: Sept. 22, 2007

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CAPD Testimony - Michael D. Chrysler

October 16, 2006

Q. Please state your name for the record.

A. My name is Michael D. Chrysler

Q. By whom are you employed and what is your position?

I am employed by the Consumer Advocate and Protection Division ("CAPD") in the Office of the Attorney General for the State of Tennessee as a Regulatory Analyst.

Q. What is your educational and work related background?

A. Please reference attached Appendix A for education and work experience.

Q. What is the purpose for your direct testimony?

A. My testimony will deal with certain operating characteristics of Chattanooga Gas Company ("CGC" or "Company") in Tennessee.

Q. What are your recommendations?

A. I have two recommendations: First, my testimony will indicate that the Company is progressing very slowly in the replacement of their Unprotected Bare Steel/ Cast Iron mains and services in Tennessee. I urge the TRA to accept the Company's accelerated replacement proposal of 10.2 miles/year and completing replacement of their bare steel/cast iron mains by 2014 without the utilization of a cost recovery tracking mechanism.

Second, I recommend the Tennessee Regulatory Authority order the reporting of operational Service Quality Metrics on a regular basis for the Company's Call Center, Field Service, Meter Reading, and Construction functions. Regular reporting of service quality is not as a result of perceived poor service or following numerous consumer complaints regarding service; rather, regular reporting will provide the Company, its consumers, the TRA, and consumer advocates with an objective, statistical representation of Company operations, assuring a continuity of service quality over time. Said another way, how better can a company report a consistent level of quality it provides to customers and interested parties than the regular reporting of operating metrics? This operational reporting is very similar to reporting being adopted by regulators in more states including Georgia[1] and New Jersey[2] where AGL Resources currently reports service metrics to assure service quality. A Tennessee commitment to reporting of operational service metrics on a regular routine would assure Tennessee consumers of a consistent level and commitment to service quality by their service provider.

1. Bare Steel Pipeline Replacement:

Q. Please address the issues regarding completion of Chattanooga Gas Company's bare steel cast iron mains in Tennessee.

A. Chattanooga Gas Company has approximately 82 miles[3] of bare steel cast iron

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[1] Chapter 515-7-7-.04 Georgia Service Quality Standards: Customer Service, Billing, and Metering (CAPD Exhibit MDC-GA)

[2] Elizabethtown (NUI) Service Metrics and Reporting, Letter to New Jersey PSC dated March 31, 2006 (CAPD Exhibit MDC M-2)

[3] Direct Testimony of Richard Lonn, p. 2 in this docket

main that it has been replacing since CGC's 2004 rate filing. In fact, since their last rate case the position of the company and the CAPD's opposition to a PRP Rider have not changed. The same fundamental weaknesses in the PRP tracking mechanism continue with the current filing as it did in 2004: i.e., the responsibility for "capital improvement prudence" shifts from the Company to the TRA and its staff. The difficulties and problems with the PRP can best be explained by those that have the daily responsibility for overseeing the process. As the CAPD did in the last Chattanooga Gas rate case and as well as during the prior ATMOS rate hearing and as detailed below, the complications and "tremendous burden on the Georgia Commission's Staff"[4] and "unsound regulatory policy"[5] are problems inherit with a flawed proposal. CGC has already replaced approximately 70%[6] of its Bare Steel/Cast Iron Main since 1990 without a PRP. Nashville Gas replaced its entire system without a PRP. My testimony will detail the failings of a flawed mechanism and demonstrate to the Authority that a change in regulatory policy at the "eleventh hour" makes no reasonable sense.

Q. Can you explain the nature of your reservations regarding the regulatory appropriateness of the PRP Proposal?

A. Yes. There are several concerns the CAPD has relating to the PRP proposal. In

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[4] TRA Order in Docket 04-00034 p. 16, paragraph 2 (CAPD Exhibit MDC A-1)

[5] TRA Order in Docket 04-00034 ibid, paragraph 3

[6] (CAPD Exhibit MDC A-7), Summary of Bare Steel Cast Iron Mains (271 - 82 = 189 replaced 189/271 = 70%

essence, the mechanism would create an annual rate increase for consumers while removing an incentive for the company to control costs. Under the proposal the mechanism would create a single issue rate case on an annual basis in which included expenses would have to be scrutinized. In addition, implementing the proposal would result in continual monitoring and compliance audits by the TRA Staff. Rather than merely signing off on company figures in-house, detailed audits would be necessary which would include on sight inspections to determine if costs are prudent and whether it is proper that some expenses be shouldered by consumers. As explained later in my testimony, such audits in Georgia have led to contested proceedings over the inclusion of disputed expenses between Staff and AGL. In addition, the CAPD has a procedural concern as to a tracker proceeding. As I stated in my testimony in the 2004 rate case[7]:

> The Consumer Advocate and Protection Division is very concerned about the potential of inflating costs as well as incomplete or unanswered questions on a going-forward basis should the PRP proposal be accepted by the TRA. Formal rate proceeding should allow all interveners the opportunity to study and investigate the appropriateness of costs and management decisions; however, an annual tracking processes may not allow interveners the same access. Should this change in regulatory action take place, it would counter the purposes incurred with the development of Tenn. Code Ann. 65-4-118(2) (A)(B) regarding the development of the Consumer Advocate Division.

Q. Mr. Chrysler, you stated in the 04-00034 case that you were concerned with the potential for a company to inflate costs and attempt the recovery of costs

[7] Michael D. Chrysler Direct Testimony in TRA Docket 04-00034, p.8

other than "replacement costs". Can you share an example from the Georgia PSC Audit Staff developing this concern?

A. Yes. CAPD Exhibit MDC A-3[8] references attempts by AGLC to pass through improper[9] inclusion of Capital and Operation and Maintenance costs through the rider if not discovered by audit staff (page 1, paragraph 1):

> During its second Quarter Audit of Atlanta Gas light Company (AGLC) Pipeline Replacement Rider, Gas Staff discovered that right-of-way charges that the Company had booked as expenses to the rider were actually rate base items. These expenses were to the possible replacement of the East Point Line. In addition, Staff discovered that the Company also intended to book certain anticipated expenses to the Rider though these anticipated charges should be treated as rate base items. The charges in question were not for costs of replacing pipes. Instead, they were related to a pressure improvement agreement between Atlanta Gas Light Company and Southern Natural Gas and capital expenditures for new right-of-ways that will not be used for the pipe replacement program. The Company's funding for these types of items comes through base rates, and the Company was prepared to enter into an agreement with Southern Natural Gas for a pressure improvement program without informing the Commission of its intentions.

Continuing on page 2 paragraph 2:

> The Company continually asserted that if they are not allowed to recover these items through the Rider, then they will simply do pipe-for-pipe replacement without seeking a more prudent method of reducing costs. Staff believes the company has reached a conflict of interest between cost recovery and financial and engineering prudence. There can be a demarcation between cost recoveries, such as rate base and the Pipe Replacement Rider. When a pipe replacement project is being considered, it may have

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[8] Report to the Georgia Public Service Commission in Docket No 8516-U Atlanta Gas Light Company Pipe Replacement Program, dated July 29, 2003 by Tony Wackerly, GPSC Utilities Analyst

[9] The GPSC ruled that the company could recover $6.2 million of the total $12.7 in dispute. Items 2 & 5 on page 5 of Exhibit A-3

elements of both types of recovery, and it is prudent to recognize this demarcation and make the appropriate decision on allocating which costs should be recovered under each mechanism. The Company has failed to understand this line of demarcation between recovery mechanisms by attempting to go forward with this pressure improvement project with SNG without informing the Commission. Once discovered during the audit process, they seek approval from the Commission while threatening to do imprudent pipe-for-pipe replacement if they are not allowed dollar-for-dollar recovery of non-pipe replacement items.

This matter is a prime example why riders in general can be problematic: The lines of demarcation for recovery can be blurred and the company can be incented to make decisions, not based on financial and engineering prudence, but based on the mechanism of cost recovery. For this reason ,when staff makes its recommendation next month on the Pipe Replacement Rider surcharge for the upcoming year, Staff intends to also recommend that the Commission roll pipe replacement costs back into base rates in the next rate case so that the Pipe Replacement Rider can be terminated. This would prevent rate base items from being recovered as pipe replacement items, and it would prevent decisions from being made based on recovery mechanism rather than financial and engineering prudence. The rolling of the Pipe Replacement Rider back into base rates in the next rate case would not affect the Pipe Replacement Program from a safety perspective, nor would it prevent the company from completing the program within the 10-year time frame as prescribed in the Stipulation.

Q. Are your opinions of the PRP still the same as that presented in previous testimony?

A. Yes, as I stated in my previous testimony[10]:

In my opinion, the thrust of a Pipeline Replacement Proposal is an opportunity for the petitioner to attempt to immediately recover applicable and improper Capital cost and Operation and Maintenance Expenses through a non-traditional rate making annual recovery scheme. We're concerned that the PRP proposal

[10] Michael D. Chrysler Direct Testimony in TRA Docket 04-00034 p.11, lines 8-17.

> will morph from a program to replace applicable Unprotected Steel and Cast Iron mains and services into a recovery scheme to recover any capital projects and O&M expenses it attempts to get away with at inflated costs. We're concerned that the process will require continual review by TRA Gas Pipeline Safety and Energy and Water audit Staff as has been reflected in Georgia and referenced in comments by the GPSC staff.

In the previous example of the East Point Line, GPSC Staff knowledgeable enough to discern appropriate and inappropriate costs and did not simply "sign off" on the Company's project costs - they were responsible for inclusion of costs - the TRA has to ask itself if it wishes its staff to have this responsibility handed to them from the Company. If the present proposal is approved by the TRA, the TRA Audit Staff will have a similar "prudence responsibility" of determination of applicable "replacement costs" as well as the determination of prevention of "double counting" O&M and Capital Costs. Traditional ratemaking has no such shifting of responsibility.

Q. What were the GPSC's concerns and recommendations based on their contact with a similar program in Georgia?

A. Concerns of the GPSC's Staff are significant enough that the Staff has recommended in recorded proceedings that the PRP program be terminated. Danny McGriff at the GPSC (*Gas Pipeline Safety)* previously testified before the TRA[11] :

> However, this rider mechanism has placed a tremendous burden on the Commission's Natural Gas Staff, spending an inordinate amount of time and resources to review over $60 million in capital

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[11] Danny L McGriff, Manager, Facilities Protection Section, Georgia Public Service Commission, Prepared Direct Testimony in TRA Docket 04-00034, p.3 (CAPD Exhibit MDC A-2), lines 66-73

> expenditures and approximately $8 million in operating expenses each year. The Staff has shared concerns with the Facilities Protection Staff (and the Commission) that non-related expenses have been included in the Company's pipe replacement rider calculation. Subsequently, the Natural Gas Staff recommended to the Commission that the pipe replacement rider be abolished and all future program expenses be recovered through base rates.

Said another way, in summarizing comments (CAPD Exhibit MDC A-4) Tony Wackerly, Georgia PSC (*Gas Section*) Utilities Analyst states:

> Second, staff further recommends ending the Pipe Replacement Rider and rolling it into base rates. The reason for this action is to prevent rate base items from being recovered as pipe replacement items and it will prevent decisions from being made based on recovery mechanism rather than financial and engineering prudence. The rolling of the Pipe Replacement Rider into base rates will not affect the Pipe Replacement Program from a safety perspective, nor does it prevent the company from completing the program within the 10-year time frame as prescribed in the Stipulation.

Q. Following Mr. McGriff's review of Mr. Richard Lonn's testimony in 04-00034, did Mr. McGriff have a recommendation for the Tennessee Regulatory Authority regarding Chattanooga Gas Company's proposed bare steel and cast iron pipeline replacement program and related tracker based on almost 6 years (at that time) experience with a similar program in Georgia?

A. Yes, as he stated[12]:

> Given the relatively small amount of replacement proposed by the Company (10 miles per year in Tennessee vs. 230 miles per year in Georgia), a separate revenue tracker is not necessary. This rate of replacement can easily be achieved without a separate rider or

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[12] *Ibid*, p.4

annual rate case, as Atlanta Gas Light Company did from 1989 through 1997. The Commission Staff had reviewed AGLC's replacement program implemented in 1989 to replace 608 miles in 10 years; however, by the end of the 9th program year (November, 1997), 243 miles of cast iron pipe still remained in the Atlanta service center. At this rate, it would take 50 years (Atlanta service center) and 100 years (Peachtree service center) to replace all bare steel and cast iron main in these two service centers alone.

Therefore, an accelerated replacement program was needed in Georgia. However, AGLC was able to effect the replacement of over 300 miles of pipe in 9 years, without a rider or rate case. As I mentioned earlier, a <u>separate revenue tracker will place the burden on the Tennessee Staff to oversee its correct implementation</u>. Finally, contrary to the Company's assertion (that without the separate tracker to recover the cost of the program, Chattanooga Gas Company would be required to file for annual rate relief), the cost and duration of the proposed program is "known and measurable" and could readily be incorporated into rates being determined in the present case. (emphasis added)

Q. With the benefit of hindsight would Mr. McGriff recommend a PRP to the Georgia Public Service Commission?

A. Mr. Hal Novak [TRA Staff]: "So getting back to that given everything you know today, would your answer--if you could step back to 1997 when it first started, so yes or no, would you be prepared to recommend that the Georgia Commission adopt this pipeline replacement rider?"

Mr. McGriff: "I would say, no. I didn't agree with it in the first place."[13]

Q. Is it true that since the last CGC rate case, that Nashville Gas has completed the replacement of approximately 90 miles of bare steel cast iron main?

A. Yes. Since the CGC original proposal in 2004, Nashville Gas completed their approximate 90 miles of bare steel/cast iron mains in 2005 without the request for a PRP recovery rider or filing for rate base recovery. Nashville Gas' commitment

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[13] TRA Docket 04-00034, Hearing Transcript at VII , p. 57 lines 1-7 (CAPD Exhibit MDC A-5).

to system safety and operational responsibility is notable and we commend Nashville Gas and its relationship with the TRA Gas Pipeline Safety Division to provide quality service to its customers. Replacing 90 miles in one year suggests that: 1) from an operational perspective, replacing 90 miles in one year is doable; and 2) replacing 90 miles without rate recovery (much less the need for drawn out PRP tracking mechanism) suggests a moderation in urgency created from a revenue recovery perspective; and 3) traditional rate base recovery remains the fairest, easiest, and best method in recovering costs associated with the replacing bare steel and cast iron main. Once again, the recommendations from the Georgia Public Commission Staff (who deals with the auditing of the plan on a daily basis) respectfully suggest that and a PRP Rider should not be authorized.

Q. What is your recommendation regarding the remaining unprotected bare steel pipe of CGC in Tennessee?

A. We believe that CGC recognizes the necessity of replacing their unprotected bare steel and cast iron main with an accelerated,[14] consistent replacement schedule of approximately 10.2 miles of bare steel/cast iron main per year beginning in F.Y. 2007 with a completion target of 2014. The CAPD does not have an objection with that accelerated schedule and would urge the TRA to sustain that proposal but without adoption of the proposed PRP tracking mechanism.

Q. Does your proposal comply with your proposal in the ATMOS 05-00258 docket?

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[14] CGC is recommending a replacement of approximately 10.2 miles per year of bare steel/cast iron vs. their historical replacement of 6.5 miles of main between 2000 and 2004. (CAPD Exhibit MDC A-7)

A. Yes, my recommendation is that the TRA agree to the CGC proposal made by CGC agreeing to replace the remaining 82 miles of bare steel/cast iron main over 8 years but without the PRP tracker requested. This multi-year proposal is consistent with the 10- year 8.5 miles/per year replacement proposal requested in the ATMOS docket 05-00258.[15]

Q. How would the bare steel replacement schedule work?

A. As referenced previously, the forecasted replacement schedule reflects the proposal detailed by CGC witness Mr. Lonn in Exhibit RRL-1. In keeping with the replacement scheduling proposal discussed in the recent docket (05-00258), CGC should meet, at least annually, with the TRA Pipeline Safety Division in order to prioritize and develop the replacement schedule of construction projects achieving the annual replacement miles agreed (approximately 10.2 miles per year) and memorialized in Lonn Exhibit RRL-1 and MDC A-7.

Q. Do you have an opinion regarding the appropriateness of the recovery of Pipeline Replacement Costs?

A. Yes. As will be discussed by CAPD witness Mr. Buckner, the Consumer Advocate and Protection Division, is using CGC provided replacement costs of $2,000,000 for FY 2006. Further, CGC should have no difficulty adequately absorbing the modest annual depreciation and interest costs associated with main replacement costs while continuing to maintain adequate returns without the need for an additional PRP tracking mechanism. However, CGC would continue to

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[15] CAPD Exhibit MDC A-6 (Revised CAPD Rebuttal MDC-1, Docket 05-00258).

have the option of utilizing traditional ratemaking principles should any additional revenues be necessary.

2. Service Metrics:

Q. Mr. Chrysler, is Chattanooga Gas Company currently monitoring service quality metrics on a monthly basis?

A. Yes. CAPD Exhibit MDC SQT provides a summary of service quality metrics being maintained by Chattanooga Gas Company at this time.

Q. Are these, or any other service quality metrics, being regularly reported to the Tennessee Regulatory Authority or the Consumer Advocate and Protection Division?

A. No. The response to Minimum Filing Guidelines #28 simply indicates that the service metrics identified in CAPD Exhibit MDC SQT are only "maintained" by CGC; i.e., they are not "reported" to regulators or advocates.

Q. Why are the CGC service metrics so significant at this time?

A. According to Minimum Filing Guidelines #14, CGC indicates that several management initiatives are being pursued at this time including the recent outsourcing of its meter reading function. Service metrics are needed to monitor the results of such initiatives that could hamper the quality of service provided to consumers. For example, ATMOS customers, regulators, and advocates clearly understand the potential problems caused by outsourced meter readers not doing their job and the lack of management oversight as alleged in TRA Docket 05-00150.

Q. Could you summarize the CAPD proposal for Service Metrics and Reporting?

A. Yes. Consumers need the assurance of the Company's commitment to operational service quality and reporting on a going forward basis. The Service Metrics being maintained by CGC in Exhibit SQT, as well as the metrics reported by AGL and affiliate NUI in New Jersey, indicate an understanding of the importance of measuring operational service quality by the utility as well as other regulators. In keeping with this understanding, we believe the TRA should adopt the proposed service metrics identified in CAPD Exhibit SQ and request the Company reporting operations on a monthly basis. The Company should be required to report the service metrics to the TRA and provide copies to the the CAPD.

Q. Are the service metrics proposed in addition to other service metrics that may/should be reported in Tennessee?

A. Yes. The service metrics proposed are the same service metrics that have been reported to the CAPD since 2003 by Nashville Gas Company and reflect a "generic summary" of metrics covering a cross section of company operations. AGL Resources has suggested that call Center Service Metrics covering WIPRO Operations[16] have been developed and will be reported in Tennessee as part of their moving operations off-shore. These proposed metrics also include certain benchmarks that WIPRO Operations will have to achieve within a short time frame

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[16] WIPRO service metrics and benchmarks provided to CAPD in response to CAPD Data Request #1, Q. 78 (Marked Confidential and Filed Under Protective Seal)

to achieve contractual obligations. Additionally, AGL Resources[17] (CAPD Exhibit MDC - GA1) and New Jersey affiliate (NUI)[18] (CAPD Exhibit MDC - M2) currently report operations covering prescribed operational metrics in Georgia and New Jersey. The CAPD believes that Tennessee consumers should have, at the very least, CGC report operations measured against the "generic metrics" as identified in Exhibit SQ, but as additional metrics are developed or required due to new operations, contracts, or to meet other state regulatory requirements; and as requirement benchmarks are developed, we would request that the Company update the metrics and benchmarks for reporting in Tennessee.

Q. Has the Authority discussed the need for Service Metrics and Reporting recently?

A. Yes. The following comments were made in an exchange between Director Roberson and Ms. Beth Reese of AGL Resources in a transcript of the proceeding: *Presentation by Chattanooga Gas Concerning the Shifting of Certain Routine Functions to WIPRO*[19], Monday, June 26, 2006, p. 22, 23:

> Director Roberson: "On the service measurements, the quality measurements, it appears that the company has a matrix of measurements that you're going to be looking at on it."

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[17] Georgia Public Service Commission, Chapter 515-7-7-.04 Service Quality Standards: Customer Service, Billing and Metering , per CAPD Data Request #1, Q. 77.

[18] Letter to New Jersey PSC dated March 31, 2006 detailing Elizabethtown's (NUI) performance in a number of critical areas including: safety and reliability, customer satisfaction, customer service, operational efficiency, employee safety, and customer complaints. Per CGC response to CAPD Data Request #1, Q.77

[19] CAPD Exhibit MDC A-8

Ms. Reese: "Yes."

Director Roberson: "And those are going to be on a monthly basis? The company will get those on a monthly basis?"

Ms. Reese: "We will get those on a monthly basis, and we'll monitor them daily. Average speed of answer, we can monitor daily. Quality, we can monitor, so if we see a trend going a negative way, we can react to that fairly quickly."

Director Roberson: "So are these service standards that you would voluntarily share with the Authority on a monthly basis so that we could, as well, monitor the service? So the company would agree to provide those to our Consumer Services Division?"

Ms. Reese: "Yes."

Director Roberson: "Okay. That's all for now."

Q. Does that complete your testimony?

A. Yes, it does.

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Before the

<u>TENNESSEE REGULATORY AUTHORITY</u>

IN RE:

PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND CHARGES, COMPREHENSIVE RATE DESIGN PROPOSAL, AND REVISED TARIFF

DOCKET NO. 06-00175

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EXHIBITS
OF
MICHAEL D. CHRYSLER

****

October 16, 2006

Michael D. Chrysler Exhibits
In TRA Docket 06-00175

Chattqanooga Gas Company

Exhibit Reference	Description
	Pipeline Replacement Exhibits:
A -1	TRA Order 04 - 00034
A - 2	Danny McGriff Testimony in 04-00034
A - 3	Executive Summary, Report to GPSC in Docket 8516-U, 7/29/03 by Tony Wackerly
A - 4	Executive summary, 8516-U,, Staff's Audit Report
A - 5	Hearing transcript, testimony of Danny McGriff in TRA Docket 04-00034, p. 57, Cross-Examination by Hal Novak for TRA
A - 6	ATMOS Bare Steel Replacement Analysis
A - 7	CGC Bare Steel Replacement Analysis
A - 8	WIPRO Presentation by AGL To TRA, June, 2006
	Service Quality Metrics and Reporting Exhibits:
SQ	CGC Proposed Service Metrics
GA	Georgia PSC Service Standards For the Electing Distribution Company
GA1	Georgia Service Qualtiy Standards - Reports By Function - As reported in Georgia
M - 2	Elizabethtown (NUI) service Metrics - as reported in New Jersey
SQT	CGC Service Quality Summary of Performance Metrics maintained the past two years. Data Source: CGC Minimum Filing Guidelines #28 in TRA Docket 06-00175, 7/14/06

CAPD EXHIBIT
MDC A-1

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

October 20, 2004

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

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,

[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)

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

[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.

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[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

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[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

[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.

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[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

[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,

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[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

[90] *See* http //federalreserve gov/boarddocs/press/monetary/2004/200408 10/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

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

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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]

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[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

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[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)

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%.

[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). REVENUE CONVERSION FACTOR

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). REVENUE DEFICIENCY OR SURPLUS

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). RATE DESIGN

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

[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

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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, Chairman

Deborah Taylor Tate, Director

Sara Kyle, Director

State of Tennessee
Before The Tennessee Regulatory Authority

Prepared Direct Testimony
Of
Danny L. McGriff

In Re:
Chattanooga Gas Company
Docket 04-00034

Q. **Please state your name, business affiliation and address and job title.**

A. Danny L. McGriff, Manager, Facilities Protection Section, Georgia Public Service Commission, 244 Washington Street, Atlanta, Georgia 30334.

Q. **Please give a brief outline of your background and professional experience.**

A. I began my employment with the Georgia Public Service Commission as a Senior Pipeline Safety Inspector in June 1980, advanced to the position of supervisor in July of 1996 and was promoted to Manager in August 2001. I am responsible for the supervision and coordination of programs designed to ensure the safety of natural gas transmission and distribution and liquefied natural gas (LNG) utility operations. In addition to managing Commission Staff members involved in the performance of statewide natural gas safety inspections, I am responsible for interpreting state and federal laws, rules, codes, standards, regulations, policies and procedures concerning various natural gas safety programs. Finally, I serve as the agency expert regarding the safety of natural gas pipeline system design, construction, installation, inspection, operation, maintenance, emergency procedures, repairs and cathodic protection.

Q. **What is the purpose of your testimony?**

A. I was requested by the Office of the Attorney General of the State of Tennessee to address the following issues:

1. Federal requirements regarding the replacement of cast iron/bare steel pipe;

2. The condition of Atlanta Gas Light Company's (AGLC) system in 1998 that brought about a Rule Nisi and eventually led to a stipulation setting forth the parameters of the current pipe replacement program in Georgia; and
3. Concerns shared by the Georgia Public Service Commission's Natural Gas Staff relating to the utilization of a separate rider or surcharge to customers to pay for the pipe replacement program.

Q. Please describe the Federal requirements you mentioned.

A. In 1991, the U. S. Department of Transportation issued a Pipeline Safety Alert Notice (ALN-92-02) recommending that all natural gas distribution companies develop a program to identify and replace cast iron pipe. In addition, under 49 CFR (Code of Federal Regulations), operating companies with pipelines that are determined to be bare and/or ineffectively coated were to have procedures to address pipelines where active corrosion was found.

Q. Please describe the circumstances leading to the issuance of a Rule Nisi against Atlanta Gas Light Company, subsequently culminating in a mandatory pipe replacement program.

A. Issued January 6, 1998, the Rule Nisi, based on Pipeline Safety and follow-up inspections from May 1996 through October 1997, indicated a history of active corrosion since 1980. Review of Company records revealed, for the Atlanta service center alone, 5,661 leaks (3,169 of those identified as Grade I) in 1994; 4,438 (2,558 Grade I) in 1995; and 4,007 (2,585 Grade I) in 1996. Additionally, the Atlanta service center records from 1994 through 1997 showed leaks on cast iron pipe that indicated the existence of graphitization.

Q. Were there any other conditions that warranted the Rule Nisi?

A. Yes. Atlanta Gas Light Company was cited for the following deficiencies:

1. Failure to locate underground facilities;
2. Improper grading of leaks;
3. Untimely repair of Grade I leaks;
4. Safety equipment not made available to all repair crews;

5. Failure to maintain a leak database;
6. Inadequate training to properly perform and record pit depth gauge readings;
7. Inadequate distribution of the Company's Operations Procedure Manual;
8. Inadequate inspection of meters read by electronic reading telemetry devices;
9. Improper locking and sealing of disconnected meters;
10. Inadequate leak surveys and related records;
11. Inadequate marking of above ground regulators; and
12. Improper incident notification.

Q. **Were all of the aforementioned deficiencies addressed in the stipulation as well?**

A. Yes. In addition to the mandatory replacement of over 2,300 miles of bare steel and cast iron pipe in AGLC's system within 10 years, the stipulation of June 10, 1998 contained a non-performance penalty provision of $100,000 per violation.

Q. **Is this program in Georgia funded by customers by way of a separate rider or surcharge, similar to the one being proposed in this case?**

A. Yes. Given the magnitude of the project in Georgia, it was believed (at first) that this methodology would reduce rate shock as the program was phased in, and implementation could begin immediately, rather than wait 6 months or more for the conclusion of a rate case. However, this rider mechanism has placed a tremendous burden on the Commission's Natural Gas Staff, spending an inordinate amount of time and resources to review over $60 million in capital expenditures and approximately $8 million in operating expenses each year. The Staff has shared concerns with the Facilities Protection Staff (and the Commission) that non-related expenses have been included in the Company's pipe replacement rider calculation. Subsequently, the Natural Gas Staff recommended to the Commission that the pipe replacement rider be abolished and all future program expenses be recovered through base rates.

Q. **Have you reviewed the testimony of Richard Lonn in this case, Docket 04-00034?**

A. Yes.

Q. **Do you have any recommendation for the Tennessee Regulatory Authority regarding Chattanooga Gas Company's proposed bare steel and cast iron pipeline**

replacement program and related tracker, given almost 6 years experience with a similar program in Georgia?

A. Yes. Given the relatively small amount of replacement proposed by the Company (10 miles per year in Tennessee vs. 230 miles per year in Georgia), a separate revenue tracker is not necessary. This rate of replacement can easily be achieved without a separate rider or annual rate case, as Atlanta Gas Light Company did from 1989 through 1997. The Commission Staff had reviewed AGLC's replacement program implemented in 1989 to replace 608 miles in 10 years; however, by the end of the 9th program year (November 1997), 243 miles of cast iron pipe still remained in the Atlanta service center. At this rate, it would take 50 years (Atlanta service center) and 100 years (Peachtree service center) to replace all bare steel and cast iron main in these two service centers alone. Therefore, an accelerated replacement program was needed in Georgia. However, AGLC was able to effect the replacement of over 300 miles of pipe in 9 years, without a rider or rate case. As I mentioned earlier, a separate revenue tracker will place the burden on the Tennessee Staff to oversee its correct implementation. Finally, contrary to the Company's assertion (that without the separate tracker to recover the cost of the program, Chattanooga Gas Company would be required to file for annual rate relief), the cost and duration of the proposed program is "known and measurable" and could readily be incorporated into rates being determined in the present case.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
TENNESEE REGULATORY AUTHORITY

In Re: Application Chattanooga Gas Company,
A Division of Piedmont Natural Gas Company, Inc.,
For an Adjustment of its Rates and Charges, the Approval of Revised Tariffs
And the Approval of revised Service Regulations
Docket No. 04-00034

AFFIDAVIT OF DANNY L. MCGRIFF

Danny L. McGriff, being first duly sworn, deposes and says that he is the Danny L. McGriff referred to in the document entitled "Pre-Filed Direct Testimony of Danny L. McGriff on Behalf of the Georgia Public Service Commission"; that the exhibit accompanying that document was prepared by him or under his supervision; that he has read such testimony and is familiar with its contents; and that the contents of that document are true, correct, accurate and complete to the best of his knowledge, information and belief in this proceeding.

Danny L. McGriff

Subscribed and sworn to me before
this 20th day of July 2004.

My commission expires:

Notary Public

HELEN O'LEARY
MY COMMISSION EXPIRES
MARCH 3 2007
DEKALB COUNTY, GA.
NOTARY PUBLIC

CAPD EXHIBIT
MDC A-3

July 29, 2003

To: All Commissioners
Deborah Flannagan
Tom Bond
Nancy Tyer

From: Tony Wackerly, Utilities Analyst

Subject: DOCKET NO. 8516-U: **Atlanta Gas Light Company Pipe Replacement Program.** Consideration of Staff's Recommendation on Atlanta Gas Light Company's Request for a Declaratory Ruling.

During its Second Quarter Audit of the Atlanta Gas Light Company (AGLC) Pipeline Replacement Rider, Gas Staff discovered that right-of-way charges that the Company had booked as expenses to the Rider are actually rate base items. These expenses were related to the possible replacement of the East Point Line. In addition, Staff discovered that the Company also intended to book certain anticipated expenses to the Rider though these anticipated charges should be treated as rate base items. The charges in question were not for costs of replacing pipes. Instead, they were related to a pressure improvement agreement between Atlanta Gas Light Company and Southern Natural Gas and capital expenditures for new right-of-ways that will not be used for the pipe replacement program. The Company's funding for these types of items comes through base rates, and the Company was prepared to enter into an agreement with Southern Natural Gas for a pressure improvement program without informing the Commission of its intensions.

After the audit, Staff met with the Company numerous times, and using discovery, to gather information on the proposed agreement between Atlanta Gas Light Company and Southern Natural Gas for pressure improvement. Staff learned that AGLC began the right-of-way project as early as April 2001 with these associated costs going to the rider each year, but abandoned this effort when Southern Natural Gas agreed to work with the Company on a pressure improvement program. At Staff's request, the Company produced three options for the replacement of the East Point Line:

Option-A: Replace the East Point Line in its present location at $26 million.
Option-B: Build a new pipeline from Riverdale to Sewell Road at $20 million.
Option-C: Enter into a pressure improvement agreement with Southern Natural Gas to move or rebuild an existing tapping station from Sewell Road to Ben Hill at a cost of $4.0 million, SNG charges to AGLC will be $2.5 million, and pipe insertion in the old East Point Line at $2.9 million. With the right-of-way expense of $3.3 million already incurred from abandoning Option-B, this will bring the total to $12.7 million in total costs that the Company wants to charge to the Pipe Replacement Rider.

Staff agreed with the Company that Option-C is the only prudent option, but Staff does not agree that the $3.3 million in right-of-way costs, the $4.0 million to replace the tapping station, or the $2.5 million in SNG charges should be recovered through the Pipe Replacement Rider. These costs should be recovered through base rates because they are not related to pipe replacement. The $2.9 million associated with Option-C is deemed a legitimate expense under the pipeline replacement program.

The Company has continually asserted that if they are not allowed to recover these items through the Rider, then they will simply do pipe-for-pipe replacement without seeking a more prudent method of reducing costs. Staff believes the company has reached a conflict of interest between cost recovery and financial and engineering prudence. There can be a demarcation between cost recoveries, such as rate base and the Pipe Replacement Rider. When a pipe replacement project is being considered, it may have elements of both types of recovery, and it is prudent to recognize this demarcation and make the appropriate decision on allocating which costs should be recovered under each mechanism. The Company has failed to understand this line of demarcation between recovery mechanisms by attempting to go forward with this pressure improvement project with SNG without informing the Commission. Once discovered during the audit process, they seek approval from the Commission, while threatening to do imprudent pipe-for-pipe replacement if they are not allowed dollar-for-dollar recovery of non-pipe replacement items.

This matter is a prime example why riders in general can be problematic: The lines of demarcation for recovery can be blurred and the company can be incented to make decisions, not based on financial and engineering prudence, but based on the mechanism of cost recovery. For this reason, when Staff makes its recommendation next month on the Pipe Replacement Rider surcharge for the upcoming year, Staff intends to also recommend that the Commission roll pipe replacement costs back it into base rates in next rate case so that the Pipe Replacement Rider can be terminated. This would prevent rate base items from being recovered as pipe replacement items, and it would prevent decisions from being made based on recovery mechanism rather than financial and engineering prudence. The rolling of the Pipe Replacement Rider back into base rates in the next rate case would not affect the Pipe Replacement Program from a safety perspective, nor would it prevent the Company from completing the program within the 10-year time frame as prescribed in the Stipulation.

Staff **recommends** the following: First, Staff recommends that Atlanta Gas Light Company be ordered to pursue Option-C as the most prudent option. Second, Staff recommends disallowing the $3.3 million in right-of-way costs associated with Option-B because it is not part of the pipe replacement program, and, to the extent that it has already been recovered through the Rider, this amount should be credited back to the Pipe Replacement Rider for the coming recovery year. Third, Staff recommends denying recovery through the Pipe Replacement Rider of the $4.0 million to move the tapping station from Ben Hill to Sewell Road and the $2.5 million in SNG associated expenses. Fourth, Staff recommends the recovery of the $2.9 million for pipe insertion at the East Point Line be recovered through the Pipe Replacement Rider.

EAST POINT LINE /
FORREST PARK

26,0
12.7 Opt C
13.3

Exhibit-WL-4

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION
STATE OF GEORGIA

DOCKET NO. 8516-U

IN RE: ATLANTA GAS LIGHT COMPANY PIPE REPLACEMENT PROGRAM

ORDER ON ATLANTA GAS LIGHT COMPANY'S PETITION FOR A DECLARATORY RULING

FINDINGS OF FACT AND CONCLUSIONS OF LAW

On January 6, 1998, the Georgia Public Service Commission ("Commission") issued a Rule Nisi against Atlanta Gas Light Company ("AGLC" or "Company"). In that Rule Nisi, it was alleged that various violations had occurred in the operation of the Company's pipeline system. On June 11, 1998, the Adversary Staff of the Commission and the Company filed a proposed stipulation in this matter and a hearing on the merits of the stipulation was held before the Commission on July 8, 1998. The terms of this stipulation include a provision authorizing AGLC to recover over a ten year period through a pipe replacement rider (rider) those costs incurred to replace the portions of its pipeline system that were corroded and/or leaking. Additionally, the stipulation provided that Staff audit the expenses incurred by the Company in complying with the terms of the stipulation. On September 3, 1998, an order was entered by the Commission accepting the stipulation.

During its 2003 Second Quarter Audit of AGLC's Pipeline Replacement program, Gas Staff found several cost items inappropriately charged to the pipe replacement rider. Many of these expenses were related to the potential replacement of the East Point Line. In addition, Staff discovered that the Company also intended to book certain anticipated base rate items through the pipe replacement rider. These items were the result of a pressure improvement agreement between AGLC and Southern Natural Gas (SNG) and capital expenditures for new rights-of-way. Staff further discovered that the new rights-of-way were not be used for the pipe replacement program.

As a result of Staff's investigation, Staff met with the Company and requested more information regarding these costs. In response, the Company recommended three options to consider for replacing the East Point Line:

Option-A: Replace the East Point Line in its present location at $26 million.
Option-B: Build a new pipeline from Riverdale to Sewell Road at $20 million.

Option-C: Enter into a pressure improvement agreement with Southern Natural Gas with total costs of $12.7 million.

The Option-C costs in question were:

1. $3.3 million in right-of-way expenses that were abandoned.
2. $4.0 million to move a tapping station from Ben Hill to Sewell Road as part of the pressure improvement agreement between the Company and SNG.
3. $2.5 million in SNG charges related to the pressure improvement agreement.
4. $2.9 million to insert replacement pipe in the East Point Line.

After a thorough review of the Company's proposed options, Staff agreed with the Company that Option-C was the most prudent option from a financial and engineering perspective. However, Staff and the Company were in disagreement on the recovery mechanism for the cost of Option C.

On June 30, 2003, AGLC filed a petition for a declaratory ruling requesting the Commission resolve the dispute over which items of costs in Option C could be recovered through the Rider. In their petition, the Company sought a ruling to recover all $12.7 million of costs related to Option C through the Pipe Replacement Rider. The Company argued that the cost incurred was a result of the stipulation and recovery was provided for by the terms of the stipulation. Additionally, the Company argued that the Commission Staff had a narrow interpretation of pipe replacement and that such an interpretation would penalize the Company for looking at innovative ways to replace pipes in congested areas. The Company recommended the creation of a process by which the Company would give Staff advance notice of cost saving projects like the one proposed in Option C.

Staff argued that there should be a clear demarcation between cost recovery mechanisms. Specifically, cost recovery for a project like Option C should be allocated between base rate and pipe replacement in conformity with the category that best fits each cost. (1) Additionally, Staff challenged that the $3.3 million for right-of-way costs be disallowed from the Pipe Replacement Rider and recovered through base rates because that cost was not to be used for pipe replacement. (2) Staff contended that the $4.0 million for the tapping station should be disallowed from the Pipe Replacement Rider and recovered through base rates because it was part of the pressure improvement agreement with SNG. Though the Company claimed it was also budgeted during the test period, the tapping station has yet to be built, and the test period ended in May 2003. (3) Staff contended the $2.5 million in SNG associated costs were not budgeted for at all, and certainly had nothing to do with pipe replacement, and therefore these costs should be disallowed and recovered through base rates. The Company stated these costs were prudent for pipe replacement. (4) Staff and the Company agreed that the $2.9 million should be recovered through the Pipe Replacement Rider because it is indeed pipe replacement.

The Commission Finds and Concludes the following:

✓ allowed

p. 4

Can $3.3
2.9
6.2

$4.0
2.5
6.5

Total 12.7

1. The Company is ordered to pursue Option-C as the most prudent option from a financial and engineering perspective.

2. The Company can recover the $3.3 million in right-of-way costs through the Pipe Replacement Rider. In allowing recovery of this expense through the rider the Commission finds compelling the fact that the Company included these costs in the budget for the last rate case as pipe replacement, and the budgeted amounts where largely utilized during the test period filed in the last rate case.

3. The Company cannot recover $4.0 million to move the tapping station from Ben Hill to Sewell Road through the Pipe Replacement Rider, but it can be recovered through base rates. This cost is directly related to a pressure improvement and is better identified as a base rate item.

4. The Company cannot recover the $2.5 million in SNG associated costs for the pressure improvement agreement through the Pipe Replacement Rider, but it can be recovered through base rates. The Commission does not find that this cost is properly identifiable as pipe replacement costs, but instead a pressure improvement.

5. The Company can recover the $2.9 million for pipe insertion at the East Point Line through the Pipe Replacement Rider.

6. The Company shall continue to seek the most cost efficient means to improve its system through pipe replacement as provided by the Stipulation and to avoid imprudent and excessive costs to the rider.

7. From the date of this Order the Company shall develop a process whereby Company shall identify prudent cost efficient opportunities for pipe replacement and provide those options to Staff for the Staff to review prior to its proposed implementation date. In identifying these opportunities the Company shall identify those costs that will be allocated to rate base and those that will be allocated to the pipe replacement rider.

ORDERING PARAGRAPHS

The Commission decides, based upon its evaluation and determinations as set forth in the preceding Findings of Fact and Conclusions of Law that is appropriate to Order the following:

WHEREFORE IT IS ORDERED, that the Company will pursue Option-C as the most prudent option for pipe replacement. The Company can recover the $3.3 million in right of way expenses and the $2.9 million of pipe replacement cost through the Pipe Replacement Rider.

ORDERED FURTHER, the Company cannot recover the $4.0 million associated with moving a tapping station from Ben Hill to Sewell Road nor the $2.5 million in Southern Natural Gas charges related to the pressure improvement agreement through the Pipe Replacement Rider, but must be recovered only through base rates.

ORDERED FURTHER, the Company shall continue to seek the most cost efficient means to improve its system through pipe replacement as provided by the Stipulation and to avoid imprudent and excessive costs to the rider. From the date of this Order the Company shall develop a process whereby the Company shall identify prudent cost efficient opportunities for pipe replacement and provide those options to Staff for the Staff to review prior to its proposed implementation date. In identifying these opportunities the Company shall identify those costs that will be allocated to rate base and those that will be allocated to the pipe replacement rider.

ORDERED FURTHER, any motion for reconsideration, rehearing, or oral argument shall not stay the effectiveness of this order unless expressly ordered by the Commission.

ORDERED FURTHER, that jurisdiction over this proceeding is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem proper.

The above by action of the Commission in Administrative Session on the 19th day of August 2003.

Reece McAlister Executive Secretary	Robert B. Baker, Jr. Chairman
Date	Date

Executive Summary

DOCKET NO. 8516-U: Atlanta Gas Light Company Pipe Replacement Program: Staff's Audit Report: Consideration of Staff's Recommendation on the Pipe Replacement Surcharge for Cost Year-5.

Staff recommends the following: First, Staff recommends the Cost Year-5 surcharge to be set at $1.11 per customer. This is a result of Staff and the Company reaching a mutual agreement that the average Corrosion Leak Repair will be set as a fixed cost of $1,064 per corrosion leak for the duration of the Pipe Replacement Program. Second, Staff further recommends ending the Pipe Replacement Rider and rolling it into base rates. The reason for this action is to prevent rate base items from being recovered as pipe replacement items, and it will prevent decisions from being made based on recovery mechanism rather than financial and engineering prudence. The rolling of the Pipe Replacement Rider into base rates will not affect the Pipe Replacement Program from a safety perspective, nor does it prevent the Company from completing the program within the 10-year time frame as prescribed in the Stipulation.

CAPD EXHIBIT
MDC A-5

BEFORE THE TENNESSEE REGULATORY AUTHORITY

ORIGINAL

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

T.R.A. DOCKET ROOM

TRANSCRIPT OF PROCEEDINGS

Wednesday, August 25, 2004

VOLUME VII

APPEARANCES:

For Chattanooga Gas:	Mr. L. Craig Dowdy Ms. D. Billye Sanders
For Chattanooga Manufacturers Association:	Mr. Henry Walker Mr. Ray Childers
For Consumer Advocate:	Mr. Timothy Phillips Mr. Vance L. Broemel
For TRA Staff:	Mr. Aster Adams Mr. Hal Novak

Reported By:
Cheryl Buckelew Smith, RPR, CCR

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Q. So getting back to that given everything you know today, would your answer -- if you could step back to 1997 when it first started, so yes or no, would you be prepared to recommend that the Georgia Commission adopt this pipeline replacement rider?

A. I would say no. I didn't agree with it in the first place.

MR. NOVAK: Okay. No further questions from Staff.

CHAIRMAN MILLER: Thank you.

DIRECTOR TATE: I'm sorry. I just want to follow up and ask you one other thing, Mr. McGriff. Welcome to Tennessee.

THE WITNESS: Thank you.

DIRECTOR TATE: Are you saying that you and your staff have had an opportunity to follow up more closely with the company since this rider went into effect?

THE WITNESS: Yes, ma'am. And one of the things I can say with the staff and working with the company, we have always worked, you know, side by side with the company whether we agree or disagree. But, you know, when we disagree, you know, they make corrections and then we agree on things and everything works out with the rider situation.

Pipeline Replacment Schedule
ATMOS Energy
05-00258

CAPD EXHIBIT
MDC A-6

ATMOS Main Replacement Statistics*

		Pipe Replaced Feet	Miles	Cost Per Ft.	Annual Replacement Cost	Cost Inflation	ATMOS R.O.E. In TN**
	1997	44,658	8.458	$ 25.08	$ 1,119,984		11.8%
	1998	26,616	5.041	25.59	681,129	2.03%	18.3%
	1999	8,739	1.655	26.11	228,203	2.03%	8.2%
	2000	7,738	1.466	26.65	206,188	2.07%	9.7%
	2001	6,403	1.213	27.19	174,097	2.03%	20.7%
	2002	14,500	2.746	27.74	402,300	2.02%	20.3%
	2003	19,839	3.757	28.31	561,663	2.05%	18.3%
	2004	22,883	4.334	28.89	661,063	2.05%	14.2%
	2005	51,484	9.751	29.48	1,517,666	2.04%	
	2006	44,707	8.467	30.08	1,344,787	2.04%	
	2007	60,000	11.364	30.68	1,840,896	1.99%	
1997-2004		151,376	28.7	$ 26.65	$ 4,034,627	2.04%	
average		18,922	3.6	26.95	504,328		
11 yr.avg.		27,961	5.3	27.80	794,361		
Total 11-Year		307,567	58.251	28.41	$ 8,737,976		

<u>Forecasted Replacement @ 45,000 Feet Per Year</u>

	2007	45,000	8.523
	2008	45,000	8.523
	2009	45,000	8.523
	2010	45,000	8.523
	2011	45,000	8.523
	2012	45,000	8.523
	2013	45,000	8.523
	2014	45,000	8.523
	2015	45,000	8.523
	2016	45,000	8.523
Total 10-Year		450,000	85.227

*Data Source ATMOS Response to CAPD data request II, Parta IV, Question 1
** Dr. Brown's Schedule 7 from initial petition filing in the docket (attached)

Chattanooga Gas Company
Detail of Bare Steel/Cast Iron Replacement

Docket # 06-00175

Miles of Main To Be Replaced

Year	Unprotected Steel	Cast Iron	Total	Miles Replaced	
		Actual Data:			
1990	150	121	271		
2000	94	22	116	155	
2003	57	38	95	21	
2004	56	34	90	5	116 - 90 = 26/4 = 6.5 miles/yr.
2005	54	32	86	4	
		Forecast Data:			
2006		*	82	4	* = Richard Lonn's testimony p. 2
2007			71.24	10.76	Richard Lonn's Exhibit RRL-1
2008			61.04	10.2	..
2009			50.84	10.2	..
2010			40.64	10.2	..
2011			30.44	10.2	..
2012			20.24	10.2	..
2013			10.04	10.2	..
2014			-0.16	10.2	..

Note:
1990, 2003 data source = Exhibit MDC AR 7100 (as filed in 04-00034)
2000, 2004, 2005 Company DOT 7100 Reports - response to CAPD Data Request #1, Q. 67

BEFORE THE TENNESSEE REGULATORY AUTHORITY

IN RE:)
)
PRESENTATION BY CHATTANOOGA GAS)
CONCERNING THE SHIFTING OF)
CERTAIN ROUTINE FUNCTIONS TO)
WIPRO)

TRANSCRIPT OF PROCEEDINGS
Monday, June 26, 2006

APPEARANCES:

For AGL Resources: Ms. Beth Reese
Mr. Archie Hickerson

Reported By:
Carol A. Nichols, RDR, CRR, CCR

(The aforementioned proceedings came on to be heard on Monday, June 26, 2006, beginning at approximately 2:10 p.m., before Chairman Ron Jones, Director Sara Kyle, Director Pat Miller, and Director Eddie Roberson, when the following proceedings were had, to-wit:)

MS. REESE: Good afternoon, Mr. Chairman, Directors. Thank you very much for inviting us in today. My name is Beth Reese, and I'm the Vice President of Customer Service for AGL Resources, of which Chattanooga Gas Company is a subsidiary. And I'm here today to speak a little bit about our business process outsourcing that Archie talked to you about a month ago when he announced what we were doing.

First, I thought it would be helpful for us to talk about a background. Part of our process always is to look at what we do well, what others do well in the space that we operate in, and how we can partner with others that can help provide services for us. And along those lines, about a year ago, we commissioned an analysis to review certain processes and identify ones that may be matched for outsourcing.

As a result of that, we determined that we had some processes that could be outsourced. We

issued an RFP in December of last year requesting bids from six different vendors, some from North America, some from South America and India. And the vendors that we sent the RFP to were selected based on their current Gartner ratings at the time. As a result of the responses that we got back, we set up site visits to South America and to India.

The two U.S.-based vendors did not respond to our RFP, so we did not go visit their sites. Based on the site visits and the oral presentations that the vendors provided to us, we selected Wipro. Wipro is a services provider based in Bangor, India, and we selected them based upon their overall service delivery capabilities. They have a very strong overall quality program. They're process focused. They institute Six Sigma, Lean Sigma, Kaizen, and a lot of different process-focused quality programs.

They're experts in the call center industry and specifically with world class clients such as Delta, Dell, and United. They have very solid training programs, and we were fortunate to be able to sit in one of those classes when we visited their site in India. And they have very good employees who have a strong education base. Everyone has a high school education. Most people are in the process of either

completing their college degree or have completed their college degree. And they have a lot of available employees who are excited about working in specifically call center space.

So why did we embark on business process outsourcing? We will see an immediate service level improvement and increasing service level attainment, and I'll talk specifically about that in a later slide. We will be partnering with the vendor to apply quality programs to all of our outsourced business processes. And by partnering with a vendor who is an expert in these processes, they can bring best practices to us so that we can continue to enhance the services we provide to our customers.

That also allows us to focus on the high value strategic work. And what we really mean by that is being able to focus on our customers and the issues that they're having to deal with and the reasons that they're actually having to call us to begin with: In-scope services, customer service phone inquiries, billing inquiries, payments and those related inquiries, establishing or reestablishing gas service, discontinuing gas service, and what we call back office or backline support.

We have three major information systems

that support customer service. We have a meter reading system, a customer information service, and an automated dispatch system. Sometimes those systems don't talk as effectively as we'd like them to, and it requires some intervention. And those would need to be the exceptions, field order exceptions worked as part of backline support.

Collection support, really about bankruptcy claims processing, collection agency payments and claims processing -- and I have another slide that goes into a little bit more detail on that. And then on limited basis of engineering construction, back office support, again, the places where our systems aren't as automated as we'd like them to be, and they require some manual intervention, very routine tasks that can be easily mapped, easily documented, and easily sent to a third party to perform, and then updating our systems mapping.

Our collection processes. Specifically, the regulatory collection process remains the same. That's really built into our system as to when an account is sent through the process. For outsourcing, it's specifically backline functionality. Again, kind of those processes that aren't automated that require manual interventions: Bankruptcy

processing, returned check processing to the degree that it can be automated, pending work queues are those things that within our system require attention, agency statements and any chargeoff exception reports.

Today, our process for customer contact is that a customer, if they have an issue with their bill generally or service, they're moving into a new home or moving out of a new home or an old home, they contact one of our CSRs by calling a 1-800 number, and the CSR resolves the issue. If the CSR at the time is unable to resolve the issue, if it requires a higher level of authority or if they have a question about the account, they'll raise that to a team leader, if necessary, and if that team leader is unable to resolve the issue, it gets forwarded to the management.

The only piece of that puzzle that really is changing is that rather than calling and talking to somebody who directly works for AGL Resources as an employee, our customers will now be contacting a vendor CSR. So they're calling the same 1-800 number, and a vendor CSR will resolve the issue. If the vendor CSR is unable to resolve the issue, it will get escalated in the same manner. The one thing that we have done is we have established or will be establishing when we send our calls to our vendor is an escalation

help desk which will be available during the entire process to help answer any questions that the vendor CSR cannot handle.

Right now, our estimate is that we'll have 40 people that staff that desk. We only have about 140 CSRs today for all of AGL Resources, and we'll have a very large number of people that we're retaining, and we will maintain that desk as long as we feel it's necessary. Most importantly, from a safety perspective, our emergency or leak response calls will remain in Georgia where they come in today. That process will not change.

If by accident the only phone number that a customer calls in -- has access to calls into and actually reporting a leak and it's customer service and they end up at our vendor, the process will remain as it is today. Today, we have a separate emergency response team that takes all the leak calls for all of our companies.

If a leak call comes in to our regular customer service, we'll do what's called a warm transfer, which is I'm a CSR, I have a customer on the line who is reporting a leak, and I call Director Roberson, and I say, I have a customer here who has a leak. He acknowledges that he has the call, and we'll

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do a warm transfer. It's a process we have today. It's a process that we'll have in the future as well.

The transition plan and timeline. The team from our vendor Wipro arrived today actually in Atlanta. They'll be here documenting our current processes. During this month and next month, we'll be procuring and implementing our supporting technology, which is a couple of things. It's both IT as well as a new system that we have going live I'll talk about a little bit later.

Mid August, we begin the training in the call center. We have a team who will be spending about seven weeks in India in the August/September time frame. We will be conducting the training, ourselves. So from August 16th until September 5th, we'll be actually doing classroom training. And then beginning September 6th through September 19th, we'll being doing parallel run of calls, which means that for a four-hour period of time during those two weeks, customers will call in and their calls will be routed, based on a 50/50 split, to our current call center and our vendor.

And we'll be spending four hours of those days each day debriefing on what they learned and what issues they saw, what they hadn't learned in the classroom and the questions they had. And then we'll

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plan on coming over on September 20th, and we'll keep a staff of people -- at least one person -- over in India providing support as we go live.

Customer response. Our plan is that all processes will remain the same and that our transition is expected to have minimal disruption, so we're really planning that we'll do this right and have our processes in place so that our customers don't feel any effect on this at all. And in order to really make sure that that happens, we will perform all the initial training, as I mentioned, including voice neutralization and cultural training, which we will be as well as Wipro.

Our section of the training is about three weeks, but Wipro does about three to four weeks prior to that before us coming on board. And as I mentioned earlier, we'll have the help desk for supporting people with team staffed. We also have a small group in our call center today who responds to the TRA as well as the other commission complaints. They'll continue to do that and any executive level complaints. We also have in the contract that any complaints that we get we'll use as a feedback loop to our vendor to make any adjustments as necessary.

Just as perspective, I thought it would

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be interesting to see current call volumes, what we've experienced last year and so far this year. As you can see, we had a large spike in volume in January of 2006, from December to January, and it was a colder-than-normal December, a little higher gas prices, and the effect that that had on the customer.

So we really range anywhere from 6,000 phone calls to almost 13,000 in January of 2006. To support that volume of calls, currently we have nine phone people who take inbound calls. We operate 7:00 a.m., to 8:00 p.m., so those folks work shifts that cover those times. We have two people in the backline that do the exceptions. We have one team leader who is there for escalations.

The TRA resolution and emergency leak process, as I mentioned, will not change. We have 28 people who work our leak response line 24 hours a day, seven days a week, and they cover all of our jurisdictions. The credit collections group, we have about half a person who works credit that would be impacted. Important on this slide is that no employees are going to be impacted by this move until February of '07.

We're actually implementing for AGL Resources the BPO in two waves. The first wave will be

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in September, and the second wave will be in February, but we're not letting any employees go until February to make sure that we have stabilization. I mentioned earlier that one of the reasons that we chose this vendor was a guarantee of quality of services improvement.

Today, we answer 80 percent of our phone calls in 120 seconds on average. That's what we staff to. That will remain the same on day one, but within six months, we have contractually agreed to a service level that will answer 80 percent of our calls in 60 seconds and with 18 months, or 12 months later, 80 percent of the calls within 30 seconds. We will be continuing to do our own monthly measurements and reporting specifically on those issues that come through the switch, the phone switch.

We maintain that. We maintain ownership of that. It will stay in the United States. So we'll do our own reporting. We're not relying on the vendor to do that. So we'll be monitoring average speed of answer, hold times, dropped calls, through measures and metrics. They'll also be providing us reports as well. Today, we record 100 percent of our phone calls. We record both the call and the screen shots, and we do a quality monitoring on those calls.

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We will continue to do that today with our own employees. We will continue to do the monitoring. We will also be doing the recording so that we can pull the calls. We'll be recording 100 percent of the calls. And the same level of quality that we have today, based on the same program that we have in place today, is contractually bound to by our vendor, so we'll continue to do that.

We also are required to do no less than ten monitors per CSR per month, which today we do about three. So it's a pretty significant improvement. Our vendor also will be doing their own quality reviews, and we'll be calibrating between the two teams. Part of the training will be that we'll be sending two of our quality personnel to India to train their quality people on our program so that we're all kind of on the same page and looking at the same thing.

The quality incentives are reinforced through service credits, and I'll talk a little more about service credits on the next slide. As I mentioned earlier, Wipro has a quality program that's applied to all business processes. It's not just looking at quality on a call, but it's looking at quality on the overall process, and how can we improve our service to our customer and keep them from having to call us.

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As I mentioned, we'll be responsible for startup training. We do today do end use customer surveys randomly, on a quarterly basis, and we'll continue to do that. And we're required to maintain the same level of service that we have today on this as well. Service level credits. These are goals that we've established. We have about 14 different goals for the customer care service line and several for the engineering construction as well.

If they do not meet the service level, triggers that will result in a financial penalty. Some of the specific service level goals are answering the phone, time to answer, the quality scores on the phone calls, customer satisfaction and response to escalated calls. They have to be responded to within a certain amount of time.

Disaster recovery. This is a bit busy, and I apologize for that. What we're really trying to show here is that we will have lines to India both through New Jersey that will go through the Atlantic and through California that go through the Pacific, so we have automatic redundancy, something that we don't have in our system today. It's an immediate improvement.

The other thing that's not necessarily reflected on this is that within 12 months after going live, we'll also have a second site within India up and running for disaster recovery, again, something we don't have today in our Georgia center. Governance is obviously something we're very concerned about. We look at BPO as an enhancement to our service, not that we're outsourcing and we're going to forget about it.

So we will have an executive steering committee that will be made up of Suzanne Sitherwood, who is president of Chattanooga Gas, as well as her peer, Hank Linginfelter, who is the Senior Vice President of Mid-Atlantic Operations. And then we'll have some other executives. I'll be a part of that as well.

Wipro also has their people that will be in constant communication. Really, we share this with you to let you know that this isn't something that we said, here we have a vendor, we don't have to worry about this anymore. This is very significant to us. And, in fact, both Suzanne Sitherwood, Hank Linginfelter, and I are traveling to India in September before we go live, while we're running parallel, to visit the team, listen to phone calls, and provide feedback directly there while we're there.

Technology. I'll be honest with you. There's no way we'd be doing this today with the

technology we have in our call center today. The CIS system, the customer information system that we have, was implemented in 1992. It's old green screen technology. It's technology that requires a lot of training, six to eight weeks, just to really learn how to navigate through the system.

And we are in the process -- and we started this past weekend -- of the conversion process to implement what we call CMA, which is customer management application. It is something that we've developed internally with a partner. It kind of sits on top of our mainframe. It is web-based, very user friendly, and if a customer calls in and says, I want to do a turn-on, you literally go to the left-hand side of the screen, it has "Turn on," and it walks you through basically a script, very straightforward.

We haven't thought of every scenario. I'm sure there are going to be some questions that we haven't anticipated, but we've been working on this for 18 months and are very proud of this technology. We roll this out. It goes live for Georgia, Atlanta Gas Light and for Chattanooga Gas July 10th. We set a date of migration this past weekend. So with this tool, we'll be able to train in about three weeks.

And what we've been able to do is do a

computer-based training module. We've invested a lot of time and effort into that, which will allow us to do a lot of testing and really make sure that we have clear competence before a representative, whether they're in India or in Georgia or Chattanooga -- we'll be able to test them to make sure of the competence.

We've also put into the computer-based training modules some what we call business basics, just what do you really need to know if you're fresh off the street, what would I need to know if I needed to take phone calls. This system also will eliminate any paper up here. In the top left-hand corner -- it's blurry. I apologize for that. But there's a little place called "My notes," and if any of you have ever walked through a call center, CSRs have a tendency -- in any call center around the world have a tendency to write notes on pieces of paper.

We've eliminated that necessity by putting this note screen up here that allows them to track different things throughout a call. It's not saved, and work goes away. So from a security perspective, we're excited about that. It also only displays the pull-up Social Security number. It only displays the last four digits of anybody's Social Security number.

So we've built some very good security into the system, itself. TDM voice architecture. Some of you may have a lot of telephone experience. I do not. But TDM voice architecture is basically a landline voice architecture. We had a choice to go with TDM or Voice over IP. We did a lot of research internally, had a lot of debates. We listened to calls. We made the choice of TDM. It's a little bit more expensive but a whole lot better quality call.

With the Voice over IP, there was just a little bit of scratchiness, and we just didn't want to put anything into -- of the experience for the customer that was not positive. So we've chosen to go with the TDM voice architecture. And as I mentioned, we'll continue to do all the call recording, do 100 percent of that, and we'll do quite a bit of monitoring. In fact, I mentioned that we have about a 40-person help desk, escalation desk set up.

If they're not getting calls, they'll be pulling calls to listen to them to better document issues and provide that feedback.

That's all I had prepared, and I'd love to answer any questions that you might have.

DIRECTOR KYLE: Well, you talked about that disaster recovery connection, one in the Pacific

and the Atlantic.

MS. REESE: Yes, ma'am.

DIRECTOR KYLE: When is that going to be implemented?

MS. REESE: That goes first. That's how the phone calls will get over there. The second site within India will be implemented 12 months after we go live. So we'll have one site up that gets up and stable as we go live, and then we would implement --

DIRECTOR KYLE: When is that?

MS. REESE: It will be 12 months after we go live, so it will be by the end of 2007.

DIRECTOR KYLE: Okay. Now back to why the U.S. companies did not even bid.

MS. REESE: Our understanding is that they felt that the deal was too small for them to bid on. That was the feedback we got.

DIRECTOR KYLE: Too small economically?

MS. REESE: I'm assuming economically. That's the information that we got back.

DIRECTOR KYLE: So the economics probably kept them from --

MS. REESE: Making it work.

DIRECTOR KYLE: Thank you.

DIRECTOR ROBERSON: I have a few

questions. So the company began exploring the outsource options about a year ago?

MS. REESE: Yes, sir.

DIRECTOR ROBERSON: And you issued the RFP in December of '05?

MS. REESE: Yes, sir.

DIRECTOR ROBERSON: So are all of the customer contacts going to be outsourced? I mean I looked at the list that you had, and I couldn't envision any that weren't covered. So just about every consumer call, customer service call is going to be shifted to India; is that correct?

MS. REESE: Anything except for emergency or leak calls. The safety-related calls are not.

DIRECTOR ROBERSON: What about TTY calls? This is for the deaf when they try to communicate to the company for service issues.

MS. REESE: They will be in scope -- that's part of what the team is on board today. They're literally at our call center today, documenting our processes to make sure that we have those appropriately documented before we take them aboard.

DIRECTOR ROBERSON: You mentioned that service would improve, but was money a part of it as well? I mean is the company going to save money on this outsourcing?

MS. REESE: At first, it will cost us money. But eventually, in the third year, there will be some cost savings.

DIRECTOR ROBERSON: Have you estimated the annual cost savings?

MS. REESE: For Chattanooga specifically? I have not. I'll defer to --

MR. HICKERSON: We do have an estimate. I don't have it with me, but our analysts have prepared an analysis.

DIRECTOR MILLER: Could we get that?

MR. HICKERSON: Yes, we'll get that.

DIRECTOR MILLER: What does the company plan to do with the savings?

MR. HICKERSON: It will be considered in ratemaking as part of the cost of service.

DIRECTOR ROBERSON: Even after the process takes place, before new rates are set? I mean this interim amount of time, what are you going to do with the cost savings during that interim time before rates are recalibrated?

MR. HICKERSON: We'll be filing a rate case before that happens.

DIRECTOR ROBERSON: Well, that's not good.

DIRECTOR KYLE: Excuse me, Dr. Roberson. You're going to file a rate case before the savings are realized?

MR. HICKERSON: Yes, Director. We will be filing a rate case probably before the end of the month.

DIRECTOR KYLE: I'm sorry, Dr. Roberson.

DIRECTOR ROBERSON: Go ahead. Go ahead.

DIRECTOR KYLE: Just the money that it cost to set this up, that would have been part of your business plan anyway.

MS. REESE: Yes, ma'am.

DIRECTOR KYLE: So when you tell us it's going to cost you money, what it's going to do, outsourcing to another country because it's not economically feasible for a U.S. country (sic), you tell us, and you will get it cheaper by going to India and then bringing in money the third year?

MR. HICKERSON: That's correct.

DIRECTOR KYLE: And you're going to file for a rate case before then?

MR. HICKERSON: There's other items involved other than savings. The savings and the cost are not material compared to the other costs.

DIRECTOR KYLE: Dr. Roberson, I apologize. If she could answer too how many Tennesseans are going to lose jobs.

MS. REESE: None. All these calls are taken in Georgia.

DIRECTOR KYLE: Thank you, Dr. Roberson.

DIRECTOR ROBERSON: So the first two years, it's going to increase your costs.

MS. REESE: The first year, there will be an increase in cost. The second year, there's a savings to offset that cost.

DIRECTOR ROBERSON: The second year?

MS. REESE: And then the third year would be when we have a run rate savings.

DIRECTOR ROBERSON: First year, increase; second year, break even; third year, cost reduction.

MS. REESE: Yes, sir.

DIRECTOR ROBERSON: On the service measurements, the quality measurements, it appears that the company has a matrix of measurements that you're

going to be looking at on it.

MS. REESE: Yes.

DIRECTOR ROBERSON: And those are going to be on a monthly basis? The company will get those on a monthly basis?

MS. REESE: We will get those on a monthly basis, and we'll monitor them daily. Average speed of answer, we can monitor daily. Quality, we can monitor, so if we see a trend going a negative way, we can react to that fairly quickly.

DIRECTOR ROBERSON: So are these service standards that you would voluntarily share with the Authority on a monthly basis so that we could, as well, monitor the service? So the company would agree to provide those to our Consumer Services Division?

MS. REESE: Yes.

DIRECTOR ROBERSON: Okay. That's all for now.

CHAIRMAN JONES: I have a couple of questions. One main one. On the financial penalties, are those penalties imposed by AGL on the vendor for failure to meet certain metrics?

MS. REESE: Yes, sir. They were agreed to, and they're contractually bound to.

CHAIRMAN JONES: When those penalties

occur, how is that money accounted for, or how do you anticipate it will be accounted for?

MS. REESE: It depends on the service level credit. Of the four that I showed you -- there's multiple, but of the four that I showed you, two are by -- at a company level. And then others are more of a blended rate, so it depends on how they come through. If they were to come through directly for Chattanooga, it would go directly back to Chattanooga.

CHAIRMAN JONES: Would Chattanooga then book that as a credit for the rate payers? These would be penalties for failure to meet metrics that -- for not performing well. And these would be costs that would have been in your rates at a certain level, but you'll be getting a credit back which, in effect, reduces that expense that you would have initially had.

MS. REESE: Yes.

MR. HICKERSON: Hopefully, we will not be collecting a lot of those credits.

MS. REESE: Believe me, they don't want to pay them. So they have a lot of incentive to be able to achieve the service level.

MR. HICKERSON: The reason for them is to ensure the vendor does live up to the contract. And if we are imposing those penalties, it means that

they're not, so we do not want that to happen.

MS. REESE: That's right.

CHAIRMAN JONES: After February 7th, how many employees do you think you're going to lose?

MS. REESE: Including our emergency response team, our escalation team, the group that supports customer relations is what we call -- it's really the group that takes care of executive complaints and regulatory complaints. We also have a small group in Georgia that supports the marketers. Then we have a support group that does quality and training. We'll have about 100 people. We have about 240 people today.

CHAIRMAN JONES: After February 7th, the attrition will be about 100 people?

MS. REESE: We will have remaining about 100 people. We will have attritted about 140.

CHAIRMAN JONES: About 140. And that's all on the backline functionality part?

MS. REESE: It's backline and phones. We'll have some phones.

CHAIRMAN JONES: And you'll hire that many people in India? Is that how it works?

MS. REESE: It's basically that. We have not asked them to provide a number of people. What we've contractually agreed to was we want this level of

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service, and we've agreed to a price. So if for some reason they need more people, that's on their dime. They've estimated about the same number of people that we have today.

CHAIRMAN JONES: Thank you. Very interesting.

DIRECTOR MILLER: You mentioned that you currently answer 80 percent of your calls at an average of 120 seconds?

MS. REESE: Yes, sir.

DIRECTOR MILLER: Then you plan it to drop in six months to -- under the contract, six months to 60 and 18 months to 30?

MS. REESE: Yes, sir.

DIRECTOR MILLER: What would be the averages for 100 percent of the calls?

MS. REESE: The way a call center is measured is not at 100 percent, so --

DIRECTOR MILLER: But you do keep -- record that. You don't record that?

MS. REESE: Well, we do record 100 percent of our calls, but we don't really measure how long it takes to answer 100 percent of our calls. That's kind of a strange answer.

DIRECTOR MILLER: I want to know what

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the rate is for January of '06. I mean that's when the calls are.

MS. REESE: Yes, and I don't have that information. Our target was the 80, 120, but I can't tell you exactly how we performed. I don't have that with me today. But we can provide that to you, if you'd like that information.

DIRECTOR MILLER: Okay. Well, frankly, I don't like it. I don't like it. I'd like the jobs to stay in the United States, preferably in Tennessee. But if we're going to remain players in a global economy, we have to make these kind of decisions, and I appreciate what the company is going through.

MS. REESE: It was a very difficult decision. Hopefully, our customers will see a benefit from it.

DIRECTOR ROBERSON: You have a franchise with the City of Chattanooga for sure to provide services. Have you discussed this change in service with city officials?

MS. REESE: I personally have not. I'm not aware that we have.

DIRECTOR ROBERSON: I think it would be a good idea to discuss this with the mayor's office to at least let them know that the company is doing this in

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an effort to try to economize.

MS. REESE: We can certainly do that.

DIRECTOR ROBERSON: And I agree with Director Miller. You know, it's a hard pill to swallow because I too would prefer the jobs to stay in the United States. And I just would like for the company to know and for your outsourcer to know that with these reports, we're going to be watching. And if we begin getting a large number of complaints, we'll ask the company to come back in here and address those problems.

So we're going to be monitoring this closely, as is our statutory obligation to ensure quality of service by utilities.

MS. REESE: I understand that, and we appreciate that. Anything else?

DIRECTOR KYLE: You've done an excellent job for your company. I do agree with Commissioner Miller and Commissioner Roberson. We send our kids off to college, hoping they'll come back home. Now I'm going to have to send them over there hoping they'll have a job. And this is tough. This is now nationwide. And I'm sure y'all have considered that. Maybe the pendulum will swing back.

MS. REESE: Maybe so. Thank you very much. I appreciate your time today. Thank you.

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DIRECTOR KYLE: We appreciate you.

(Proceedings concluded at 2:43 p.m.)

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REPORTER'S CERTIFICATE

STATE OF TENNESSEE)
COUNTY OF DAVIDSON)

I, Carol A. Nichols, Registered Diplomate Reporter, Certified Realtime Reporter, and Certified Court Reporter, with offices in Nashville, Tennessee, hereby certify that I reported the foregoing proceedings at the time and place set forth in the caption thereof; that the proceedings were stenographically reported by me in shorthand; and that the foregoing proceedings constitute a true and correct transcript of said proceedings to the best of my ability.

I FURTHER CERTIFY that I am not related to any of the parties named herein, nor their counsel, and have no interest, financial or otherwise, in the outcome or events of this action.

IN WITNESS WHEREOF, I have hereunto affixed my official signature and seal of office, this 28th day of June, 2006.

CAROL A. NICHOLS, REGISTERED DIPLOMATE REPORTER, CERTIFIED REALTIME REPORTER, CERTIFIED COURT REPORTER, AND NOTARY PUBLIC FOR THE STATE OF TENNESSEE

My Commission Expires:
February 5, 2008

Summary of CGC Proposed Service Metrics CAPD Exhibit MDC SQ

(As Reported by Nashville Gas to CAPD)

05-00258

Call Center:

- # of Calls received
- % answered
- Average Speed of answer (Minutes)
- Length of Call (Minutes)
- After Call Processing Time

Service Department:

- Orders Worked
- Appointment Orders
- Appoints Missed
- Emergency Orders
- Emergency Response (Minutes)*
- Meters Set
- Appliance Installment

Construction Department:

- TN 1 Call Tickets
- Service Orders Received
- Service Orders Installed
- Backlog (Weeks)
- Damages
- Service renewal/Relocate**
- Service Retired**
- Survey Leaks

Meter Services:

- # Meters Read
- Risers Inspected
- Estimates
- % Estimated
- Skips
- Re-reads
- Door Tags

Note:

* = Emergency Response Time= Total minutes from time dispatched to arrival on site
** = Does not include services renewed or retired from castiron / bare steel main replacement program

RULES
OF THE
GEORGIA PUBLIC SERVICE COMMISSION
515-7 GAS UTILITIES

CHAPTER 515-7-7
SERVICE QUALITY STANDARDS FOR THE ELECTING DISTRIBUTION COMPANY

TABLE OF CONTENTS

515-7-7-.04 Service Quality Standards: Customer Service, Billing, and Metering.
Every EDC shall be required to meet service quality standards to ensure high quality service to natural gas customers, including marketers, in Georgia in regards to customer service, billing, and metering. Specifically, every EDC shall assure that:

d. The call center response times shall not fall below the established benchmarks.

Authority Ga. Law: O.C.G.A. § 46-4-158.1(a)(1).

515-7-7-.05 Service Quality Standards: Marketer Services
Every EDC shall be required to meet service quality standards to improve the efficiency of the marketer services that are offered to all certified marketers. In addition, these same services quality standards shall also apply to services provided by the EDC to the Regulated Provider, unless the Commission specifically provides otherwise. Specifically, every EDC shall assure that:

f. The call center response time to marketers shall not fall below the established benchmark; and

Authority Ga. Law: O.C.G.A. § 46-4-158.1(a)(1).

Electing Distribution Company Service Quality Measure Compliance Report

AVERAGE TWO-MONTH MEASURES	2003			2004						2005						2006		
	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun
METER READING ACCURACY	99 60%	99 69%	99 73%	99 61%	99 46%	99 51%	99.58%	99 74%	99 69%	99 69%	99 67%	99 65%	99 73%	99 81%	99 64%	99 44%	#DIV/0!	#DIV/0!
Firm Meter Readings Issued	2,939,183	2,920,427	2,964,825	3,093,832	3,041,773	2,990,994	2,943,295	2,932,116	2,978,009	3,054,167	3,072,312	3,014,964	2,974,024	2,961,887	3,010,389	3,074,402		
Firm Meter Readings Canceled	9,276	6,426	5,036	8,452	13,659	10,913	9,326	5,529	5,406	5,196	7,875	7,383	4,761	2,829	7,020	9,276		
NCONS	2,382	2,734	3,081	3,693	2,841	3,864	2,965	2,187	3,724	4,173	2,199	3,122	3,316	2,705	3,681	7,942		
	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun
METER READING TIMELINESS	99 92%	99 91%	99 90%	99 88%	99 91%	99 87%	99 90%	99 93%	99 87%	99 86%	99 93%	99 90%	99 89%	99 91%	99 88%	99 74%	99 87%	#DIV/0!
Number of Timely Meters Read	2,936,801	2,917,693	2,961,744	3,090,139	3,038,932	2,987,130	2,940,330	2,929,929	2,974,285	3,049,994	3,070,113	3,011,842	2,970,708	2,959,182	3,006,708	3,066,460	3,073,484	
Total Number of Meters Read	2,939,183	2,920,427	2,964,825	3,093,832	3,041,773	2,990,994	2,943,295	2,932,116	2,978,009	3,054,167	3,072,312	3,014,964	2,974,024	2,961,887	3,010,389	3,074,402	3,077,495	
	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun
APPOINTMENT ATTAINMENT	96.72%	94 42%	92 54%	95 56%	95 18%	94 19%	95 33%	93 53%	90 85%	95 57%	96 89%	95 59%	95 46%	91 44%	90 32%	94 56%	94 58%	#DIV/0!
Total Number of Scheduled Appointments	60,626	77,640	79,820	60,182	62,618	64,731	67,535	79,669	96,926	68,822	61,392	63,803	67,571	79,952	94,168	63,160	59,345	
Number of Scheduled Appointments Met	58,639	73,309	73,864	57,509	59,597	60,971	64,383	74,511	88,061*	65,772	59,482	60,992	64,504	73,112	85,057	59,723	56,131	
EBB AVAILABILITY	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun
Total Hours in Month	1,488 00	1,464 00	1,464 00	1,440 00	1,464 00	1,464 00	1,488 00	1,464 00	1,464 00	1,416 00	1,464 00	1,464 00	1,488 00	1,464 00	1,464 00	1,416 00	1,464 00	
Customer Information System	98.73%	98 83%	99.73%	99 68%	98 94%	99 14%	99 63%	99.68%	99 43%	98 44%	99 82%	99 77%	99 93%	100 00%	100 00%	94 92%	99 66%	#DIV/0!
Hours of Scheduled Maintenance	348 00	340 25	342 75	332 25	335 00	350 50	348 00	342 75	318 25	327 00	335 00	348 00	342 75	342 75	314 00	327 00	335 00	
Hours of Unplanned Outages	14 52	13 14	3 00	3 50	12 00	9 58	4 23	3 60	6 55	17 00	1 98	2 60	0 78	0 05	0 00	55 33	3 79	
Gas Operating System	99 96%	99 66%	100 00%	100 00%	99 96%	99 81%	100 00%	99 91%	100 00%	100 00%	99 99%	99 95%	99 95%	100 00%	100 00%	98 51%	100 00%	#DIV/0!
Hours of Scheduled Maintenance	126 00	119 00	120 00	119 00	119 00	126 00	119 00	126 00	119 00	110 50	117 00	110 50	117 00	110 50	117 00	110 50	117 00	
Hours of Unplanned Outages	0 50	4 58	0 00	0 00	0 50	2 58	0 00	1 25	0 00	0 00	0 17	0 67	0 67	0 00	0 00	19 50	0 00	
Marketer interface Application	99 96%	99 81%	100 00%	100 00%	99 55%	99 81%	99 97%	99 10%	100 00%	99 68%	100 00%	100 00%	100 00%	99 78%	100 00%	95 75%	100 00%	#DIV/0!
Hours of Scheduled Maintenance	126 00	119 00	120 00	125 00	119 00	120 00	125 00	126 00	119 00	123 00	117 00	127 00	123 00	126 00	117 00	123 00	117.00	
Hours of Unplanned Outages	0 50	2 58	0 00	0 00	6 00	2 58	0 35	12 00	0 00	4 17	0 00	0 00	0 00	3 00	0 00	55 00	0 00	
Eneract	98 95%	99 25%	100 00%	99 74%	99 37%	99 61%	99 69%	99 77%	99 51%	99 73%	99 85%	99 88%	99 94%	100 00%	100 00%	95 75%	99 72%	#DIV/0!
Hours of Scheduled Maintenance	126.00	119 00	120 00	119 00	119 00	120 00	125 00	119 00	119 00	121 00	117 00	127 00	123 00	123 00	117 00	121 00	117 00	
Hours of Unplanned Outages	14 26	10 14	0 00	3 50	8 50	5 18	4 23	3 10	6 55	3.50	1 98	1.60	0 78	0 05	0 00	55.00	3.79	
	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun	Jul-Aug	Sep-Oct	Nov-Dec	Jan-Feb	Mar-Apr	May-Jun
RESPONSIVENESS TO THE COMMISSION	100 00%	100 00%	100 00%	100 00%	100 00%	100.00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	#DIV/0!
Total Urgent/Non-urgent Complaints	14	23	30	23	44	19	13	5	25	25	17	12	19	27 00	40 00	36	32	
Number Acknowledged in One/Five Day(s)	14	23	30	23	44	19	13	5	25	25	17	12	19	27 00	40 00	36	32	

MONTHLY MEASURES	2003						2004											
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug*	Sep	Oct	Nov	Dec
CALL CENTER RESPONSE TIME	92 79%	92 70%	91 21%	96 18%	95 60%	93 59%	96 98%	94 41%	93 90%	89 36%	84 87%	91 44%	96 88%	96 34%	92 76%	94 14%	90 82%	87 48%
Total Number of Calls	91,845	91,200	98,371	121,311	106,629	119,193	96,740	96,695	100,745	90,663	85,936	86,173	57,035	44,683	46,421	51,914	64,115	62,029
Number of Calls answered in 180 seconds	85,222	84,542	89,724	116,677	101,937	111,553	93,818	91,290	94,600	81,016	72,934	78,797	55,256	43,048	43,060	48,872	58,229	54,263
FORECASTING	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Firm Demand Forecast Accuracy	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%
Number of Days	31	31	30	31	30	31	31	29	31	30	31	30	31	31	30	31	30	31
Number of Days Followed Process	31	31	30	31	30	31	31	29	31	30	31	30	31	31	30	31	30	31
Monthly Net Percentage	-0 02%	0 55%	-0 24%	-2.27%	-3 43%	-1.76%	-1 78%	2 27%	1 56%	2 65%	-1 86%	1.70%	-0.55%	-0 55%	-1 63%	0 23%	0 28%	-0 20%
Forecast Demand	4,247,763	4,183,981	4,319,178	6,498,659	12,005,828	29,577,784	30,717,213	28,135,314	12,570,514	8,546,368	5,236,442	4,446,041	4,154,619	4,323,946	4,406,058	5,535,690	12,743,963	27,617,127
Actual Demand	4,248,455	4,160,765	4,329,437	6,646,178	12,417,693	30,098,913	31,263,498	27,495,673	12,374,909	8,320,053	5,333,729	4,370,591	4,177,662	4,347,619	4,477,746	5,523,166	12,708,310	27,671,675

*Appointment Attainment - Nov-Dec 2004 revised Feb 2005, Number of scheduled appointments met changed from 88,180 (90.98%) to 88,061 (90.85%), which is still in compliance with our benchmark.

*Call Center Response Time - August 3, 2004 is missing due to a technology failure.

	2005												200					
	Jan	Feb	Mar	Apr	May	Jun*	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun*
CALL CENTER RESPONSE TIME	88 53%	95 80%	96 61%	95 55%	95 95%	94 21%	93 87%	90 61%	91 27%	80 20%	86 63%	88 69%	85 42%	81 19%	86 07%	92 57%	#DIV/0!	#DIV/0!
Total Number of Calls	56,927	46,475	46,502	39,539	38,838	38,685	35,280	41,388	41,504	63,032	60,413 00	57,364	56,412	50,038	50,439	38,468		
Number of Calls answered in 180 seconds	50,397	44,523	44,926	37,779	37,265	36,445	33,117	37,502	37,880	50,552	52,336 00	50,877	48,188	40,626	43,413	35,610		
FORECASTING	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Firm Demand Forecast Accuracy	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	96 67%	100 00%	100 00%	100 00%	100 00%	100 00%	#DIV/0!	#DIV/0!
Number of Days	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30		
Number of Days Followed Process	31	28	31	30	31	30	31	31	30	31	29	31	31	28	31	30		
Monthly Net Percentage	4 37%	4 51%	-0 80%	-0 31%	1 82%	3 05%	2 36%	-0 28%	-0 19%	-2 96%	3 42%	1 01%	3 40%	-2 90%	-3 45%	what	#DIV/0!	#DIV/0!
Forecast Demand	26,606,685	21,506,281	18,197,644	8,344,012	5,919,598	4,580,813	4,272,122	4,256,709	4,199,034	7,216,795	14,295,368	28,848,508	21,152,747	21,645,042	13,649,085	5,954,831		
Actual Demand	25,444,755	20,536,863	18,342,439	8,369,915	5,811,896	4,441,183	4,171,352	4,268,707	4,206,988	7,430,099	13,806,281	28,556,431	20,434,006	22,273,493	14,119,299	6,034,345		

*Call Center Response Time - June 2005 was revised Sept. 2005, changed from 94.23% to 94.21%, which is still in compliance with our benchmark.

Electing Distribution Company Service Quality Measure Compliance Report

MONTHLY MEASURES	2005												
LEAK RESPONSE TIME	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Average
Average FSR Leak Response Time	28.7	28.0	28.1	26.7	38.7	26.1	27.1	27.2	27.9	29.8	30.0	28.8	29.0
Average Distribution Leak Response Time	33.7	33.9	36.4	36.2	34.5	34.9	34.5	36.1	35.5	34.2	33.2	35.2	34.9

Electing Distribution Company Service Quality Measure Compliance Report (Addendum)

MONTHLY MEASURES	2003						2004											
	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug*	Sep	Oct	Nov	Dec
CALL CENTER RESPONSE TIME																		
Average Speed of Answer	31	34	39	18	20	31	15	26	28	43	59	34	12	11	22	19	30	43
Number Calls Offered	91,845	91,200	98,371	121,311	106,629	119,193	96,740	96,695	100,745	90,663	85,936	86,173	57,035	44,683	46,421	51,914	64,115	62,029
Number of Calls Abandoned	2,878	2,827	3,798	2,367	2,454	3,583	1,617	2,828	2,903	3,756	4,457	2,721	1,055	830	1,739	1,589	2,609	3,319
Percentage of Calls Abandoned	3.13%	3.10%	3.86%	1.95%	2.30%	3.01%	1.67%	2.92%	2.88%	4.14%	5.19%	3.16%	1.85%	1.86%	3.75%	3.06%	4.07%	5.35%

*Call Center Response Time - August 3, 2004 is missing due to a technology failure.

MONTHLY MEASURES	2005											
	Jan	Feb	Mar	Apr	May	Jun*	Jul	Aug	Sep	Oct	Nov	Dec
CALL CENTER RESPONSE TIME												
Average Speed of Answer	38	15	14	15	15	19	22	33	30	73	46	42
Number Calls Offered	56,927	46,475	46,502	39,539	38,838	38,685	35,280	41,388	41,504	63,032	60,413	57,364
Number of Calls Abandoned	3,045	898	819	1,005	850	1,122	1,037	1,742	1,563	5,205	3,026	2,306
Percentage of Calls Abandoned	5.35%	1.93%	1.76%	2.54%	2.19%	2.90%	2.94%	4.21%	3.77%	8.26%	5.01%	4.02%

MONTHLY MEASURES	2006											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CALL CENTER RESPONSE TIME												
Average Speed of Answer	53	70	54	28								
Number Calls Offered	56,412	50,038	50,439	38,468								
Number of Calls Abandoned	3,013	3,253	2,254	956								
Percentage of Calls Abandoned	5.34%	6.50%	4.47%	2.49%	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

*Call Center Response Time - June 2005 was revised Sept. 2005, changed from 2.82% to 2.90%, which is still in compliance with our benchmark.

Elizabethtown (NUI) Service Metrics and Reporting

Letter to New Jersey PSC dated March 31, 2006

1	Emergency Response Time	Company just respond to to 95% of calls within 45 minutes over a calendar year
2	Call Center Response	The Company must answer 80% of all calls offered to a represetnative with 60 seconds over a calendar year
3	Appointment Attainment	The Company shall meet 90% of all scheduled appointments over a calendar year period
4	Meter Reading Accuracy	By the end of 20006, Eliabethtown (NUI) will be able to obtai actual meter reads for __% of all accounts billed
5	Employee Safety	Using calendar year 2004 as the baseline, Elizabethtown's OSHA recordable injuries and illnesses declined from 50 to 24 in 2005, a 52% decline. Total injury claims dropped from 68 to 37
6	Cmplaints To The Board	Using calendar year 2004 as a baseline, compllaints dropped from __ to __ in 2005, a __ % .decline

March 31, 2006

Honorable Kristi Izzo, Secretary
State of New Jersey
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102

**RE: I/M/O The Petition Of NUI Utilities, Inc. d/b/a Elizabethtown Gas Company And AGL Resources Inc. For Authority Under *N.J.S.A.* 48:2-51.1 And *N.J.S.A.* 48:3-10 of a Change In Ownership And Control
Docket No. GM04070721**

Dear Secretary Izzo:

Enclosed for filing are an original and ten copies of this letter and the Proposed Service Standards of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company ("Elizabethtown" or "Company"). Under the Board of Public Utilities' ("Board") November 17, 2004 Order approving the acquisition of Elizabethtown by AGL Resources Inc. required Elizabethtown to identify various service standards in the area of safety, reliability and customer service. The Board's Order required the Company to work with Board Staff and the Division of the Ratepayer Advocate to establish the appropriate baseline measures against which the Company will measure subsequent performance.

Elizabethtown has held a number of meetings with, and provided information to, the Staff and the Ratepayer Advocate concerning these matters. While the Company cannot represent that consensus has been achieved on all issues, the Company believes that the attached standards provide a reasonable baseline for the Company to measure its performance against until its next base rate case which will be filed in 2009.

The attached standards measure Elizabethtown's performance in a number of critical areas including: (1) safety and reliability; (2) customer satisfaction, (3) customer service, (4) operational efficiency, (5) employee safety, and (6) customer complaints. The specific measurements to be performed and standards (where applicable) are:

1. Measurement of odor, leak and emergency response time – Standard – Company must respond to 95% of calls within 45 minutes over a calendar year period;

2. Call Center Response – The Company must answer 80% of all calls offered to a representative within 60 seconds over a calendar year period;

3. Appointment Attainment – The Company shall meet 90% of all scheduled appointments over a calendar year period;

4. Meter Reading Accuracy – By the end of 2006, Elizabethtown will be able to obtain actual meter reads for __% of all accounts billed;

5. Employee Safety – Using calendar year 2004 as the baseline, Elizabethtown's OSHA recordable injuries and illnesses declined from 50 to 24 in 2005, a 52% decline. Total injury claims dropped from 68 to 37; and

6. Complaints To The Board – Using calendar year 2004 as a baseline, complaints dropped from __ to __ in 2005, a __% decline.

Under the Board's November 17, 2004 Order, the proposed standards are to be made available to other parties for comment. In the event that there is no opposition, these standards shall remain in effect until the Company's next rate case or such time as the Board adopts generic standards for gas utilities.

Kindly acknowledge receipt and filing of the enclosures by date stamping the enclosed copy of this letter and returning it to our messenger. Please contact the undersigned if you have any questions.

Yours truly,

Mary Patricia Keefe
Director - Regulatory Affairs

cc: Service List

CAPD Exhibit MDC- SQT

Chattanooga Gas Company
TRA FG Item No 28
Attachment A
6/1/2006

	DEFINITION OF THE METRIC	DETAIL	JAN 2004	FEB 2004	MAR 2004	APR 2004	MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	2004 YTD
Customers			61,072	61,379	61,332	60,885	60,108	59,339	58,985	58,835	58,633	59,180	60,188	61,342	60,124
Order Success	Number of completed hard orders divided by number of total hard orders		92%	94%	96%	94%	93%	97%	95%	95%	95%	93%	95%	97%	95%
Overall Appointment Attainment	Number of hard order appointments met divided by number of total hard order appointments taken	Overall	95.8%	97.0%	97.4%	98.4%	97.5%	97.1%	97.6%	97.7%	96.2%	88.2%	88.3%	94.3%	95.3%
		4 Hour	96.0%	95.6%	95.6%	96.6%	96.3%	98.6%	98.7%	98.1%	97.9%	90.8%	94.4%	94.5%	96.0%
		8 Hour	93.1%	97.1%	97.8%	95.3%	98.3%	95.4%	95.9%	96.4%	92.6%	81.9%	81.6%	91.8%	93.9%
Meter Reading Accuracy	Firm Meter Readings Issued minus Firm Meter Readings Canceled minus NCONS divided by Firm Meter Readings Issued		99.86%	99.69%	99.41%	99.56%	99.51%	99.45%	99.60%	99.58%	99.69%	99.77%	99.87%	99.80%	99.66%
Meter Reading Timeliness	Number of Timely Meters Read divided by Total Number of Meters Read		99.73%	99.79%	99.60%	99.84%	99.75%	99.74%	99.86%	99.83%	99.73%	99.62%	99.60%	99.89%	99.72%
Average Leak Response Minutes	Average First Response to Leak Call		26.6	25.4	24.5	28.8	27.4	25.8	27.2	25.8	25.5	25.3	26.2	26.3	26.1
Third Party Damages	3rd Party Damages - An occurrence of an outside party damaging a gas facilities while excavating				108			159			149			61	477
TRA complaints			2	1	0	3	0	2	10	1	1	1	1	1	23
Polaris Customer Survey		CSR (Top 3)	89%		No Survey		96%		95%		84%		95%		
		FSR (Top 3)	97%		* *		99%		96%		96%		95%		
New Meters Approved	A final approved meter is one that has been designed (approved) by engineering and is ready to be contracted with the customer.		120	278	400	418	231	362	529	311	341	293	249	430	3962
New Meters Installed			171	117	136	205	79	89	109	157	158	137	155	182	1695
Number of Calls Answered			10,058	10,442	10,957	9,457	7,432	7,010	5,970	5,933	8,133	7,859	8,437	8,690	
Number of Calls offered			10,194	10,716	11,269	9,832	7,822	7,287	6,058	6,021	8,256	7,996	8,786	9,005	
% answered within 120 seconds			95.47%	80.23%	88.77%	87.22%	82.31%	87.73%	95.89%	96.81%	93.69%	94.41%	87.34%	86.42%	
Average Time to Connect			14	27	26	35	49	33	12	10	18	15	35	34	
# Abandoned Calls			135	276	332	375	390	277	86	88	123	137	349	315	
% Abandoned Calls			1.3%	2.6%	2.9%	3.8%	5.0%	3.8%	1.4%	1.5%	2.0%	1.7%	4.0%	3.5%	

	DETAIL	JAN 2005	FEB 2005	MAR 2005	APR 2005	MAY 2005	JUN 2005	JUL 2005	AUG 2005
Customers		61,856	62,386	62,464	62,360	61,145	60,427	59,882	59,828
Order Success		96%	96%	95%	97%	97%	98%	99%	97%
Overall Appointment Attainment	Overall	95.4%	97.6%	98.2%	98.4%	98.5%	98.4%	98.7%	96.7%
	4 Hour	92.7%	98.3%	97.4%	99.3%	98.7%	98.4%	97.9%	97.0%
	8 Hour	95.2%	98.4%	98.0%	96.2%	97.5%	98.9%	99.2%	95.8%
Meter Reading Accuracy		99.29%	99.36%	99.26%	99.04%	97.51%	97.92%	99.02%	99.35%
Meter Reading Timeliness		99.81%	99.88%	99.86%	99.89%	99.76%	99.83%	99.76%	99.75%
Average Leak Response Minutes		25.2	26.0	23.6	25.7	22.1	24.4	23.7	25.1
Third Party Damages				86			81		
TRA complaints		4	1	3	3	3	1	2	1
Polaris Customer Survey	CSR (Top 3)	86%		95%		91%		96%	
	FSR (Top 3)	97%		96%		96%		96%	
New Meters Approved		226	308	261	140	26	220	168	336
New Meters Installed		186	114	136	106	99	110	100	96
Number of Calls Answered		11,174	10,704	11,381	10,727	9,872	7,337	5,680	5,791
Number of Calls offered		11,708	11,028	11,631	11,053	10,058	7,542	5,956	6,068
% answered within 120 seconds		82.82%	89.95%	92.62%	90.80%	93.70%	91.50%	86.30%	82.96%
Average Time to Connect		43	25	19	22	16	22	33	42
# Abandoned Calls		534	324	250	326	186	205	276	277
% Abandoned Calls		4.6%	2.9%	2.1%	2.9%	1.8%	2.7%	4.6%	4.6%

Chattanooga Gas Company
TRA FG Item No 28
Attachment A
6/1/2006

	DEFINITION OF THE METRIC	DETAIL	SEP 2005	OCT 2005	NOV 2005	DEC 2005	YTD	JAN 2006	FEB 2006	MAR 2006	APR 2006	MAY 2006	JUN 2006	
Customers			59,808	58,921	60,815	61,988	61,074	62,323	62,447	62,385	61,888			
Order Success	Number of completed hard orders divided by number of total hard orders		98%	96%	95%	96%	97%	97%	97%	97%	94%			
Overall Appointment Attainment	Number of hard order appointments met divided by number of total hard order appointments taken	Overall	97.0%	87.2%	87.3%	94.1%	95.8%	97.2%	95.8%	97.1%	97.6%			
		4 Hour	98.1%	85.9%	86.1%	93.4%	95.2%	97.6%	94.3%	95.2%	96.4%			
		8 Hour	96.7%	83.8%	84.2%	91.3%	94.4%	95.3%	93.9%	97.5%	96.9%			
Meter Reading Accuracy	Firm Meter Readings Issued minus Firm Meter Readings Canceled minus NCONS divided by Firm Meter Readings Issued		98.41%	98.57%	99.09%	99.44%	99.02%	98.28%	98.54%					2 month lag in reporting
Meter Reading Timeliness	Number of Timely Meters Read divided by Total Number of Meters Read		98.77%	98.76%	99.37%	98.76%	98.68%	98.82%	98.82%					2 month lag in reporting
Average Leak Response Minutes	Average First Response to Leak Call		24.9	27.3	25.5	28.4	26.0	24.5	22.7	23.0	24.0			
Third Party Damages	3rd Party Damages - An occurrence of an outside party damaging a gas facilities while excavating		72			64	303			34				
TRA complaints			1	1	3	1	24	1	1	0	1			
Polaris Customer Survey		CSR (Top 3)	98%		94%			93%						
		FSR (Top 3)	96%		97%			99%						
New Meters Approved	A final approved meter is one that has been designed (approved) by engineering and is ready to be contracted with the customer.		344	358	76	10	2477	160	141	185	175			
New Meters Installed			103	112	161	165	1486	115	115	80	103		0	
Number of Calls Answered			5,942	8,288	8,200	8,495		12,383	10,130	10,108	8,368			
Number of Calls offered			6,251	9,931	8,538	9,935		12,978	10,814	10,387	8,551			
% answered within 120 seconds			84.87%	53.52%	85.76%	88.81%		80.87%	80.53%	89.51%	93.31%			
Average Time to Connect			38	181	35	31		52	54	28	18			
# Abandoned Calls			309	1843	338	440		595	484	278	183			
% Abandoned Calls			4.9%	18.5%	4.0%	4.4%		4.6%	4.6%	2.7%	1.9%			