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September 5, 2006

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VIA ELECTRONIC MAIL AND HAND DELIVERY

Chairman Sara Kyle
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-00505

Re: Docket 06-00175 Petition of Chattanooga Gas Company to Increase Rates, Including a Comprehensive Rate Design Proposal and Revised Tariff

Dear Chairman Kyle:

Chattanooga Gas Company ("CGC") is filing in the above-referenced matter an original and four (4) copies of its Responses to certain discovery requests issued by the Consumer Advocate and Protection Division ("CAPD") on August 11, 2006. Included are responses to the following questions: 1-10, 12-18, 20, 22-26, 28-35, 50-53, 55-76, 78-79, 81, 95-104, and 106-109. CGC's responses to Nos. 5, 7(e), 14, and 78 contain Confidential Information and are being filed under protective seal pursuant to the Protective Order entered in this matter on August 24, 2006. CGC will respond to the CAPD's remaining discovery requests on or before the deadline established by the Hearing Officer at the August 23, 2006 Status Conference.

Sincerely yours,

Jennifer L. Brundige

Enclosures

cc: Tim Phillips, Esq.
Henry Walker, Esq.
David C. Higney, Esq.

DISCOVERY REQUEST NO. 1:

For the years 2000 through 2006 provide:

(A) CGC's annual earnings;
(B) The date of each formal dividend declaration made by CGC;
(C) For each declaration provide the total dollar amount of dividends declared and the dividends declared per share; and
(D) If CGC paid dividends without making a formal declaration of dividends then provide the annual amount paid and identify the party receiving the dividends.

Response:

(A) CGC's annual earnings 2000 – 2006 are as follows:

FY 2000 – $4,097,321
FY 2001 – $6,367,321
Stub 2001 – $3,152,314
CY 2002 – $7,004,660
CY 2003 – $6,025,807
CY 2004 – $9,036,223
CY 2005 – $6,330,473
CY 2006 – $3,713,950 (through July 31, 2006)

FY = 12 month period ended September 30th
Stub = 3 month period ended December 31, 2001
CY = 12 month period ended December 31st

(B) Formal declaration of dividends has not been made between 2000-2006.

(C) N/A per response to (B) above.

(D) All dividends are paid to AGL Resources Inc., the sole shareholder of CGC. Prior to the year ended September 30, 2001, CGC did not pay a shareholder dividend. For the year ended September 30, 2001, CGC paid an annual dividend. Subsequent to September 30, 2001, CGC paid, and will continue to pay, where not restricted by applicable rules and regulations, a quarterly dividend based on earnings. The annual dividend amounts paid from 2000 – 2006 are as follows:

2000 – No dividend paid
2001 – $5,620,114
2002 – $4,182,725
2003 – $4,636,039
2004 – $6,907,194
2005 – $4,105,836
YTD 2006 – $4,559,953

DISCOVERY REQUEST NO. 2:

Provide the dollar amount of dividends expected to be declared or paid out by CGC in the attrition year.

Response:

The dividend amount expected to be paid out by CGC during the attrition period is approximately $2.5 million. The dividend, if made, will be paid to AGL Resources Inc.

DISCOVERY REQUEST NO. 3:

Provide the amount of capital paid in or expected to be paid in by AGL Resources to CGC in the attrition year.

Response:

No capital has been paid or is expected to be paid in by AGL Resources to CGC in the attrition year.

DISCOVERY REQUEST NO. 4:

Produce copies of any and all documents referred to or relied upon in responding to the Attorney General's discovery requests.

Response:

To the best of its knowledge, the Company has already produced or will produce all such documents in its pre-filed testimony and exhibits filed June 30, 2006, its responses to the minimum filing guidelines, and its responses to the CAPD's, Staff's and CMA's discovery requests. To the extent CGC identifies additional documents or additional issues arise, CGC will supplement the appropriate filing or response prior to the hearing on the merits and/or include such information in its pre-filed rebuttal testimony.

DISCOVERY REQUEST NO. 6:

Provide a reconciliation of Shared Service Allocation expense reported on the PSC Forms 3.03 filed with the TRA and forms U-9/C-3 or other similar document filed with the SEC for the past five years.

Response:

The "Shared Service Allocation" cost is reported in the SEC Form U-13-60. The costs are included in the report titled "Analysis of Billing - Associate Companies." A reconciliation between the PSC Forms 3.03 and the U-13-60 is provided in the attached schedule CAPD 6-1 for the following U-13-60 filings:

- The nine months ending September 30, 2001
- The three months ending December 31, 2001
- The twelve months ending December 31, 2002
- The twelve months ending December 31, 2003
- The twelve months ending December 31, 2004

AGL Services Company has made no other U-13-60 or similar filings with the SEC.

These filings can be obtained on the internet at **sec.gov** as follows:

1. On the main web page under "Filings and Forms (EDGAR)", click on "Search for Company Filings."
2. On the "Search for EDGAR Database" page, go to "Companies and Other Filers."
3. In the "Company Name" field, type in "AGL Resources."
4. In the upper right hand corner, type in "U-13-60" in the "Form Type" field.

A list of the U-13-60 filings will be displayed and can be downloaded.

CGC Shared Service Allocations

Period		Balance Per TRA Form 3.03	Balance Per SEC Form U-13-60
Twelve Months Ended December 31, 2004	**(E)**	6,605,177	6,640,259
Twelve Months Ended December 31, 2003	**(A)**	6,391,326	6,391,326
Twelve Months Ended December 31, 2002	**(A)**	6,068,608	6,068,608
Three Months Ended December 31, 2001	**(B)**	1,324,758	1,324,758
Nine Months Ended September 30, 2001	**(C)**	4,162,412	4,162,412

(A) - Agreed to PSC 3.03 Report for December 2003 - "FYTD" and "FYTD LY" columns

(B) - Agreed to PSC 3.03 Report for December 2001 - "FYTD" column

(C) - Reconciliation for the Nine Months Ended 9/30/01:

Amount Per PSC 3.03 Report for September 30, 2001	**(D)**	5,586,964
Less: Amount per PSC 3.03 Report for December 30, 2000 - "FYTD" column"		1,403,799
Balance for Nine Months Ended September 30, 2001 Per PSC 3.30 Reports		4,183,165
Less - amount allocated from AGL Energy Services		20,753
Amount Allocated form AGL Services Company - Nine months Ended September 30, 2001		4,162,412

(D) - This amount was agreed to the "FYTD" column of the PSC 3.03 report. AGL Resources Inc., and therefore Chattanooga Gas Company, had a fiscal year end of September 30 through the year ended September 30, 2001.

(E) - Shared service allocations per 3.03 report 6,605,177
Allocated "Other Income/Expense" not included in ratemaking cost of service 40,634
Unreconciled difference (5,552)
Amount per SEC Form U-13-60 6,640,259

DISCOVERY REQUEST NO. 7:

Identify each person whom you expect to call as an expert witness at any hearing in this docket, and for each such expert witness:

(A) identify the field in which the witness is to be offered as an expert;

Response:

Each witness expected to present expert testimony in this matter on behalf of Chattanooga Gas Company, Inc. submitted pre-filed testimony with the Petition it filed in this matter June 30, 2006. Since the intervenors' rebuttal testimony has not yet been provided, Chattanooga Gas Company is not aware of issues that may be raised and reserves the right to call additional witnesses as necessary. The response to this request will be supplemented as necessary.

(B) provide complete background information, including the expert's current employer as well as his or her educational, professional and employment history, and qualifications within the field in which the witness is expected to testify, and identify all publications written or presentations presented in whole or in part by the witness;

Response:

See pre-filed testimony and exhibits provided with the Petition it filed in this matter June 30, 2006.

(C) provide the grounds (including without limitation any factual basis), for the opinions to which the witness is expected to testify, and provide a summary of the grounds for each such opinion;

Response:

See pre-filed testimony and exhibits provided with the Petition it filed in this matter June 30, 2006.

(D) identify any matter in which the expert has testified (through deposition or otherwise), by specifying the name, docket number and forum of each case, the dates of the prior testimony and the subject of the prior testimony, and identify the transcripts of any such testimony;

Response:

Witness: Mr. Steve Lindsey

Please see pre-filed testimony filed with the Petition in this proceeding filed June 30, 2006.

Testimony given:

Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges and Revised Tariff:
Docket # 04-00034,
Forum: Tennessee Regulatory Authority
Date Filed: 2004/2005
Subject: General overview of CGC's operations;a summary of rate relief requested

Witness: Michael J. Morley

Please see pre-filed testimony and Attachment A to testimony filed with the Petition filed in this proceeding June 30, 2006.

Testimony given:

Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges and Revised Tariff:
Docket # 04-00034,
Forum: Tennessee Regulatory Authority
Date Filed: 2004/2005
Subject: Chattanooga Gas Company's revenue requirements

Atlanta Gas Light Company's 2004/2005 Rate Case
Docket No. 18638-U
Forum: Georgia Public Service Commission
Filed: 2004/2005
Subject: Atlanta Gas Light Company's revenue requirements

Virginia Natural Gas, Inc. - For approval of a performance based rate regulation methodology pursuant to VA Code section 56-235.6
Case No.PUE-2005-00057
Forum:Virginia State Corporation Commission
Filed: 2005/2006
Subject: Virginia Natural Gas Company's revenue requirements

Virginia Natural Gas, Inc. - For investigation of justness and reasonableness of current rates, charges, and terms and conditions of service in compliance with prior Commission Order
Case No.PUE-2005-00062
Forum:Virginia State Corporation Commission
Filed: 2005/2006
Subject: Virginia Natural Gas Company's revenue requirements

Witness: Philip G. Buchanan

Please see pre-filed testimony and Attachment A to testimony filed with the Petition filed in this proceeding June 30, 2006.

Testimony given:

Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges and Revised Tariff:
Docket # 04-00034,
Forum: Tennessee Regulatory Authority

Date: 2004
Subject: Chattanooga Gas Company's revenue under current rates, and rate design

Atlanta Gas Light Company's 2004/2005 Rate Case
Docket No. 18638-U
Forum: Georgia Public Service Commission
Date: 2004/2005
Subject: Atlanta Gas Light Company's revenue under current rates,and rate design.

Earnings Review to Establish Just and Reasonable Rates for Atlanta Gas Light Company
Deposition taken by GPSC Staff
Docket No. 14311-U
Forum: Georgia Public Service Commission
Date: November 7, 2001
Subject: Forecast of Company revenues in the forward-looking test year.

Witness: Richard R. Lonn

Please see pre-filed testimony and Resume filed with the Petition filed in this proceeding June 30, 2006.

Testimony given:

Petition of Chattanooga Gas Company for Approval of Adjustment of Its Rates and Charges and Revised Tariff:
Docket # 04-00034,
Forum: Tennessee Regulatory Authority
Date: 2004
Subject: Pipeline Replacement Program

Cost Allocation Methodology for Lost and Unaccounted for Natural Gas
Docket 15527-U
Forum: Georgia Public Service Commission
Date: 2002

Subject: Cost Allocation Methodology for Lost and Unaccounted for Natural Gas.

AGLC 2004-2007 Joint Capacity Supply Plan
Docket # 18437-U
Forum: Georgia Public Service Commission
Date: 2004
Subject: Engineering design and cost estimating perspective for the plan to purchase and construct facilities in order to replace two existing pipelines under the Company's Pipeline Replacement Program ("PRP") at significant cost savings to customers.

Earnings Review to Establish Just and Reasonable Rate for AGLC/Pipeline
Replacement Stipulation
Docket #: 18638-U/ 8516-U
Forum: Georgia Public Service Commission
Date: 2004
Subject: Engineering design and cost estimating perspective for the plan to purchase and construct facilities in order to replace two existing pipelines under the Company's Pipeline Replacement Program ("PRP") at significant cost savings to customers.

Complaint of AGLC against the City of Buford for unsafe gas operations
Docket #: 187263-U
Forum: Georgia Public Service Commission
Date: 2004
Subject: The basis for the complaint filed by the Company concerning the City of Buford's unreasonably interfering with the Company's gas distribution system in Hall and Gwinnett Counties, Georgia, by expanding and operating a gas distribution system in those counties in a manner that threatens the safety of residents and businesses.

City of Buford Application for Certificate of Public Convenience and Necessity

Docket #: 19219-U
Forum: Georgia Public Service Commission
Date: 2004
Subject: Responding to the testimony of City of Buford, Georgia requesting a CPCN

Application of AGLC to Amend Certificate Boundary
Docket #: 22466-U
Forum: Georgia Public Service Commission
Date: 2006
Subject: described why AGLC requested an amendment to Distribution Certificate of Public Convenience and Necessity No. 119 to serve the entire Mundy Mill Housing Development ("Mundy Mill") in Hall County, Georgia and to describe the facilities that will used to serve the new development.

CITY OF MONROE, Application for Certificate of Public Convenience and Necessity/ Complaint by AGLC against CITY OF MONROE for Constructing Natural Gas Distribution System in Oconee County, GA without Certification from Commission and Interfering with AGLC's Gas Distribution System
Docket #: 22787-U/ 22850-U
Forum: Georgia Public Service Commission
Date: 2006
Subject: Support for the Company's Motion in response to the Notice of Hearing and Procedural and Scheduling Order issued by the Hearing Officer in Dockets # 22787-U and 22850-U, provide response to the "Matters at Issue" listed in the Procedural Order, and address the City of Monroe's belated request for a certificate.

Witness: David A. Heintz

Please see pre-filed testimony and Appendix A to testimony filed with the Petition filed in this proceeding filed June 30, 2006.

Testimony given:

Texas Eastern Transmission Corp.
Docket/Case No. CP81-237 (1981)
Forum: Federal Energy Regulatory Commission (FERC)
Date: 1981
Subject: Rate Design

Panhandle Eastern Pipeline Company
Docket/Case No.RP82-58
Forum: Federal Energy Regulatory Commission (FERC)
Date: 1982
Subject: Volume Adjustments, Cost Allocation, Rate Design

Empire State Pipeline
Docket/Case No.88-T-132
Forum: New York Pubic Service Commission
Filed: 1989
Subject: Cost of by-pass

Boston Gas Company
Docket/Case No.D.P.U. 96-50
Forum: Massachusetts Department of Public Utilities
Date: 1996
Subject: Weather normalization, revenue adjustments, rate design, tariff changes and transportation pricing

Peoples Natural Gas Company
Docket/Case No.R-00994600
Forum: Pennsylvania Public Service Commission
Date: 1999
Subject: Tariff terms and conditions

South Jersey Gas
Docket/Case No.GX99030121 & GO99030125
Forum: New Jersey Board of Public Utilities
Date: 1999
Subject: Rate unbundling

New England Gas Company
Docket/Case No.3401
Forum: Rhode Island Public Utilities Commission
Date: 2001
Subject: Tariff and rate consolidation, weather normalization, revenue and volume adjustments, allocated cost of service, rate design

Arkansas Oklahoma Gas Corporation
Docket/Case No.05-006-U
Forum: Arkansas Public Service Commission
Date: 2005
Subject: Allocated cost of service and rate design

Dr. Roger A. Morin

Please refer to Exhibit No. RAM-1 to Pre-filed Testimony of Dr. Roger Morin filed with the Petition in this proceeding filed June 30, 2006 for other proceedings in which Dr. Morin has testified.

Mr. Daniel J. Nikolich

Please see pre-filed testimony and Attachment A to Mr. Nikolich's testimony filed with the Petition in this proceeding filed June 30, 2006.

Petition for approval of tariff modification to implement pilot flat rate billing (FRB) program for residential customers in Miami Division and for variance from or waiver of Rules 25-7.084 and 25-7.085, F.A.C., by City Gas Company of Florida
Docket/Case No.021065-GU
Forum: Florida Public Service Commission
Date: 2003
Subject: Rate design

Application for Rate Increase by City Gas Company of Florida.
Docket/Case No.030569-GU
Forum: Florida Public Service Commission
Date: 2004
Subject: Cost-of –Service allocations and Rate Design

In The Matter Of The Petition Of Nui Utilities, Inc. D/B/A Elizabethtown Gas Company For Approval Of Increased Base Tariff Rates And Charges For Gas Service and Other Tariff Revisions
Docket/Case No.GR02040245
Forum: State of New Jersey Board of Public Utilities
Date: 2002
Subject: Cost-of –Service allocations and Rate Design

Application of NUI Valley Cities Gas for Approval of a Restructuring Plan
Docket/Case No.R-00994946
Forum: Pennsylvania Public Utility Commission
Date: 2000
Subject: Rate Design, operational and economic studies and analysis.

Pennsylvania Public Utility Commission the Office of Consumer Advocate v. NUI Valley Cities Gas
Docket/Case No.R-00005810 and R-00005810C0001
Forum: Pennsylvania Public Utility Commission
Date: 2001
Subject: Customer Assistance Rate and Customer Education Rider

Application of NUI North Carolina Gas for Approval of Tariff Revisions to Implement Third Party Supplier Provisions and Request for Interim Relief
Docket/Case No.G-3, Sub 235
Forum: North Carolina Public Utilities Commission
Date: 2001
Subject: Customer Assistance Rate and Customer Education Rider

(E) identify the terms of the retention or engagement of each expert including but not limited to the terms of any retention or engagement letters or agreements relating to his/her engagement, testimony, and opinions as well as the compensation to be paid for the testimony and opinions;

Response:

See attached engagement letters contract for services between CGC and Concentric Energy Advisors (employer of Dave Heintz) and Dr. Roger Morin. These agreements are marked confidential and filed under seal under the protective order issued in this docket. All other expert witnesses who filed direct testimony are internal AGL employees.

(F) identify all documents or things relied upon, or prepared by any expert witness, which are related to the witness(es) expected testimony in this case, whether or not such documents are supportive of such testimony, including without limitation all documents or things provided to that expert for review in connection with testimony and opinions; and

Response:

As noted by the CAPD in its August 23, 2006 "Response to Discovery Objections" and further discussed by the parties at the status conference on that same day, the CAPD agreed to modify this request so that it requires CGC to "identify all documents relied upon or prepared by any expert witness that are related to the witness' testimony." CGC has modified this request accordingly.

To the best of its knowledge, the Company has already identified or will identify all such documents or things in its pre-filed testimony and exhibits filed June 30, 2006, its responses to the minimum filing guidelines, and its responses to the CAPD's, Staff's and CMA's discovery requests. To the extent CGC identifies additional documents or things or additional issues arise, CGC will supplement the appropriate filing or response prior to the hearing on the merits and/or include such information in its pre-filed rebuttal testimony.

(G) identify any exhibits to be used as a summary of or support for the testimony or opinions provided by the expert.

Response:

See exhibits provided with the Company's pre-filed testimony on June 30.2006. In addition, depending on the issues raised in the intervenors' pre-filed testimony, the Company may file rebuttal testimony, which may contain additional exhibits.

DISCOVERY REQUEST NO. 8:

Provide all material relied upon or produced by any witness for Chattanooga Gas or any expert or consultant retained by Chattanooga Gas to testify or to provide information from which another expert will testify concerning this case, including all work papers, reference sources, financial information, discovery responses, e-mails and other materials. Please produce working Microsoft Excel files for all work papers and exhibits.

Response:

As noted by the CAPD in its August 23, 2006 "Response to Discovery Objections" and further discussed by the parties at the status conference on that same day, the CAPD agreed to modify this request so that it requires CGC to produce the documents "relied upon or produced by any witness." CGC has modified this request accordingly.

To the best of its knowledge, the Company has already produced or will produce all such documents in its pre-filed testimony and exhibits filed June 30, 2006, its responses to the minimum filing guidelines, and its responses to the CAPD's, Staff's and CMA's discovery requests. To the extent CGC identifies additional documents or additional issues arise, CGC will supplement the appropriate filing or response prior to the hearing on the merits and/or include such information in its pre-filed rebuttal testimony. In addition, CGC provided its testimony and exhibits on CD to the Staff and CAPD on the same day it filed it Petition and is also providing them on CD in response to TRA No. 1. To the best of its knowledge all workpapers have been provided in excel format in response to the various minimum filing guidelines and discovery requests.

DISCOVERY REQUEST NO. 9:

Produce a copy of all articles, journals, books or speeches written by or co-written by any of Chattanooga Gas expert witnesses, whether published or not.

Response:

As noted by the CAPD in its August 23, 2006 "Response to Discovery Objections" and further discussed by the parties at the status conference on that same day, the CAPD agreed to modify this request so that it requires CGC to produce "a list of the articles, books, etc. that its witnesses have published." CGC will then provide specific requests made by the CAPD "if its witnesses maintain copies under their possession, custody, or control."

The only current expert witness with published articles, journals, books or speeches is Dr. Roger Morin. Please refer to Exhibit RAM-1 for a list of the above referenced published documents.

DISCOVERY REQUEST NO. 10:

Provide the information for Plant in Service and Accumulated Depreciation by account by Chattanooga Gas Company in the following format as of June 30, 2006:

(1)	(2)	(3)	(4)	(5)	(6)
	Account	**Plant in Service**	**Depreciation**	**Accumulated**	**Net**
Acct #	**Description**	**Balance**	**Rate**	**Depreciation**	**Book Value**

Response:

Please see attached CGC Schedule 10-1, which provides the salvage Plant in Service and Accumulated Depreciation by account for Chattanooga Gas Company in the requested format as of June 30, 2006. The depreciation rates provided by plant account represent the most recent rates approved by the Tennessee Regulatory Authority for use by CGC in the calculation of its depreciation expense.

Chattanooga Gas Company
Docket No. 06-00175
CADP -1
Question 10
Schedule 10-1

(1) Account No.	(2) Acct Description	(3) Plant in Service Bal	(4) Deprecitation Rate	(5) Accum. Depretiation	(6) Net Book Value
300100	Organizational Expense	46,201	0.00%	-	46,201
300200	Franchise & Consents	2,028	0.00%	-	2,028
331040	Land	553,383	0.00%	-	553,383
331150	Land Rights	-	2.67%	-	-
331150	Structures & Improvements	11,704,939	2.67%	1,097,808	12,802,747
331250	Gas Holders - LNG	4,515,240	2.67%	4,342,955	8,858,195
331350	Purification Equipment	551,128	2.67%	333,837	(3,791,827)
331450	Liquification Equipment	2,479,046	2.67%	1,475,840	2,145,209
331550	Vaporizing Equiptment	2,387,568	2.67%	1,071,155	911,729
331650	Compressor Equipment	37,726	2.67%	-	37,726
331750	Measuring Equipment	95,050	2.67%	83,318	11,733
331950	Other Equipment	865,245	2.67%	716,536	148,709
351030	Land	35,553	3.37%	-	35,553
351050	Land Rights	386,478	3.37%	87,593	298,885
351100	Structures & Equipment	18,271	3.37%	10,989	7,283
351200	Mains	77,571,682	3.37%	38,722,702	38,848,981
351300	Compressor Station Equipment	1,613,696	3.37%	1,348,070	265,627
351330	Measuring & Reg. Station Equip - General	212,328	3.37%	51,824	160,504
351350	Measuring & Reg. Station Equip - City Gate	1,083,189	3.37%	458,831	624,358
351400	Services	49,633,155	3.37%	19,579,204	30,053,951
351500	Meters	6,749,064	3.37%	3,481,156	3,267,908
351550	ERT's	-	3.37%	37,853	(37,853)
351570	Metreteks	133	3.37%	21	112
351600	Meter Installations	2,951,240	3.37%	891,762	2,059,478
351700	House Regulators	2,971,492	3.37%	1,236,903	1,734,589
351800	House Regulator Installations	168,944	3.37%	62,543	106,401
351850	Industrial Meas & Reg Station Equipmnt	220,719	3.37%	109,283	111,436
351900	Other Distribution Equipment	141,330	3.37%	48,764	92,566
351950	Other Property on Customer's Premises	19,246	3.37%	9,153	10,092
361030	Land	-	7.34%	143	(143)
361100	Structures & Improvements	91,435	7.34%	11,055	80,380
361200	Office Furniture	14,405	7.34%	4,063	10,342
361250	Data Processing Equipment	1,506,614	7.34%	1,023,965	482,649
361300	Transportation Equipment	378,079	7.34%	456,725	(78,647)
361400	Stores Equipment	71,130	7.34%	93,456	(22,326)
361500	Tools, Shop & Garage Equipment	359,435	7.34%	278,814	80,621
361600	Laboratory Equipment	21,879	7.34%	27,818	(5,939)
361700	Power-Operated Equipment	48,044	7.34%	84,222	(36,178)
361800	Communication Equipment	-	7.34%	(9,785)	9,785
361900	Miscellaneous Equipment	11,511	7.34%	13,885	(2,374)
		169,516,606		77,242,460	99,883,872

DISCOVERY REQUEST NO. 12:

Provide the actual FAS 87 pension expense amount by month charged to Tennessee operations from January 2003 through June 30, 2006. Also, provide the forecasted FAS 87 pension expense amount included in the Company's filing for the twelve months ended December 31, 2007.

Response:

Please refer to attached schedule for FAS 87 expense from January 2003 – June 2006. For pension expense included in the Company's filing for the twelve months ended December 31, 2007, please refer to the Company's response to TRA FG No. 25, Schedule 25 – 5. As discussed in that response, the Company has calculated pension expense for rate making purposes based on the estimated contributions to the plan for 2007 and not FAS 87 expense. This is consistent with previous CGC rate cases, most recently, Docket No. 04-00034 in 2004.

Chattanooga Gas Company
FAS 87 Pension Costs
Janaury 2003 - June 2006

	CGC	AGSC	AGSC Percent Costs Allocated to CGC	Pension Costs Allocated to CGC	Total Pension Costs Charged
Jan-03	(60,750)	237,800	4.84%	11,510	(49,240)
Feb-03	(60,750)	237,800	4.84%	11,510	(49,240)
Mar-03	(60,750)	237,800	4.84%	11,510	(49,240)
Apr-03	(47,850)	(409,133)	4.84%	(19,802)	(67,652)
May-03	(57,525)	76,067	4.84%	3,682	(53,843)
Jun-03	(57,525)	76,067	4.84%	3,682	(53,843)
Jul-03	(11,733)	(48,950)	4.84%	(2,369)	(14,103)
Aug-03	(50,983)	135,817	4.84%	6,574	(44,410)
Sep-03	(50,983)	67,908	4.84%	3,287	(47,697)
Oct-03	(50,983)	67,908	4.84%	3,287	(47,697)
Nov-03	(50,983)	67,908	4.84%	3,287	(47,697)
Dec-03	139,717	(192)	4.84%	(9)	139,707
Jan-04	(15,217)	94,942	4.19%	3,978	(11,239)
Feb-04	(27,617)	64,525	4.19%	2,704	(24,913)
Mar-04	(20,867)	48,333	4.19%	2,025	(18,842)
Apr-04	(21,233)	69,267	4.19%	2,902	(18,331)
May-04	(21,233)	69,267	4.19%	2,902	(18,331)
Jun-04	(21,233)	69,267	4.19%	2,902	(18,331)
Jul-04	(34,144)	137,164	4.19%	5,747	(28,397)
Aug-04	(34,144)	137,164	4.19%	5,747	(28,397)
Sep-04	(34,144)	137,164	4.19%	5,747	(28,397)
Oct-04	(34,144)	137,164	4.19%	5,747	(28,397)
Nov-04	(34,144)	137,164	4.19%	5,747	(28,397)
Dec-04	(34,144)	104,973	4.19%	4,398	(29,745)
Jan-05	(20,921)	113,904	3.53%	4,021	(16,900)
Feb-05	(20,921)	113,904	3.53%	4,021	(16,900)
Mar-05	(20,921)	113,904	3.53%	4,021	(16,900)
Apr-05	(26,374)	156,852	3.53%	5,537	(20,837)
May-05	(26,374)	156,852	3.53%	5,537	(20,837)
Jun-05	(26,374)	156,852	3.53%	5,537	(20,837)
Jul-05	(26,374)	156,852	3.53%	5,537	(20,837)
Aug-05	(94,087)	156,852	3.53%	5,537	(88,550)
Sep-05	(32,793)	392,609	3.53%	13,859	(18,934)
Oct-05	(32,793)	168,731	3.53%	5,956	(26,837)
Nov-05	(32,793)	168,731	3.53%	5,956	(26,837)
Dec-05	(32,793)	168,731	3.53%	5,956	(26,837)
Jan-06	(29,039)	180,199	3.25%	5,856	(23,183)
Feb-06	(29,039)	180,199	3.25%	5,856	(23,183)
Mar-06	(29,039)	180,199	3.25%	5,856	(23,183)
Apr-06	(29,039)	180,199	3.25%	5,856	(23,183)
May-06	(29,039)	180,199	3.25%	5,856	(23,183)
Jun-06	(29,039)	180,199	3.25%	5,856	(23,183)

Revision Date:
August 30, 06
05:32 PM

DISCOVERY REQUEST NO. 13:

Provide the actual and forecasted Incentive Plans and amounts by plan by account by month charged to Tennessee operations from January 2003 through June 30, 2006 and the amount by Incentive Plan included in the Company's filing for the twelve months ended December 31, 2007.

Response:

Please refer to attached schedule for the requested information for January 2003 – June 2006. Refer to the Company's response to TRA FG No. 51 for the amounts included in the Company's filing for the twelve months ended December 31, 2007.

Officer Incentive Plan (OIP)

	Period												
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
2003	-	-	-	-	-	-	-	-	69,480	15,462	14,757	18,204	117,903
2004	14,866	14,866	23,942	15,284	14,776	16,934	14,758	5,254	147,386	8,698	8,671	68,468	353,902
2005	4,264	4,599	24,812	10,560	11,543	26,316	12,229	9,923	8,248	13,062	11,194	11,316	148,065
2006	6,930	10,565	27,262	9,910	9,691	24,591							88,949

Note - Above amounts represent costs associated with the OIP that were allocated to CGC. These costs were not separately tracked on a monthly basis until September 2003.

Long-Term Incentive Plan (LTIP)

March 2006	3214
June 2006	2864

Note - Refer to the Company's response to TRA FG 51 for an explanation of the accounting for the LTIP prior to 2006.

Annual Incentive Plan (AIP)

	Period							
Year	**3**	**5**	**6**	**7**	**9**	**10**	**12**	**Total**
2003	204,220	(78,706)	38,184			19,878	139,820	323,396
2004	93,740		47,991	3,151	53,503	14,670	76,273	289,329
2006	33,344		14,290					47,634
2005	96,165		15,106		27,788		204,007	343,065

DISCOVERY REQUEST NO. 14:

Provide all the work papers and documentation in the calculation of all amounts shown on all Schedules and Exhibits MJM-1 through MJM 5. Include in your response, where identifiable, all amounts by FERC account.

Response:

Due to the voluminous nature of this request, the Company's response is being provided on the CD, which is marked confidential and provided under seal under the protective order issued in this docket. Also, refer to the following TRA minimum filing guidelines previously provided:

- TRA FG Item No. 25 filed on June 30, 2006 and addendum filed on July 14, 2006
- TRA FG Item No. 69
- TRA FG Item No. 81
- TRA FG Item No. 71

DISCOVERY REQUEST NO. 15:

Reconcile the amount on Exhibit MJM-1, Schedule 1, Line 7, Column 1 to the grand total amount shown in the company's response in TRA FG-Item No. 42 Attachment B 1 of 1. Provide a detailed documentation and explanation in your response for the difference.

Response:

The information included in Attachment B of TRA FG Item No. 42 is based on the information included in the class cost of service study, which is supported by the direct testimony and exhibits of Dave Heintz. The reason for the difference between the amounts in Attachment B and Exhibit MJM-1, Schedule 1, Line 7, column 1 is the classification of the AGSC shared services cost allocations. In the class cost of service study, these costs were mapped to FERC accounts, including depreciation and taxes other than income. Therefore, the amounts included in attachment B do not include AGSC shared service allocations mapped to FERC accounts for depreciation and taxes other than income.

The amount included in Exhibit MJM-1, Schedule 1, Line 7, column 1 represents the total AGSC shared service allocations estimated for the attrition period, including costs associated with depreciation and taxes other than income. Reporting the total amount of AGSC shared service allocations as operations and maintenance expense in Exhibit MJM-1, Schedule 1, Line 7, column 1 is consistent with how CGC reports AGSC allocations in its monthly 3.03 reports.

See attached Schedule CAPD 15-1 for a reconciliation between the two amounts.

Chattanooga Gas Company
Docket No. 06-00175
CAPD - 1
Question No. 15
Schedule CAPD 15-1

Description	FERC Acct#			
	403 Total	(a)	263,240.89	
	408.1 Total	(a)	131,604.40	
	840 Total		4,970.79	
	841 Total		40,171.14	
	843.2 Total		62.16	
	843.3 Total		49.01	
	843.4 Total		1,616.35	
	843.5 Total		914.16	
	843.6 Total		3,382.41	
	843.7 Total		2,054.21	
	843.9 Total		8,410.35	
	870 Total		578.11	
	871 Total		-	
	874 Total		11,767.13	
	875 Total		-	
	877 Total		13,927.11	
	878 Total		86.28	
	879 Total		30.33	
	880 Total		8,933.63	
	887 Total		2,705.46	
	888 Total		404.96	
	889 Total		1,535.73	
	891 Total		-	
	892 Total		907.83	
	893 Total		2,971.97	
	894 Total		1,653.07	
	902 Total		18.99	
	903 Total		2,075.62	
	904 Total		-	
	905 Total		2,437.54	
	908 Total		91,406.24	
	909 Total		-	
	912 Total		1.40	
	913 Total		108,819.78	
	916 Total		348.25	
	920 Total		1,467,367.46	
	921 Total		404,702.67	
	922 Total		(188,343.36)	
	923 Total		1,046,274.51	
	924 Total		134,296.39	
	925 Total		58,706.43	
	926 Total		898,122.83	
	928 Total		16.58	
	930.1 Total		125.88	
	930.2 Total		181,579.59	
	931 Total		203,522.70	
	932 Total		315,243.01	
	Grand Total		5,228,700.00	Agrees to Exhibit MJM-2, Schedule 2, Line 11, "Attrition Period"

Amount per Exhibit MJM-1, Schedule 1, Line 7, Column 1	11,711,087	
Amount per Attachment B of TRA FG Item No. 42	11,317,034	
Difference	394,053	
Depreciation Expense and Taxes Other than Income	394,845	Sum of (a) - not included in Attachment B of TRA FG Item No. 42; included in Exhibit MJM-1, Schedule 1, Line 7, Column 1
Remaining Difference - unreconciled, minor amount	(792)	

DISCOVERY REQUEST NO. 16:

Provide a trial balance as of June 30, 2006

Response:

Refer to the Company's response to TRA Staff -1, Question 5.

DISCOVERY REQUEST NO. 17:

Identify each payee by amount for the estimated Rate Case costs amount of $300,000 as described in the direct testimony of Michael Morley, Page 11, Line 19.

Response:

Please refer to TRA FG Item No. 58.

DISCOVERY REQUEST NO. 18:

Provide copies of all ad valorem property tax bills paid for the tax years 2003 through 2005. Include in your response the amount paid, the assessment value, and the tax rate by taxing jurisdiction.

Response:

Please refer to TRA FG Number 60 for copies of the ad valorem property tax bills for the tax years 2003 through 2005. See attached CGC Schedule 18-1, which provides the amounts paid, assessment values, and tax rates by tax jurisdiction.

Chattanooga Gas Company
Docket No. 06-00175
CAPD - 1
Question 18

Tax Year	Billing Tax District	Tax Location	Distribution Amount	Localized Assessment Amount	Assessment Ratio	Tax Rate	Tax Amount
2003	BRADLEY CO	BRADLEY CO	19,191,254	4,118,279	4.66	2.2422	92,340.05
2003	CITY OF CLEVELAND	CITY OF CLEVELAND	13,340,263	2,867,067	4.65	1.65	47,307.00
2003	TOWN OF LOOKOUT MTN	TOWN OF LOOKOUT MTN	1,806,531	341,466	5.29	2.2	7,512.25
2003	City of Chattanooga	City of Chattanooga	62,441,847	20,972,881	2.98	2.516	527,677.69
2003	Town of Signal Mtn	Town of Signal Mtn	4,603,739	870,315	5.29	1.65	14,360.20
2003	Hamilton Co	CO OSAP City of Chattanooga	62,441,847	20,972,881	2.98	3.061	641,979.89
2003	Hamilton Co	CO OSAP Collegedale	1,243,205	234,988	5.29	3.061	7,192.98
2003	Hamilton Co	CO OSAP East Ridge	5,749,817	1,088,950	5.28	3.061	33,332.76
2003	Hamilton Co	CO OSAP Hamilton Co South	29,739,763	5,638,041	5.27	3.061	172,580.44
2003	Hamilton Co	CO OSAP LAKESITE	349,650	66,090	5.29	3.061	2,023.01
2003	Hamilton Co	CO OSAP LOOKOUT MOUNTAIN	1,806,531	341,466	5.29	3.061	10,452.27
2003	Hamilton Co	CO OSAP RED BANK	5,050,516	954,636	5.29	3.061	29,221.41
2003	Hamilton Co	CO OSAP Ridgeside	194,251	36,717	5.29	3.061	1,123.91
2003	Hamilton Co	CO OSAP Town of Signal Mtn	4,603,739	870,315	5.29	3.061	26,640.34
2003	Hamilton Co	Co OSAP Walden	1,359,754	257,018	5.29	3.061	7,867.32
2003	Hamilton Co	Collegedale OSAP	1,243,205	234,988	5.29	1.0786	2,534.58
2003	Hamilton Co	East Ridge OSAP	5,749,817	1,088,950	5.28	1.25	13,611.88
2003	Hamilton Co	LAKESITE OSAP	349,650	66,090	5.29	0.339	224.05
2003	Hamilton Co	RED BANK OSAP	5,050,516	954,636	5.29	1.22	11,646.56
2003	Hamilton Co	Ridgeside OSAP	194,251	36,717	5.29	1.93	708.64
2003	Hamilton Co	Walden OSAP	1,359,754	257,018	5.29	0.58	1,490.70
	Total		227,869,900	62,269,509			1,651,828

Chattanooga Gas Company
Docket No. 06-00175
CAPD - 1
Question 18

Tax Year	Billing Tax District	Tax Location	Distribution Amount	Localized Assessment Amount	Assessment Ratio	Tax Rate	Tax Amount
2004	BRADLEY CO	BRADLEY CO	21,133,188	5,092,625	4.15	2.2433	114,241.90
2004	TOWN OF LOOKOUT MTN	TOWN OF LOOKOUT MTN	1,836,245	429,221	4.28	2.7	11,588.97
2004	CITY OF CLEVELAND	CITY OF CLEVELAND	14,690,143	3,432,593	4.28	1.65	56,637.78
2004	City of Chattanooga	City of Chattanooga	63,468,895	23,704,043	2.68	2.516	596,393.72
2004	Town of Signal Mtn	Town of Signal Mtn	4,679,461	1,093,821	4.28	1.65	18,048.05
2004	Hamilton Co	CO OSAP City of Chattanooga	63,468,895	23,704,043	2.68	3.061	725,580.76
2004	Hamilton Co	CO OSAP Collegedale	1,263,652	295,378	4.28	3.061	9,041.52
2004	Hamilton Co	CO OSAP East Ridge	5,844,391	1,366,122	4.28	3.061	41,816.99
2004	Hamilton Co	CO OSAP Hamilton Co South	30,228,924	7,083,750	4.27	3.061	216,833.59
2004	Hamilton Co	CO OSAP LAKESITE	355,401	83,074	4.28	3.061	2,542.90
2004	Hamilton Co	CO OSAP LOOKOUT MOUNTAIN	1,836,245	429,221	4.28	3.061	13,138.45
2004	Hamilton Co	CO OSAP RED BANK	5,133,586	1,199,972	4.28	3.061	36,731.14
2004	Hamilton Co	CO OSAP Ridgeside	197,445	46,152	4.28	3.061	1,412.71
2004	Hamilton Co	CO OSAP Town of Signal Mtn	4,679,461	1,093,821	4.28	3.061	33,481.86
2004	Hamilton Co	Co OSAP Walden	1,382,120	323,069	4.28	3.061	9,889.14
2004	Hamilton Co	Collegedale OSAP	1,263,652	295,378	4.28	1.05	3,101.47
2004	Hamilton Co	East Ridge OSAP	5,844,391	1,366,122	4.28	1.25	17,076.53
2004	Hamilton Co	LAKESITE OSAP	355,401	83,074	4.28	0.339	281.62
2004	Hamilton Co	RED BANK OSAP	5,133,586	1,199,972	4.28	1.22	14,639.66
2004	Hamilton Co	Ridgeside OSAP	197,445	46,152	4.28	1.93	890.73
2004	Hamilton Co	Walden OSAP	1,382,120	323,069	4.28	0.58	1,873.80
	Total		234,374,647	72,690,672			1,925,243

Chattanooga Gas Company
Docket No. 06-00175
CAPD - 1
Question 18

Tax Year	Billing Tax District	Tax Location	Distribution Amount	Localized Assessment Amount	Assessment Ratio	Tax Rate	Tax Amount
2005	TOWN OF LOOKOUT MTN	TOWN OF LOOKOUT MTN	1,835,232	524,890	3.50	2.0136	20,566.04
2005	BRADLEY CO	BRADLEY CO	21,170,249	6,090,601	3.48	2.0802	126,695.77
2005	CITY OF CLEVELAND	CITY OF CLEVELAND	14,715,905	4,208,860	3.50	1.65	69,446.00
2005	City of Chattanooga	City of Chattanooga	63,433,907	27,751,225	2.29	2.202	611,081.97
2005	Town of Signal Mtn	Town of Signal Mtn	4,676,880	1,337,623	3.50	1.425	19,061.13
2005	Hamilton Co	CO OSAP City of Chattanooga	63,433,907	27,751,225	2.29	2.894	803,120.00
2005	Hamilton Co	CO OSAP Collegedale	1,262,956	361,215	3.50	2.894	10,454.00
2005	Hamilton Co	CO OSAP East Ridge	5,841,169	1,670,619	3.50	2.894	48,348.00
2005	Hamilton Co	CO OSAP Hamilton Co South	30,212,260	8,656,363	3.49	2.894	250,515.00
2005	Hamilton Co	CO OSAP LAKESITE	355,205	101,591	3.50	2.894	2,940.00
2005	Hamilton Co	CO OSAP LOOKOUT MOUNTAIN	1,835,232	524,890	3.50	2.894	15,190.00
2005	Hamilton Co	CO OSAP RED BANK	5,130,756	1,467,435	3.50	2.894	42,468.00
2005	Hamilton Co	CO OSAP Ridgeside	197,336	56,440	3.50	2.894	1,633.00
2005	Hamilton Co	CO OSAP Town of Signal Mtn	4,676,880	1,337,623	3.50	2.894	38,711.00
2005	Hamilton Co	Co OSAP Walden	1,381,357	395,079	3.50	2.894	11,434.00
2005	Hamilton Co	Collegedale OSAP	1,262,956	361,215	3.50	0.952	3,439.00
2005	Hamilton Co	East Ridge OSAP	5,841,169	1,670,619	3.50	1.077	17,993.00
2005	Hamilton Co	LAKESITE OSAP	355,205	101,591	3.50	0.29	295.00
2005	Hamilton Co	RED BANK OSAP	5,130,756	1,467,435	3.50	1.26	18,490.00
2005	Hamilton Co	Ridgeside OSAP	197,336	56,440	3.50	1.501	847.00
2005	Hamilton Co	Walden OSAP	1,381,357	395,079	3.50	0.5	1,975.00
	Total		234,328,010	86,288,058			2,114,703

DISCOVERY REQUEST NO. 20:

Provide the total gross ad valorem assessment amounts and the equalized ad valorem assessment amounts for the years 2002-2006.

Response:

The total gross ad valorem assessment amounts are as follows:

2002 – $43,469,000
2003 – $43,537,000
2004 – $45,889,000
2005 – $49,882,000
2006 – $54,854,000

The equalized ad valorem assessment amounts are as follows:

2002 – $40,934,288
2003 – $34,579,381
2004 – $40,717,227
2005 – $48,413,081
2006 – Not Yet Available

DISCOVERY REQUEST NO. 22:

Provide the total expenses subject to allocation by Atlanta Gas Light Services Company (Affiliated Utility Service Company) by FERC account for the years 2003-2007.

Response:

Please refer to the following schedules:

- Schedule 22-1 – allocable costs for 2005
- Schedule 22-2 – allocable costs for 2004
- Schedule 22-3 – allocable costs for 2003

The above schedules include allocable costs that, when allocated, are included in CGC's ratemaking cost of service. Costs such as income taxes and other income/expense not included in CGC's ratemaking cost of service are not included in the above schedule.

The Company does not have AGSC allocable costs by FERC account for 2006 and 2007.

Line#		FERC Acct#	12/31/2005 GL29
128	Other storage - opn supv & eng	840	$ 179,861.61
129	Other stg - opn labor and exps	841	$ 1,453,541.47
137	Mtc structures & improvements	843.2	$ 2,249.14
138	Mtc gas holders	843.3	$ 1,773.21
139	Mtc of purification equipment	843.4	$ 58,485.67
140	Mtc liquefaction equipment	843.5	$ 33,077.63
141	Mtc vaporizing equipment	843.6	$ 122,388.33
142	Mtc compressor equipment	843.7	$ 74,328.91
144	Mtc other equipment	843.9	$ 304,317.88
204	Operation supvn & engineering	870	$ 20,918.29
205	Distribution load dispatching	871	$ -
208	Mains and services exps	874	$ 425,778.72
211	Meas & reg stn - city gate cks	877	$ 503,934.57
212	Meter & house regulator exp	878	$ 3,121.92
213	Customer installation exps	879	$ 1,097.28
214	Other expenses	880	$ 323,251.89
220	Maintenance of mains	887	$ 97,893.59
221	Mtce compresson stn equipment	888	$ 14,652.86
222	Mtc measuring & reg stn equip	889	$ 55,568.43
225	Maintenance of services	892	$ 32,848.82
226	Mtc meters & house regulators	893	$ 107,536.96
227	Maintenance other equipment	894	$ 59,814.16
233	Meter reading	902	$ 687.21
234	Customer records & collections	903	$ 75,103.64
236	Misc customer accts expense	905	$ 88,199.14
241	Customer assistance	908	$ 3,307,418.24
248	Demonstrating and selling exps	912	$ 50.83
249	Advertising expenses	913	$ 3,937,504.80
250	Miscellaneous sales expenses	916	$ 12,601.03
254	A&G salaries	920	$ 53,094,819.88
255	Office supplies and expenses	921	$ 14,643,649.74
256	Administrative exps transferre	922	$ (6,814,964.22)
257	Outside services employed	923	$ 37,858,108.74
258	Property Insurance	924	$ 4,859,343.75
259	Injuries and damages	925	$ 2,124,217.11
260	Employee pensions and benefits	926	$ 32,497,429.09
261	Franchise requirements		$ 60.00
262	Regulatory commission expense	928	$ 600.00
264	General advertising expense	930.1	$ 4,554.92
265	Miscellaneous general expenses	930.2	$ 6,501,398.97
266	Rents	931	$ 7,364,209.45
269	Maintenance of general plant	932	$ 11,406,666.21
	Total		$ 174,838,099.87
	Depreciation		9,525,035.83
	Taxes Other than Income Tax		4,761,937.38
			$ 189,125,073.08
	Cost of Capital allocated directly assigned to FERC account# 427	427	3,423,542.07
	Total AGSC Charges - Test Period		192,548,615.15

Sum of Amount	Year
FERC Account	**2004**
403	9,137,853
404.3	171,222
408.1	3,742,283
427	2,268,893
840	163,693
841	1,209,434
843.2	38,836
843.3	211
843.4	126,410
843.5	283,757
843.6	73,810
843.7	90,432
843.9	300,197
850	152
870	58,070
871	5,120
874	513,070
877	544,101
878	693
879	67
880	210,050
887	68,960
888	1,913
889	27,763
892	39,095
893	114,708
894	51,509
903	86,916
905	117,332
907	88
908	1,168,443
909	(82)
912	25,957
913	1,470,669
916	36,194
920	44,117,815
921	11,023,474
922	(7,340,431)
923	24,554,795
924	4,150,592
925	1,721,463
926	30,030,823
930.2	3,920,682
931	7,160,722
932	10,175,857
Grand Total	151,663,609

FERC Account	2003
403 Total	9,429,102
404.3 Total	(1,768)
408.1 Total	2,437,393
426.3 Total	45,557
427 Total	2,374,354
841 Total	156,219
842.3 Total	915
843 Total	1,191,682
843.2 Total	1,587
843.3 Total	8,049
843 Total	23,518
843.4 Total	38,974
843.5 Total	154,761
843.6 Total	122,501
843.7 Total	182,311
843.9 Total	339,346
870 Total	1,336,626
871 Total	1,011,166
874 Total	916,195
875 Total	459,853
877 Total	680,630
878 Total	48,870
879 Total	1,780
880 Total	929,004
887 Total	62,985
889 Total	71,968
892 Total	38,439
893 Total	210,202
902 Total	6,168
903 Total	184,141
904 Total	1,500
905 Total	199,798
907 Total	429
908 Total	6,105,283
912 Total	15,021
913 Total	938,486
916 Total	1,206,552
920 Total	33,922,104
921 Total	9,937,031
922 Total	(8,241,249)
923 Total	16,745,157
924 Total	4,141,193
925 Total	1,754,116
926 Total	31,294,130
930.2 Total	4,187,815
930 Total	1,822,875
930.2 Total	(373,208)
931 Total	10,554,255
932 Total	7,569,355
999 Total	404
Grand Total	144,243,575

DISCOVERY REQUEST NO. 23:

According to the Direct Testimony of Dr. Roger A. Morin, page 7, lines 5-8, A[A] company will be unable to attract the capital it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. Please explain all facts and provide copies of all documents that are relevant to the determination of whether the Company has been unable to attract the capital it needs to meet its service demands and to maintain financial integrity since the implementation of the rates put into effect as a result of Docket No. 04-00034.

Response:

CGC does not raise capital on its own, as all its new capital is raised via the parent company. In view of its very small size, it is doubtful if CGC could obtain capital under the same terms and conditions as AGL Resources. It is thus impossible to determine to what extent CGC has been unable to attract capital since the last rate order.

One can say, however, that under its own steam, CGC would have very limited access to capital markets and would be forced to borrow through personal guarantees and/or private placements. The company is relatively unknown, and there would be little institutional interest. In comparison to larger market-cap companies, CGC's profile in the market would be very low. CGC does not, and would not, have its securities rated by bond rating agencies and/or investment houses. Unlike the vast majority of energy utilities, CGC is too small to have rated debt or publicly-held stock, and could not issue debt on a stand alone basis. Any debt issue must be guaranteed by a parent corporation or must be guaranteed by shareholders at the personal level. Access to the equity market by CGC would be virtually non-existent.

Besides, the issue is not so much whether CGC will be able to attract capital but at what cost and under what terms. The latter are likely to be prohibitive for CGC.

The diversification activities of a diversified parent such as AGL reduce risk through a co-insurance effect stemming from its subsidiary activities. Because the cash flows of

individual operating units are less than perfectly correlated, the probability of default is reduced by their consolidation under one roof. To the extent that this co-insurance effect exists, the cost of debt is impacted directly and favorably. CGC 's ratepayers enjoy the benefits of AGL's financial strength and lower cost of capital compared to what CGC's financial strength and cost of capital would be on a stand-alone basis. Given its smaller size, CGC would not enjoy the same creditworthiness and financial solidity as AGL as a whole.

DISCOVERY REQUEST NO. 24:

Regarding Mr. Morin's Exhibit RAM-3 testimony please provide in working, machine-readable excel files:

- Copies of the source sheets referenced as "Mergent's (Moody's) Public Utility Manual" and "Ibbotson Associates 2002 Yearbook";
- For each column and each row on each page of the Exhibit, please provide in working, machine-readable excel files the calculations which relate columns 3, 4, and 5 to columns 1 and 2;
- For reach row on each page of the Exhibit, please provide in working, machine-readable excel files the calculations or source data, such as an index, which lead to the values in the column labeled "Stock Total Return, and name or identify the index, such as "S&P 500", for example;
- For each column and each row on each page of the Exhibit, please provide in working, machine-readable excel files the calculations which relate columns 6, 7, 8, and 9 to columns 10 and 11;
- For each row on each page of the Exhibit, name the companies composing the stock index in column 6;
- For each row on each page of the Exhibit, show how the stock index in column 6 is calculated. If there is no data to identify such calculations, then so state.

Response:

See attachments.

MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Governmen Bond Yield -1	20 year Maturity Bond Value -2	Gain/Loss -3	Interest -4	Bond Total Return -5	Moody's Natural Gas Distribution Stock Index -6	Dividend -7	Capital Gain/(Loss) % Growth -8	Yield -9	Stock Total Return -10	Equity Risk Premium -11
1954	2.72%	1,000.00				26.47					
1955	2.95%	965.44	-34.56	27.20	-0.74%	28.10	1.38	6.16%	5.21%	11.37%	12.11%
1956	3.45%	928.19	-71.81	29.50	-4.23%	28.23	1.48	0.46%	5.27%	5.73%	9.96%
1957	3.23%	1,032.23	32.23	34.50	6.67%	25.78	1.49	-8.68%	5.28%	-3.40%	-10.07%
1958	3.82%	918.01	-81.99	32.30	-4.97%	38.71	1.57	50.16%	6.09%	56.25%	61.21%
1959	4.47%	914.65	-85.35	38.20	-4.71%	39.59	1.66	2.27%	4.29%	6.56%	11.28%
1960	3.80%	1,093.27	93.27	44.70	13.80%	48.21	1.84	21.77%	4.65%	26.42%	12.62%
1961	4.15%	952.75	-47.25	38.00	-0.92%	64.96	1.94	34.74%	4.02%	38.77%	39.69%
1962	3.95%	1,027.48	27.48	41.50	6.90%	59.73	2.02	-8.05%	3.11%	-4.94%	-11.84%
1963	4.17%	970.35	-29.65	39.50	0.99%	64.62	2.18	8.19%	3.65%	11.84%	10.85%
1964	4.23%	991.96	-8.04	41.70	3.37%	68.24	2.30	5.60%	3.56%	9.16%	5.80%
1965	4.50%	964.64	-35.36	42.30	0.69%	64.31	2.48	-5.76%	3.63%	-2.12%	-2.82%
1966	4.55%	993.48	-6.52	45.00	3.85%	53.50	2.61	-16.81%	4.06%	-12.75%	-16.60%
1967	5.56%	879.01	-120.99	45.50	-7.55%	50.49	2.74	-5.63%	5.12%	-0.50%	7.04%
1968	5.98%	951.38	-48.62	55.60	0.70%	53.80	2.81	6.56%	5.57%	12.12%	11.42%
1969	6.87%	904.00	-96.00	59.80	-3.62%	43.88	2.93	-18.44%	5.45%	-12.99%	-9.37%
1970	6.48%	1,043.38	43.38	68.70	11.21%	52.33	3.01	19.26%	6.86%	26.12%	14.91%
1971	5.97%	1,059.09	59.09	64.80	12.39%	47.86	3.07	-8.54%	5.87%	-2.68%	-15.06%
1972	5.99%	997.69	-2.31	59.70	5.74%	53.54	3.12	11.87%	6.52%	18.39%	12.65%
1973	7.26%	867.09	-132.91	59.90	-7.30%	43.43	3.28	-18.88%	6.13%	-12.76%	-5.46%
1974	7.60%	965.33	-34.67	72.60	3.79%	29.71	3.34	-31.59%	7.69%	-23.90%	-27.69%
1975	8.05%	955.63	-44.37	76.00	3.16%	38.29	3.48	28.88%	11.71%	40.59%	37.43%
1976	7.21%	1,088.25	88.25	80.50	16.87%	51.80	3.70	35.28%	9.66%	44.95%	28.07%
1977	8.03%	919.03	-80.97	72.10	-0.89%	50.88	3.93	-1.78%	7.59%	5.81%	6.70%
1978	8.98%	912.47	-87.53	80.30	-0.72%	45.97	4.18	-9.65%	8.22%	-1.43%	-0.71%
1979	10.12%	902.99	-97.01	89.80	-0.72%	53.50	4.44	16.38%	9.66%	26.04%	26.76%
1980	11.99%	859.23	-140.77	101.20	-3.96%	56.61	4.68	5.81%	8.75%	14.56%	18.52%
1981	13.34%	906.45	-93.55	119.90	2.63%	53.50	5.12	-5.49%	9.04%	3.55%	0.92%
1982	10.95%	1,192.38	192.38	133.40	32.58%	50.62	5.39	-5.38%	10.07%	4.69%	-27.89%
1983	11.97%	923.12	-76.88	109.50	3.26%	55.79	5.55	10.21%	10.96%	21.18%	17.92%
1984	11.70%	1,020.70	20.70	119.70	14.04%	69.70	5.88	24.93%	10.54%	35.47%	21.43%
1985	9.56%	1,189.27	189.27	117.00	30.63%	76.58	6.22	9.87%	8.92%	18.79%	-11.83%
1986	7.89%	1,166.63	166.63	95.60	26.22%	90.89	5.71	18.69%	7.46%	26.14%	-0.08%
1987	9.20%	881.17	-118.83	78.90	-3.99%	77.25	6.02	-15.01%	6.62%	-8.38%	-4.39%
1988	9.18%	1,001.82	1.82	92.00	9.38%	86.76	6.30	12.31%	8.16%	20.47%	11.08%
1989	8.16%	1,099.75	99.75	91.80	19.16%	117.05	6.58	34.91%	7.58%	42.50%	23.34%
1990	8.44%	973.17	-26.83	81.60	5.48%	108.86	6.84	-7.00%	5.84%	-1.15%	-6.63%
1991	7.30%	1,118.94	118.94	84.40	20.33%	124.32	6.99	14.20%	6.42%	20.62%	0.29%
1992	7.26%	1,004.19	4.19	73.00	7.72%	138.79	7.14	11.64%	5.74%	17.38%	9.66%
1993	6.54%	1,079.70	79.70	72.60	15.23%	154.06	7.30	11.00%	5.26%	16.26%	1.03%
1994	7.99%	856.40	-143.60	65.40	-7.82%	126.96	7.44	-17.59%	4.83%	-12.76%	-4.94%
1995	6.03%	1,225.98	225.98	79.90	30.59%	155.94	7.56	22.83%	5.95%	28.78%	-1.81%
1996	6.73%	923.67	-76.33	60.30	-1.60%	166.64	7.91	6.86%	5.07%	11.93%	13.54%
1997	6.02%	1,081.92	81.92	67.30	14.92%	191.04	8.02	14.64%	4.81%	19.46%	4.53%
1998	5.42%	1,072.71	72.71	60.20	13.29%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.26%
1999	6.82%	848.41	-151.59	54.20	-9.74%	166.84	8.22	-5.87%	4.64%	-1.23%	8.51%
2000	5.58%	1,148.30	148.30	68.20	21.65%	200.68	8.22	20.28%	4.93%	25.21%	3.56%
2001	5.75%	979.95	61.94	51.23	11.87%	209.67	8.22	4.48%	4.10%	8.58%	-3.29%
MEAN					**6.50%**					**12.16%**	**5.66%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields December each year.

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.95	-27.12%	4.95%	-22.17%	-22.28%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.60	-26.70%	5.57%	-21.13%	-30.96%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.32	71.23%	6.27%	77.49%	71.96%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.48	15.36%	4.10%	19.47%	13.43%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.74	-41.73%	4.18%	-37.55%	-37.34%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.50	13.66%	6.19%	19.84%	13.83%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.48	4.72%	5.37%	10.09%	3.41%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.54	-22.98%	5.34%	-17.64%	-25.19%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.44	-39.47%	6.48%	-32.99%	-33.29%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.26	6.25%	9.37%	15.61%	20.18%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.28	47.03%	8.96%	55.98%	53.84%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.31	0.38%	6.24%	6.62%	3.82%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.30	47.65%	6.16%	53.82%	43.63%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.43	5.04%	4.59%	9.63%	9.75%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.56	-21.74%	4.77%	-16.97%	-14.20%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.60	2.34%	6.25%	8.59%	5.21%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.66	16.68%	6.34%	23.02%	16.09%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.76	0.79%	5.76%	6.54%	6.86%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.88	9.87%	6.10%	15.97%	20.65%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.91	11.82%	5.64%	17.46%	16.29%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.01	4.65%	5.31%	9.96%	6.40%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.13	20.07%	5.38%	25.45%	22.40%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.21	3.76%	4.65%	8.41%	9.15%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.32	-0.79%	4.70%	3.91%	8.14%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.43	2.74%	4.96%	7.70%	1.03%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.50	31.95%	4.97%	36.92%	41.89%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.61	-0.90%	3.93%	3.03%	7.74%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.68	16.80%	4.07%	20.88%	7.08%
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.81	29.29%	3.66%	32.95%	33.87%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	2.97	-2.85%	2.99%	0.14%	-6.76%
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.21	6.03%	3.33%	9.36%	8.37%
1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.43	12.93%	3.35%	16.28%	12.92%
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	3.86	-0.59%	3.34%	2.75%	2.06%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.11	-7.72%	3.58%	-4.14%	-7.99%
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.34	-7.36%	4.09%	-3.26%	4.29%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.50	5.96%	4.58%	10.54%	9.84%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.61	-18.67%	4.43%	-14.23%	-10.62%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.70	4.69%	5.55%	10.25%	-0.96%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.77	-3.42%	5.38%	1.96%	-10.42%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.87	-2.28%	5.69%	3.41%	-2.33%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.01	-27.20%	5.99%	-21.21%	-13.90%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.97	35.20%	12.07%	47.27%	44.10%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.18	19.10%	9.31%	28.40%	11.53%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.54	2.87%	8.36%	11.22%	12.11%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.81	-12.38%	8.52%	-3.86%	-3.13%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.22	-5.59%	10.41%	4.82%	5.54%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.58	-3.53%	11.66%	8.14%	12.09%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	6.99	5.11%	12.84%	17.95%	15.32%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.43	22.83%	12.99%	35.82%	3.24%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	7.87	2.52%	11.20%	13.72%	10.46%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.26	11.29%	11.47%	22.75%	8.71%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.61	18.49%	10.74%	29.23%	-1.40%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.89	19.67%	9.36%	29.03%	2.80%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.87	7.11%	9.41%	16.52%	7.14%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.82	21.38%	8.74%	30.12%	10.96%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.79	-3.88%	7.17%	3.30%	-2.18%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	8.95	22.29%	7.60%	29.89%	9.55%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	9.05	-2.06%	6.28%	4.23%	-3.49%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	8.99	4.00%	6.37%	10.37%	-4.86%
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	8.96	-21.27%	6.11%	-15.16%	-7.34%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.33%	4.44%	-19.89%	-10.15%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	979.95	-20.05	55.80	3.57%	214.08	8.56	-5.73%	3.77%	-1.96%	-5.54%
Mean											**5.55%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

Stocks, Bonds, Bills, and Inflation

SBBI

Valuation Edition
2006 Yearbook

ibbotson

Table 2-1

Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes
Summary Statistics of Annual Returns

from 1926 to 2005

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Serial Correlation
Large Company Stocks				
Total Returns	10.4%	12.3%	20.2%	0.03
Income	4.2	4.2	1.5	0.89
Capital Appreciation	5.9	7.8	19.5	0.03
Ibbotson Small Company Stocks				
Total Returns	12.6	17.4	32.9	0.06
Mid-Cap Stocks*				
Total Returns	11.4	14.2	24.7	-0.02
Income	4.1	4.1	1.7	0.89
Capital Appreciation	7.1	9.8	24.1	-0.02
Low-Cap Stocks*				
Total Returns	11.7	15.7	29.5	0.03
Income	3.7	3.7	2.0	0.89
Capital Appreciation	7.9	11.7	28.9	0.03
Micro-Cap Stocks*				
Total Returns	12.7	18.8	39.2	0.08
Income	2.6	2.6	1.8	0.91
Capital Appreciation	10.1	16.1	38.6	0.08
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.5	0.08
Long-Term Government Bonds				
Total Returns	5.5	5.8	9.2	-0.08
Income	5.2	5.2	2.7	0.96
Capital Appreciation	0.1	0.4	8.1	-0.22
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.15
Income	4.7	4.8	2.9	0.96
Capital Appreciation	0.4	0.5	4.4	-0.19
Treasury Bills				
Total Returns	3.7	3.8	3.1	0.91
Inflation	3.0	3.1	4.3	0.65

Total return is equal to the sum of three component returns; income return, capital appreciation return, and reinvestment return.

*Source: Center for Research in Security Prices, University of Chicago. See Chapter 7 for details on decile construction.

Table A-9

Long-Term Government Bonds: Yields

from January 1926 to December 1970

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan-Dec
1926	0.0374	0.0372	0.0371	0.0368	0.0369	0.0368	0.0370	0.0373	0.0372	0.0367	0.0358	0.0354	1926	0.0354
1927	0.0351	0.0347	0.0331	0.0333	0.0327	0.0334	0.0333	0.0329	0.0330	0.0325	0.0320	0.0316	1927	0.0316
1928	0.0321	0.0318	0.0317	0.0319	0.0327	0.0326	0.0344	0.0341	0.0346	0.0336	0.0338	0.0340	1928	0.0340
1929	0.0349	0.0363	0.0377	0.0358	0.0373	0.0367	0.0369	0.0375	0.0375	0.0347	0.0331	0.0340	1929	0.0340
1930	0.0347	0.0339	0.0335	0.0338	0.0329	0.0328	0.0327	0.0328	0.0324	0.0324	0.0322	0.0330	1930	0.0330
1931	0.0343	0.0338	0.0332	0.0327	0.0317	0.0319	0.0325	0.0326	0.0353	0.0385	0.0385	0.0407	1931	0.0407
1932	0.0390	0.0367	0.0370	0.0336	0.0349	0.0347	0.0320	0.0321	0.0319	0.0322	0.0322	0.0315	1932	0.0315
1933	0.0308	0.0325	0.0321	0.0325	0.0308	0.0306	0.0309	0.0308	0.0308	0.0315	0.0327	0.0336	1933	0.0336
1934	0.0321	0.0317	0.0307	0.0300	0.0292	0.0289	0.0288	0.0299	0.0310	0.0300	0.0299	0.0293	1934	0.0293
1935	0.0281	0.0275	0.0274	0.0269	0.0276	0.0270	0.0268	0.0281	0.0282	0.0279	0.0280	0.0276	1935	0.0276
1936	0.0285	0.0281	0.0275	0.0274	0.0273	0.0273	0.0271	0.0264	0.0268	0.0269	0.0257	0.0255	1936	0.0255
1937	0.0258	0.0253	0.0285	0.0284	0.0282	0.0285	0.0277	0.0286	0.0284	0.0283	0.0278	0.0273	1937	0.0273
1938	0.0271	0.0268	0.0273	0.0259	0.0257	0.0259	0.0257	0.0259	0.0259	0.0254	0.0257	0.0252	1938	0.0252
1939	0.0249	0.0245	0.0237	0.0229	0.0217	0.0221	0.0213	0.0231	0.0278	0.0247	0.0236	0.0226	1939	0.0226
1940	0.0229	0.0228	0.0215	0.0220	0.0246	0.0227	0.0224	0.0223	0.0215	0.0214	0.0199	0.0194	1940	0.0194
1941	0.0213	0.0213	0.0206	0.0196	0.0195	0.0191	0.0191	0.0190	0.0193	0.0182	0.0186	0.0204	1941	0.0204
1942	0.0247	0.0247	0.0244	0.0246	0.0243	0.0244	0.0244	0.0244	0.0244	0.0244	0.0247	0.0246	1942	0.0246
1943	0.0245	0.0246	0.0247	0.0246	0.0244	0.0244	0.0245	0.0245	0.0246	0.0247	0.0248	0.0248	1943	0.0248
1944	0.0248	0.0247	0.0247	0.0248	0.0247	0.0248	0.0247	0.0247	0.0247	0.0247	0.0247	0.0246	1944	0.0246
1945	0.0240	0.0236	0.0236	0.0228	0.0226	0.0217	0.0224	0.0223	0.0221	0.0216	0.0210	0.0199	1945	0.0199
1946	0.0199	0.0198	0.0198	0.0207	0.0209	0.0206	0.0209	0.0217	0.0219	0.0216	0.0220	0.0212	1946	0.0212
1947	0.0214	0.0214	0.0213	0.0217	0.0216	0.0216	0.0214	0.0210	0.0213	0.0217	0.0229	0.0243	1947	0.0243
1948	0.0243	0.0241	0.0241	0.0239	0.0231	0.0238	0.0241	0.0242	0.0242	0.0243	0.0239	0.0237	1948	0.0237
1949	0.0233	0.0231	0.0227	0.0227	0.0227	0.0217	0.0216	0.0210	0.0212	0.0212	0.0212	0.0209	1949	0.0209
1950	0.0215	0.0214	0.0215	0.0214	0.0213	0.0216	0.0214	0.0214	0.0220	0.0225	0.0224	0.0224	1950	0.0224
1951	0.0221	0.0228	0.0241	0.0248	0.0254	0.0259	0.0252	0.0246	0.0253	0.0254	0.0264	0.0269	1951	0.0269
1952	0.0268	0.0269	0.0263	0.0254	0.0257	0.0259	0.0261	0.0267	0.0277	0.0269	0.0272	0.0279	1952	0.0279
1953	0.0279	0.0287	0.0294	0.0303	0.0314	0.0301	0.0301	0.0303	0.0284	0.0281	0.0286	0.0274	1953	0.0274
1954	0.0291	0.0279	0.0278	0.0273	0.0279	0.0272	0.0266	0.0269	0.0271	0.0271	0.0274	0.0272	1954	0.0272
1955	0.0286	0.0292	0.0288	0.0290	0.0287	0.0293	0.0300	0.0301	0.0298	0.0292	0.0295	0.0295	1955	0.0295
1956	0.0292	0.0293	0.0303	0.0311	0.0299	0.0299	0.0313	0.0325	0.0324	0.0329	0.0333	0.0345	1956	0.0345
1957	0.0328	0.0328	0.0331	0.0345	0.0348	0.0361	0.0365	0.0367	0.0364	0.0369	0.0340	0.0323	1957	0.0323
1958	0.0330	0.0325	0.0321	0.0311	0.0313	0.0324	0.0343	0.0371	0.0380	0.0374	0.0368	0.0382	1958	0.0382
1959	0.0408	0.0402	0.0403	0.0414	0.0417	0.0419	0.0417	0.0423	0.0429	0.0421	0.0432	0.0447	1959	0.0447
1960	0.0441	0.0429	0.0411	0.0426	0.0417	0.0407	0.0382	0.0390	0.0387	0.0391	0.0399	0.0380	1960	0.0380
1961	0.0404	0.0392	0.0397	0.0391	0.0397	0.0404	0.0404	0.0410	0.0403	0.0400	0.0404	0.0415	1961	0.0415
1962	0.0419	0.0414	0.0398	0.0394	0.0393	0.0401	0.0412	0.0401	0.0398	0.0395	0.0396	0.0395	1962	0.0395
1963	0.0398	0.0400	0.0401	0.0405	0.0406	0.0407	0.0407	0.0408	0.0410	0.0415	0.0414	0.0417	1963	0.0417
1964	0.0421	0.0424	0.0424	0.0423	0.0422	0.0419	0.0421	0.0423	0.0421	0.0421	0.0422	0.0423	1964	0.0423
1965	0.0422	0.0424	0.0422	0.0422	0.0423	0.0423	0.0424	0.0428	0.0433	0.0433	0.0441	0.0450	1965	0.0450
1966	0.0457	0.0477	0.0460	0.0467	0.0473	0.0477	0.0482	0.0499	0.0480	0.0467	0.0480	0.0455	1966	0.0455
1967	0.0448	0.0465	0.0455	0.0477	0.0482	0.0507	0.0505	0.0514	0.0517	0.0549	0.0567	0.0556	1967	0.0556
1968	0.0536	0.0542	0.0560	0.0547	0.0547	0.0534	0.0517	0.0520	0.0531	0.0543	0.0566	0.0598	1968	0.0598
1969	0.0617	0.0618	0.0620	0.0593	0.0635	0.0623	0.0621	0.0630	0.0677	0.0653	0.0676	0.0687	1969	0.0687
1970	0.0693	0.0651	0.0661	0.0699	0.0743	0.0709	0.0687	0.0694	0.0680	0.0693	0.0637	0.0648	1970	0.0648

* Compound annual return

Table A-9 (continued)

Long-Term Government Bonds: Yields

From January 1971 to December 2005

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec
1971	0.0612	0.0629	0.0593	0.0619	0.0624	0.0641	0.0643	0.0610	0.0598	0.0588	0.0596	0.0597	1971	0.0597
1972	0.0606	0.0602	0.0613	0.0615	0.0597	0.0607	0.0593	0.0595	0.0606	0.0591	0.0577	0.0599	1972	0.0599
1973	0.0685	0.0688	0.0686	0.0687	0.0703	0.0710	0.0760	0.0728	0.0703	0.0689	0.0712	0.0726	1973	0.0726
1974	0.0740	0.0748	0.0783	0.0816	0.0810	0.0812	0.0823	0.0855	0.0837	0.0795	0.0771	0.0760	1974	0.0760
1975	0.0796	0.0788	0.0824	0.0852	0.0836	0.0813	0.0829	0.0844	0.0862	0.0819	0.0838	0.0805	1975	0.0805
1976	0.0802	0.0802	0.0792	0.0797	0.0821	0.0807	0.0805	0.0790	0.0781	0.0779	0.0749	0.0721	1976	0.0721
1977	0.0764	0.0775	0.0772	0.0771	0.0765	0.0754	0.0768	0.0754	0.0764	0.0781	0.0777	0.0803	1977	0.0803
1978	0.0816	0.0822	0.0831	0.0838	0.0852	0.0865	0.0858	0.0843	0.0860	0.0889	0.0877	0.0898	1978	0.0898
1979	0.0886	0.0908	0.0902	0.0922	0.0903	0.0877	0.0895	0.0907	0.0927	0.1034	0.1009	0.1012	1979	0.1012
1980	0.1114	0.1186	0.1239	0.1076	0.1037	0.1006	0.1074	0.1140	0.1185	0.1231	0.1230	0.1199	1980	0.1199
1981	0.1211	0.1283	0.1248	0.1332	0.1265	0.1304	0.1370	0.1445	0.1482	0.1384	0.1220	0.1334	1981	0.1334
1982	0.1415	0.1402	0.1387	0.1348	0.1358	0.1412	0.1352	0.1254	0.1183	0.1112	0.1125	0.1095	1982	0.1095
1983	0.1113	0.1060	0.1083	0.1051	0.1112	0.1119	0.1198	0.1210	0.1157	0.1188	0.1176	0.1197	1983	0.1197
1984	0.1180	0.1217	0.1253	0.1284	0.1381	0.1374	0.1293	0.1270	0.1235	0.1173	0.1169	0.1170	1984	0.1170
1985	0.1127	0.1209	0.1181	0.1162	0.1062	0.1055	0.1091	0.1068	0.1082	0.1051	0.1011	0.0956	1985	0.0956
1986	0.0958	0.0841	0.0766	0.0782	0.0848	0.0790	0.0809	0.0763	0.0827	0.0803	0.0779	0.0789	1986	0.0789
1987	0.0778	0.0763	0.0795	0.0859	0.0880	0.0877	0.0907	0.0936	0.0992	0.0926	0.0931	0.0920	1987	0.0920
1988	0.0852	0.0854	0.0901	0.0929	0.0952	0.0917	0.0947	0.0950	0.0917	0.0889	0.0923	0.0918	1988	0.0918
1989	0.0903	0.0935	0.0929	0.0918	0.0878	0.0821	0.0801	0.0841	0.0847	0.0810	0.0808	0.0816	1989	0.0816
1990	0.0865	0.0876	0.0889	0.0924	0.0883	0.0864	0.0860	0.0920	0.0914	0.0898	0.0858	0.0844	1990	0.0844
1991	0.0837	0.0841	0.0844	0.0837	0.0845	0.0860	0.0850	0.0818	0.0790	0.0791	0.0789	0.0730	1991	0.0730
1992	0.0776	0.0777	0.0797	0.0803	0.0781	0.0765	0.0726	0.0725	0.0710	0.0741	0.0748	0.0726	1992	0.0726
1993	0.0725	0.0698	0.0702	0.0701	0.0701	0.0668	0.0656	0.0623	0.0627	0.0623	0.0651	0.0654	1993	0.0654
1994	0.0637	0.0682	0.0725	0.0745	0.0759	0.0774	0.0746	0.0761	0.0800	0.0809	0.0808	0.0799	1994	0.0799
1995	0.0780	0.0758	0.0755	0.0745	0.0677	0.0670	0.0691	0.0674	0.0663	0.0641	0.0623	0.0603	1995	0.0603
1996	0.0609	0.0659	0.0684	0.0706	0.0717	0.0703	0.0707	0.0726	0.0704	0.0671	0.0643	0.0673	1996	0.0673
1997	0.0689	0.0694	0.0723	0.0705	0.0701	0.0688	0.0637	0.0672	0.0649	0.0623	0.0614	0.0602	1997	0.0602
1998	0.0589	0.0599	0.0602	0.0604	0.0592	0.0576	0.0584	0.0547	0.0517	0.0540	0.0535	0.0542	1998	0.0542
1999	0.0536	0.0587	0.0592	0.0594	0.0615	0.0627	0.0639	0.0649	0.0646	0.0651	0.0662	0.0682	1999	0.0682
2000	0.0666	0.0646	0.0618	0.0630	0.0640	0.0622	0.0611	0.0594	0.0612	0.0600	0.0576	0.0558	2000	0.0558
2001	0.0562	0.0549	0.0559	0.0593	0.0594	0.0590	0.0561	0.0546	0.0542	0.0506	0.0553	0.0575	2001	0.0575
2002	0.0569	0.0563	0.0604	0.0575	0.0578	0.0566	0.0544	0.0510	0.0480	0.0508	0.0521	0.0484	2002	0.0484
2003	0.0495	0.0472	0.0486	0.0481	0.0436	0.0452	0.0542	0.0532	0.0490	0.0518	0.0519	0.0511	2003	0.0511
2004	0.0499	0.0483	0.0474	0.0531	0.0539	0.0532	0.0523	0.0493	0.0488	0.0478	0.0502	0.0484	2004	0.0484
2005	0.0465	0.0479	0.0488	0.0461	0.0440	0.0429	0.0456	0.0432	0.0464	0.0484	0.0481	0.0461	2005	0.0461

2003

MERGENT® PUBLIC UTILITY MANUAL

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ELECTRIC UTILITY COMMON STOCKS

END-OF-MONTH AVERAGES

MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2002	188.15	195.40	213.60	213.30	214.30	204.20	199.10	175.20	184.30	165.00	161.10	162.80	169.50
2001	207.31	199.03	207.83	219.00	224.50	223.80	210.30	199.40	202.30	204.50		189.30	200.50
2000	167.69	146.31	131.96	131.86	147.83	149.08	142.71	152.93	163.75	200.12	202.97	215.69	227.09
1999	160.23	169.51	160.83	159.32	167.11	179.81	170.23	165.86	163.69	153.55	155.69	139.85	137.30
1998	161.03	148.60	151.93	160.83	153.95	154.46	159.51	151.14	160.47	168.13	164.59	176.96	181.84
1997	136.36	135.20	134.70	130.70	126.50	129.60	134.10	136.90	131.90	136.40	138.70	145.90	155.73
1996	133.27	145.90	139.60	134.40	127.20	133.00	134.20	123.60	126.70	127.40	133.00	138.20	136.00
1995	130.53	124.10	123.50	119.90	122.90	131.00	129.70	130.30	130.00	137.50	138.00	136.50	142.90
1994	121.60	142.60	133.20	127.00	127.50	118.80	112.80	118.80	119.70	114.40	113.60	114.00	115.50
1993	151.22	144.48	152.96	152.36	150.37	149.20	151.26	155.07	158.79	155.80	153.40	144.20	146.70
1992	137.07	135.87	133.16	131.76	135.72	136.89	135.01	⊞141.92	⊞138.59	138.94	137.75	138.18	⊞141.06
1991	126.97	116.65	121.00	123.29	122.25	120.48	119.19	124.25	127.80	132.77	134.13	137.81	144.02
1990	112.61	116.90	116.81	114.26	107.68	111.55	112.50	113.38	104.90	104.47	114.55	116.56>	117.77
1989	110.45	103.23	99.81	98.64	102.49	107.29	111.25	117.12	113.70	113.73	116.28	119.35	122.52
1988	97.99	102.86	100.38	95.22	91.65	95.42	96.88	96.51	96.27	98.81	101.32	99.67	100.94
1987	105.90	123.06	118.35	113.48	107.10	103.30	105.83	102.44	105.66	102.59	98.39	96.30	94.24
1986	111.11	97.44	106.11	109.01	102.23	104.88	109.23	117.40	125.66	112.15	117.57	117.99	113.66
1985	87.24	80.47	81.05	83.66	85.91	89.32	92.81	87.22	89.43	83.59	88.10	90.39	94.98
1984	71.16	71.08	68.08	66.74	65.95	66.09	66.49	68.12	70.45	74.77	77.05	78.99	80.16
1983	74.04	72.53	73.59	73.79	75.39	75.35	71.73	72.19	72.50	74.88	78.18	76.37	72.03
1982	63.56	57.95	60.16	60.77	63.15	63.23	61.15	59.16	66.63	66.10	66.83	67.34	70.26
1981	55.41	53.19	52.61	54.43	53.43	54.00	56.04	56.33	56.82	54.99	56.01	59.83	57.20
1980	54.80	54.57	49.93	50.16	57.14	58.51	60.08	57.83	56.40	54.51	52.63	51.44	54.42
1979	60.28	63.99	62.14	62.36	58.69	60.35	61.03	61.41	62.05	59.79	55.84	59.27	56.41
1978	63.54	65.23	64.66	64.95	63.46	63.77	63.56	65.39	65.16	64.90	60.10	61.54	59.75
1977	67.55	66.45	64.90	64.84	66.03	67.36	70.23	70.56	67.91	68.53	66.82	68.76	68.19
1976	60.10	60.68	57.82	57.32	57.76	55.35	57.07	58.62	60.91	63.45	61.85	64.11	66.29
1975	51.25	49.60	49.13	47.80	46.99	49.62	55.06	51.58	51.33	49.66	53.19	55.37	55.66
1974	48.26	63.23	63.72	61.31	50.33	47.49	43.43	44.90	39.93	39.01	42.91	41.67	41.17
1973	71.21	79.43	77.54	75.20	74.73	74.69	72.89	69.70	67.87	72.38	68.21	60.95	60.87
1972	80.20	84.18	81.48	80.77	77.94	77.13	75.27	75.11	78.25	78.48	83.36	86.86	83.61
1971	84.16	90.82	87.70	89.49	85.82	81.51	84.95	83.31	79.70	78.81	82.41	79.80	85.56
1970	79.06	80.31	85.35	87.44	80.06	74.91	68.96	74.55	77.17	75.66	74.15	81.54	88.59
1969	94.55	106.49	101.51	99.88	99.64	99.81	94.53	92.47	91.13	86.29	92.25	85.98	84.62
1968	98.37	97.75	97.15	92.66	92.93	92.08	100.10	99.76	99.25	98.46	98.83	107.33	104.04
1967	101.87	108.12	105.18	106.81	108.90	102.58	100.73	103.04	99.63	99.76	93.63	95.92	98.19
1966	102.90	111.34	106.81	105.41	106.33	102.45	99.95	101.03	92.51	94.57	104.92	103.47	105.99
1965	117.08	119.00	118.81	118.85	119.57	118.21	114.22	114.76	115.46	116.95	118.38	115.84	114.86
1964	108.76	103.69	104.23	103.13	104.00	104.11	105.40	110.76	110.86	112.67	115.11	115.62	115.54
1963	102.79	102.52	99.88	101.40	102.94	103.80	102.10	102.44	107.57	105.14	102.53	100.82	102.31
1962	91.50	95.14	97.76	98.87	96.45	86.79	81.74	87.72	90.12	87.42	86.83	92.64	96.49
1961	90.55	80.47	82.66	85.20	85.54	88.57	85.87	88.06	92.73	94.50	99.77	103.91	99.32
1960	69.82	64.67	66.13	66.66	67.30	67.31	71.51	71.12	73.59	70.25	70.27	72.24	76.82
1959	66.35	66.66	67.40	68.12	67.24	66.28	64.25	66.49	67.39	65.69	65.51	65.38	65.77
1958	57.96	53.04	53.27	54.16	56.05	56.78	57.74	58.21	57.20	59.38	61.08	62.18	66.37
1957	49.42	50.05	49.98	49.88	50.37	51.85	48.96	49.60	48.52	47.67	47.15	48.65	50.30
1956	49.62	49.10	49.66	51.38	49.74	49.10	49.55	51.98	50.36	48.42	48.46	48.72	48.96
1955	49.24	46.94	48.59	47.97	49.12	48.54	49.21	51.39	51.43	49.83	48.53	49.90	49.35
1954	44.30	40.87	41.42	42.56	42.91	43.79	43.91	46.67	45.44	45.90	44.18	46.33	47.56
1953	37.80	38.40	38.21	37.81	36.96	37.08	36.02	36.81	37.16	37.20	38.59	39.70	39.61
1952	35.48	34.42	34.41	34.73	33.97	34.57	34.65	35.09	36.15	36.34	36.25	37.36	37.85
1951	32.55	31.86	32.82	31.77	31.78	31.99	31.70	32.67	33.13	32.87	32.94	33.26	33.85
1950	31.23	31.60	31.91	32.08	32.47	33.51	31.07	29.73	30.07	30.58	30.55	30.34	30.81
1949	28.37	27.15	26.93	27.41	27.75	27.62	27.02	28.03	28.76	29.58	29.82	29.81	30.57
1948	27.34	27.32	26.25	26.91	27.05	28.41	28.61	27.88	27.77	27.42	28.41	25.80	26.20
1947	29.53	32.31	31.87	30.53	29.68	29.30	30.39	30.36	30.37	29.76	29.02	25.20	25.60
1946	34.05	35.95	33.70	35.23	35.88	36.62	35.72	35.05	33.07	30.93	31.84	31.86	32.71
1945	26.29	22.35	23.46	22.47	24.41	24.73	25.61	25.71	25.96	28.11	29.92	31.62	31.14
1944	20.90	20.56	20.72	20.52	20.26	20.58	21.81	20.40	21.88	21.24	21.11	20.60	21.09
1943	18.87	15.58	16.63	16.83	18.64	19.53	20.01	19.69	19.33	20.10	20.40	18.65	21.01
1942	12.92	13.81	13.07	12.03	11.41	12.46	12.57	12.44	12.21	12.59	14.18	13.93	14.29
1941	18.16	21.90	21.25	20.45	18.57	17.73	18.22	18.98	18.53	17.87	16.24	14.74	13.45
1940	25.64	28.87	28.45	28.78	28.13	22.55	25.94	25.94	25.46	24.86	24.28	22.14	22.22
1939	28.02	27.65	29.88	25.71	26.15	27.90	26.54	29.89	27.67	28.81	28.83	28.34	28.85
1938	24.27	23.14	23.84	18.93	21.83	21.76	25.36	25.34	23.94	24.12	28.71	26.69	27.55
1937	33.08	42.46	40.71	38.18	35.13	32.68	31.17	36.40	32.89	28.67	27.14	27.26	24.24
1936	40.28	40.72	38.61	38.51	35.16	37.83	38.78	42.52	41.97	41.61	43.71	42.31	41.60
1935	27.20	20.48	17.90	19.77	21.92	24.52	26.83	29.15	30.86	30.25	33.92	34.72	36.06
1934	27.84	34.39	33.44	32.89	31.59	28.75	29.85	24.97	25.28	25.29	23.45	23.08	21.06
1933	34.37	37.98	30.47	26.70	33.26	39.72	45.79	40.01	39.48	32.02	29.49	28.76	28.73
1932	36.40	42.50	45.23	39.84	33.67	24.00	24.04	32.19	37.37	43.38	38.40	36.76	39.42
1931	69.80	80.32	91.34	89.01	78.91	70.52	79.10	73.52	74.84	50.46	55.38	50.99	43.23

DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2002	9.13	9.13	9.25	9.25	9.21	9.31	9.36	9.38	9.25	9.09	8.66	8.79	8.83
2001	8.69	7.83	8.59	8.86	8.68	8.69	8.69	8.69	8.77	8.77		8.94	8.95
2000	8.27	8.19	8.22	7.89	7.90	7.87	7.83	8.15	7.76	8.78	8.75	9.23	8.71
1999	8.10	8.15	8.09	8.35	8.17	8.16	8.00	8.01	8.13	8.07	8.09	7.97	8.06
1998	7.83	9.06	7.85	7.64	7.69	7.64	7.67	7.67	7.61	7.51	7.59	8.01	8.01
1997	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1996	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1995	9.02	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.06	9.06	9.06
1994	8.96	8.94	8.94	8.94	8.95	8.96	8.96	8.96	8.96	8.96	9.01	9.01	9.01
1993	8.99	8.92	8.96	8.96	8.97	8.98	9.00	9.00	9.00	9.00	9.04	9.05	9.04
1992	9.05	9.12	9.16	9.16	9.17	9.19	9.22	9.23	9.23	8.76	8.79	8.80	8.82
1991	8.95	8.87	8.91	8.91	8.92	8.92	8.95	8.95	8.95	8.95	8.99	9.00	9.02
1990	8.79	8.99	9.03	9.03	8.70	8.69	8.72	8.72	8.72	8.72	8.72	8.73	8.76
1989	8.82	8.76	8.78	8.78	8.80	8.81	8.84	8.84	8.84	8.84	8.84	8.85	8.85
1988	8.87	9.17	9.17	8.95	8.98	8.99	9.03	8.69	8.69	8.69	8.69	8.69	8.71
1987	9.12	9.09	9.09	9.09	9.12	9.13	9.13	9.13	9.13	9.14	9.14	9.14	9.12
1986	8.89	8.80	8.80	8.80	8.84	8.89	8.89	8.94	8.94	8.94	8.95	8.96	8.97
1985	8.61	8.44	8.46	8.48	8.52	8.61	8.66	8.66	8.66	8.69	8.69	8.70	8.71
1984	8.26	8.11	8.12	8.14	8.17	8.25	8.30	8.31	8.34	8.34	8.34	8.35	8.37
1983	7.87	7.73	7.75	7.76	7.80	7.86	7.86	7.87	7.87	7.97	7.97	7.98	8.00
1982	7.43	7.20	7.22	7.31	7.32	7.42	7.44	7.48	7.48	7.55	7.56	7.57	7.64
1981	6.99	6.83	6.85	6.85	6.87	6.91	6.96	6.99	6.99	7.13	7.13	7.15	7.16
1980	6.58	6.45	6.52	6.52	6.53	6.56	6.58	6.59	6.60	6.65	6.65	6.67	6.67
1979	6.22	6.07	6.07	6.16	6.17	6.17	6.20	6.22	6.26	6.31	6.32	6.33	6.34
1978	5.81	5.76	5.77	5.77	5.78	5.78	5.79	5.80	5.80	5.83	5.83	5.87	5.98
1977	5.54	5.39	5.40	5.51	5.52	5.54	5.55	5.57	5.57	5.57	5.58	5.59	5.68
1976	5.18	5.11	5.13	5.14	5.15	5.16	5.18	5.18	5.18	5.20	5.22	5.25	5.35
1975	4.97	4.96	4.96	4.96	4.96	4.96	4.96	4.97	4.97	4.97	4.97	4.98	4.99
1974	4.83	5.08	5.09	5.12	4.56	4.57	4.57	4.82	4.82	4.82	4.83	4.83	4.83
1973	5.01	4.95	4.98	4.99	4.99	4.99	5.00	5.01	5.02	5.03	5.03	5.03	5.04
1972	4.87	4.83	4.83	4.86	4.86	4.86	4.86	4.86	4.88	4.89	4.89	4.90	4.92
1971	4.77	4.74	4.74	4.75	4.78	4.78	4.78	4.78	4.78	4.78	4.78	4.79	4.81
1970	4.70	4.64	4.64	4.70	4.70	4.70	4.71	4.71	4.71	4.71	4.71	4.72	4.73
1969	4.61	4.58	4.58	4.59	4.59	4.61	4.61	4.61	4.62	4.62	4.62	4.63	4.63
1968	4.50	4.44	4.45	4.46	4.48	4.48	4.48	4.50	4.50	4.55	4.55	4.56	4.58
1967	4.34	4.18	4.20	4.27	4.27	4.32	4.38	4.39	4.39	4.39	4.40	4.41	4.44
1966	4.11	4.03	4.03	4.08	4.08	4.09	4.10	4.12	4.14	4.14	4.14	4.15	4.18
1965	3.86	3.73	3.73	3.80	3.80	3.80	3.83	3.84	3.88	3.90	3.96	3.99	4.02
1964	3.43	3.33	3.34	3.38	3.38	3.38	3.38	3.39	3.46	3.48	3.49	3.49	3.68
1963	3.21	3.07	3.10	3.16	3.16	3.16	3.21	3.23	3.30	3.30	3.30	3.32	3.33
1962	2.97	2.86	2.86	2.91	2.91	2.97	2.98	2.98	2.99	3.02	3.03	3.05	3.07
1961	2.81	2.74	2.75	2.77	2.79	2.79	2.80	2.81	2.83	2.83	2.84	2.85	2.86

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1960	2.68	2.67	2.67	2.67	2.67	2.67	2.67	2.68	2.68	2.69	2.69	2.71	2.74
1959	2.61	2.59	2.59	2.59	2.60	2.60	2.60	2.60	2.62	2.63	2.63	2.64	2.64
1958	2.50	2.46	2.46	2.46	2.50	2.50	2.50	2.51	2.51	2.51	2.51	2.52	2.57
1957	2.43	2.40	2.41	2.42	2.43	2.43	2.43	2.42	2.42	2.44	2.44	2.45	2.45
1956	2.32	2.27	2.28	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.33	2.37	2.37
1955	2.21	2.14	2.14	2.18	2.18	2.21	2.23	2.23	2.23	2.24	2.24	2.27	2.27
1954	2.13	2.09	2.11	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.14
1953	2.01	1.93	1.94	1.95	1.96	1.98	2.01	2.01	2.07	2.07	2.07	2.09	2.09
1952	1.91	1.90	1.89	1.91	1.91	1.91	1.91	1.91	1.92	1.92	1.92	1.92	1.92
1951	1.88	1.85	1.85	1.86	1.87	1.87	1.87	1.87	1.88	1.90	1.90	1.90	1.90
1950	1.76	1.69	1.70	1.70	1.71	1.74	1.74	1.78	1.78	1.78	1.84	1.85	1.85
1949	1.66	1.63	1.63	1.63	1.66	1.66	1.67	1.67	1.66	1.68	1.68	1.68	1.68
1948	1.60	1.58	1.58	1.59	1.59	1.59	1.59	1.59	1.59	1.61	1.61	1.61	1.61
1947	1.56	1.49	1.55	1.55	1.56	1.56	1.57	1.58	1.58	1.58	1.58	1.58	1.58
1946	1.43	1.38	1.40	1.42	1.42	1.41	1.43	1.43	1.45	1.45	1.46	1.47	1.48
1945	1.30	1.24	1.25	1.26	1.26	1.27	1.28	1.30	1.32	1.34	1.36	1.35	1.35
1944	1.31	1.30	1.30	1.31	1.32	1.28	1.29	1.30	1.30	1.31	1.34	1.35	1.35
1943	1.28	1.28	1.28	1.24	1.24	1.24	1.23	1.23	1.29	1.31	1.33	1.33	1.26
1942	1.26	1.27	1.27	1.27	1.27	1.27	1.25	1.24	1.24	1.23	1.23	1.24	1.28
1941	1.44	1.51	1.51	1.51	1.51	1.51	1.52	1.45	1.46	1.45	1.33	1.27	1.27
1940	1.54	1.52	1.52	1.52	1.54	1.54	1.54	1.54	1.54	1.54	1.55	1.58	1.57
1939	1.48	1.44	1.44	1.46	1.46	1.46	1.50	1.50	1.50	1.51	1.51	1.51	1.51
1938	1.50	1.65	1.65	1.54	1.47	1.42	1.48	1.48	1.48	1.46	1.46	1.49	1.45
1937	1.74	1.78	1.78	1.78	1.76	1.76	1.77	1.77	1.76	1.69	1.69	1.70	1.68
1936	1.48	1.33	1.33	1.33	1.33	1.33	1.35	1.51	1.53	1.60	1.64	1.69	1.78
1935	1.32	1.36	1.36	1.34	1.34	1.31	1.31	1.29	1.29	1.29	1.28	1.29	1.33
1934	1.60	1.73	1.73	1.73	1.58	1.58	1.55	1.55	1.58	1.58	1.58	1.58	1.42
1933	1.95	2.21	2.21	2.09	1.99	1.99	1.97	1.97	1.90	1.82	1.75	1.75	1.75
1932	2.63	3.19	3.12	3.03	2.96	2.95	2.52	2.38	2.38	2.27	2.27	2.27	2.23
1931	3.47	3.65	3.69	3.66	3.55	3.54	3.53	3.52	3.49	3.39	3.22	3.21	3.20

YIELD - %

Year	Aver.	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
2002	4.91	4.78	4.33	4.34	4.30	4.56	4.70	5.36	5.02	5.51	5.38	5.40	5.21
2001	4.20	3.93	4.13	4.05	3.87	3.88	4.13	4.36	4.33	4.29		4.72	4.47
2000	8.07	5.59	6.23	5.99	5.34	5.28	5.49	5.33	4.74	4.39	4.31	4.28	3.84
1999	5.09	4.81	5.03	5.24	4.89	4.54	4.70	4.83	4.97	5.25	5.19	5.70	5.83
1998	4.88	6.10	5.17	4.75	5.00	4.95	4.81	5.07	4.74	4.47	4.61	4.53	4.40
1997	6.66	6.70	6.73	6.93	7.16	6.99	6.76	6.62	6.87	6.64	6.53	6.21	5.82
1996	6.81	6.21	6.49	6.74	7.12	6.81	6.75	7.33	7.15	7.11	6.81	6.56	6.67
1995	6.93	7.26	7.30	7.52	7.33	6.88	6.95	6.92	6.93	6.55	6.57	6.64	6.34
1994	7.41	6.27	6.71	7.04	7.02	7.54	7.94	7.54	7.49	7.83	7.93	7.90	7.80
1993	5.95	6.17	5.86	5.88	5.97	6.02	5.95	5.80	5.67	5.78	5.87	6.27	6.16
1992	6.61	6.71	6.88	6.95	6.76	6.71	6.83	[R]6.50	[R]6.66	6.30	6.38	6.37	6.25
1991	7.07	7.60	7.36	7.23	7.30	7.40	7.51	7.20	7.00	6.74	6.70	6.53	6.26
1990	7.82	7.69	7.73	7.90	8.08	7.79	7.75	7.69	8.31	8.35	7.61	7.49	7.44
1989	8.02	8.49	8.80	8.90	8.59	8.21	7.95	7.55	7.77	7.77	7.60	7.42	7.22
1988	9.06	8.92	9.14	9.40	9.80	9.42	9.32	9.00	9.03	8.79	8.58	8.72	8.63
1987	8.67	7.39	7.68	8.01	8.52	8.84	8.63	8.91	8.64	8.91	9.29	9.49	9.68
1986	8.00	9.03	8.29	8.07	8.65	8.48	8.14	7.61	7.11	7.97	7.61	7.59	7.89
1985	9.89	10.49	10.44	10.14	9.92	9.64	9.33	9.93	9.68	10.40	9.86	9.62	9.17
1984	11.61	11.41	11.93	12.20	12.39	12.48	12.48	12.20	11.84	11.15	10.82	10.57	10.44
1983	10.63	10.66	10.53	10.52	10.35	10.43	10.96	10.90	10.86	10.64	10.19	10.45	11.11
1982	11.69	12.42	12.00	12.03	11.59	11.73	12.17	12.64	11.23	11.42	11.31	11.24	10.87
1981	12.62	12.84	13.02	12.59	12.86	12.80	12.42	12.41	12.30	12.97	12.73	11.95	12.52
1980	12.01	11.82	13.06	13.00	11.43	11.21	10.95	11.40	11.70	12.20	12.64	12.97	12.26
1979	10.32	9.49	9.77	9.88	10.50	10.22	10.16	10.13	10.09	10.55	11.32	10.68	11.24
1978	9.14	8.83	8.92	8.88	9.11	9.06	9.11	8.87	8.90	8.98	9.70	9.54	10.01
1977	8.20	8.11	8.32	8.50	8.36	8.22	7.90	7.89	8.20	8.13	8.35	8.13	8.33
1976	8.62	8.42	8.87	8.97	8.92	9.32	9.08	8.84	8.50	8.20	8.44	8.19	7.92
1975	9.70	10.00	10.10	10.38	10.56	10.00	9.01	9.64	9.68	10.01	9.34	8.99	8.97
1974	10.01	8.03	7.99	8.35	9.06	9.62	10.52	10.74	12.07	12.36	11.26	11.59	11.73
1973	7.04	6.23	6.42	6.64	6.68	6.86	7.19	7.40	6.95	7.37	8.25	8.28	8.28
1972	6.07	5.74	5.93	6.02	6.24	6.30	6.46	6.47	6.24	6.23	5.87	5.64	5.88
1971	5.70	5.22	5.40	5.29	5.56	5.86	5.77	5.74	5.96	6.03	5.80	6.09	5.62
1970	5.94	5.78	5.44	5.38	5.87	6.27	6.83	6.32	6.10	6.23	6.35	5.79	5.34
1969	4.88	4.30	4.51	4.60	4.61	4.62	4.88	4.99	5.07	5.35	5.68	5.38	5.47
1968	4.57	4.54	4.58	4.81	4.82	4.87	4.48	4.51	4.53	4.62	4.60	4.25	4.40
1967	4.26	3.87	3.99	4.00	3.92	4.21	4.35	4.26	4.41	4.40	4.70	4.60	4.52
1966	3.99	3.62	3.77	3.87	3.84	3.99	4.10	4.08	4.08	4.38	3.95	4.01	3.94
1965	3.30	3.13	3.14	3.20	3.18	3.21	3.35	3.35	3.36	3.33	3.35	3.44	3.50
1964	3.15	3.21	3.20	3.28	3.25	3.25	3.21	3.06	3.12	3.09	3.03	3.02	3.19
1963	3.12	2.99	3.10	3.06	3.07	3.04	3.14	3.13	3.00	3.14	3.22	3.29	3.25
1962	3.25	3.01	2.93	2.94	3.02	3.42	3.65	3.40	3.32	3.45	3.49	3.29	3.18
1961	3.10	3.40	3.33	3.25	3.26	3.15	3.26	3.19	3.05	2.99	2.85	2.74	2.88
1960	3.84	4.13	4.04	4.01	3.97	3.97	3.73	3.77	3.64	3.83	3.83	3.75	3.57
1959	3.94	3.89	3.84	3.80	3.87	3.92	4.05	3.91	3.89	4.00	4.01	4.04	4.01
1958	4.33	4.64	4.62	4.54	4.46	4.40	4.33	4.31	4.39	4.23	4.11	4.05	3.87
1957	4.92	4.80	4.82	4.85	4.82	4.69	4.96	4.88	4.99	5.12	5.17	5.04	4.89
1956	4.68	4.62	4.59	4.52	4.66	4.73	4.68	4.46	4.61	4.79	4.81	4.86	4.84
1955	4.50	4.56	4.40	4.54	4.44	4.55	4.53	4.34	4.34	4.50	4.62	4.55	4.60
1954	4.81	5.11	5.09	5.00	4.96	4.86	4.85	4.56	4.69	4.64	4.82	4.60	4.50
1953	5.33	5.03	5.08	5.16	5.30	5.34	5.58	5.46	5.57	5.56	5.36	5.26	5.28
1952	5.39	5.52	5.49	5.50	5.62	5.53	5.51	5.44	5.31	5.28	5.30	5.14	5.07
1951	5.77	5.81	5.64	5.85	5.88	5.85	5.90	5.72	5.67	5.78	5.77	5.71	5.61
1950	5.66	5.35	5.33	5.30	5.27	5.19	5.60	5.99	5.92	5.82	6.02	6.10	6.00
1949	5.86	6.00	6.05	5.95	5.98	6.03	6.18	5.96	5.77	5.68	5.63	5.64	5.50
1948	5.85	5.78	6.02	5.91	5.88	5.60	5.56	5.70	5.73	5.87	5.67	6.24	6.22
1947	5.32	4.61	4.86	5.08	5.26	5.32	5.17	5.20	5.20	5.31	5.44	6.23	6.17
1946	4.23	3.84	4.15	4.03	3.96	3.85	4.00	4.08	4.38	4.69	4.59	4.61	4.52
1945	4.99	5.55	5.53	5.61	5.16	5.14	5.00	5.06	5.08	4.77	4.55	4.27	4.40
1944	6.28	6.32	6.27	6.58	6.52	6.22	5.91	6.57	5.94	6.17	6.35	6.55	6.40
1943	6.85	8.22	7.70	7.37	6.65	6.35	6.15	6.25	6.67	6.52	6.52	7.13	6.66
1942	9.76	9.20	9.72	10.56	11.13	10.19	9.94	9.97	10.16	9.77	8.67	8.90	8.96
1941	8.02	6.89	7.11	7.38	8.13	8.52	8.34	7.64	7.88	8.11	8.19	8.62	9.44
1940	6.07	5.26	5.34	5.28	5.47	6.83	5.94	5.94	6.05	6.19	6.38	7.14	7.07
1939	5.30	5.21	4.82	5.68	5.58	5.25	5.65	5.02	5.42	5.24	5.24	5.33	5.23
1938	6.27	7.13	6.92	8.14	6.73	6.53	5.84	5.84	6.18	6.05	5.09	5.58	5.26
1937	5.40	4.19	4.37	4.66	5.01	5.39	5.68	4.86	5.35	5.89	6.23	6.24	6.93
1936	3.67	3.27	3.44	3.45	3.78	3.52	3.48	3.55	3.65	3.85	3.75	3.99	4.28
1935	5.12	6.64	7.60	6.78	6.11	5.34	4.88	4.43	4.18	4.26	3.77	3.72	3.69
1934	5.85	5.03	5.17	5.26	5.00	5.50	5.19	6.21	6.25	6.25	6.74	6.85	6.74
1933	5.81	5.82	7.25	7.83	5.98	5.01	4.30	4.92	4.81	5.68	5.93	6.08	6.09
1932	7.52	7.51	6.90	7.61	8.79	12.29	10.48	7.39	6.37	5.23	5.91	6.18	5.63
1931	5.20	4.54	4.04	4.11	4.50	5.02	4.46	4.79	4.66	6.72	5.81	6.30	7.40

Note: [R] Revised.

EARNINGS - WEIGHTED AVERAGE - $ PER SHARE

Year	Year	1Q	2Q	3Q	4Q
2000	8.36	4.31	3.42	6.06	8.36
1999	8.21	8.30	10.80	12.79	8.21
1998	8.79	4.87	3.74	5.62	8.79
1997	4.81	10.30	9.80	9.00	4.81
1996	10.72	13.37	12.82	10.66	10.72
1995	13.41	10.61	11.12	13.25	13.41
1994	10.23	8.07	8.13	8.18	10.23
1993	6.53	11.12	10.86	11.13	6.53
1992	11.03	10.30	9.98	9.73	11.03
1991	10.06	9.20	10.52	10.89	10.06
1990	9.03	10.43	9.25	8.92	9.03
1989	11.07	7.97	8.22	8.54	11.07
1988	7.55	11.27	10.70	10.60	7.55
1987	11.45	12.86	12.63	12.36	11.45
1986	13.13	12.40	12.72	13.17	13.13
1985	12.53	12.66	12.65	12.67	12.53

Year	Year	1Q	2Q	3Q	4Q
1984	12.67	12.35	12.36	12.48	12.67
1983	11.88	10.87	10.87	11.49	11.88
1982	10.90	10.52	10.80	11.06	10.90
1981	10.16	9.35	9.59	10.11	10.16
1980	8.98	8.69	8.58	8.75	8.98
1979	8.95	8.87	8.88	9.20	8.95
1978	8.59	8.27	8.37	8.36	8.59
1977	8.64	8.89	8.91	8.90	8.64
1976	8.15	7.81	7.64	7.86	8.15
1975	7.77	7.70	7.76	7.80	7.77
1974	7.63	7.15	7.22	7.53	7.63
1973	7.55	7.78	7.63	7.60	7.55
1972	7.73	7.27	7.53	7.72	7.73
1971	7.14	6.91	6.88	7.10	7.14
1970	6.89	6.90	6.90	6.82	6.89
1969	6.92	6.74	6.81	6.89	6.92

Stocks Used in Electric Utility Average

American Electric Power Inc.
Constellation Energy Group Inc.
Progress Energy Inc.
Ch Energy Group Inc.
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Res Inc VA New
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
Idacorp Inc.
Ipalco Enterprises Inc.
Nisource Inc.
Oge Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Elec. Power Co.
Public Svc. Enterprise Group
Southern Co.
Teco Energy Inc.
Xcel Energy Inc.

DISCOVERY REQUEST NO. 25:

Regarding Dr. Morin's testimony at page 22, lines 18-20 that "a substantial fraction of bond market participants...hold bonds until they mature," please identify the fraction, the source, and what term is being described, such as 30-years, 20-years, 10-years.

Response:

Table L.212 at *www. Federalreserve.gov/releases/z1/current/data* reports the holdings of bonds issued in the USA by U.S. and foreign corporations. From this data, it is clear that financial institutions own the majority of corporate debt. The insurance companies and pension funds are seen to own the largest stake. These bond investors, along with the dealers, comprise the "institutional market", where large blocks of bonds are traded. A trade of $1-million-worth of bonds would be considered a small ticket. There is no size limit, and trades involving $500 million or $1 billion at a time can take place. The exact maturity composition of the debt is not available, but we do know that it is long-term.

In fact, as a sign of the strategic importance of long-term institutional bond buyers, the U.S. Federal government who had ceased to issue 30-year Treasury bonds in October 2001, re-introduced the 30-year Treasury bond due to demand from pension funds and large long-term institutional investors.

These financial institutions hold long-term bonds in their portfolios on account of the long-term nature of their liabilities, in effect matching the maturity of their assets and liabilities in order to minimize interest rate risk. While long-term government bonds are exposed to interest rate risk, this is only true if the bonds are sold prior to maturity. Institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

DISCOVERY REQUEST NO. 26:

Regarding Dr. Morin's testimony at page 26, lines 4-10, supply the data sources and show the calculations that lead to the amounts of 7.2%, 6.5% and 7.1%.

Response:

The 7.1% number is the historical market risk premium (MRP) over the income component of long-term Treasury bonds reported in the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook,* compiling historical returns from 1926 to 2005. The relevant table from Ibbotson is attached to the Company's response to CAPD DR No. 24. The long-horizon (1926-2005) market risk premium (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5% reported over the total bond return component.

The 7.2% number is the average of the historical MRP estimate of 7.1% and the prospective estimate of 7.3% described on pages 28-30 of Dr. Morin's testimony.

DISCOVERY REQUEST NO. 28:

Provide a copy of the article referenced at page 29, footnote 8 of Dr. Morin's testimony.

Response:

Please see attached.

Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM

Robert S. Harris, Felicia C. Marston, Dev R. Mishra, and Thomas J. O'Brien*

We estimate ex ante expected returns for a sample of S&P 500 firms over the period 1983-1998. The ex ante estimates show a better overall fit with the domestic version of the single-factor CAPM than with the global version, but the difference is small. This finding has no trend in time and is consistent across groups formed on the basis of relative foreign sales. The findings suggest that for estimating the cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The estimation of a firm's cost of equity capital remains one of the most critical and challenging issues faced by financial managers, analysts, and academicians. Although theory provides several broad approaches, recent survey evidence reports that among large US firms and investors, the capital asset pricing model (CAPM) is by far the most widely used model.

Among the variety of decisions to be made in implementing the CAPM is the choice between a domestic or global index for the market portfolio. Although theory suggests that using a domestic market index is appropriate only for an asset traded in a closed, national market, empirical research has thus far failed to establish whether a global or domestic pricing model performs better with US stocks.

We study the choice between the global and domestic CAPM by examining which of the two models provides the better fit with a sample of *ex ante* expected equity return estimates for large US companies. In contrast to many prior studies that use realized returns, we estimate implied expected returns based on the theory's call for a forward looking measure. The question we ask is whether the domestic or the global version of the single-factor CAPM provides the better fit with the dispersion of the *ex ante* expected return estimates for a sample of S&P 500 equities. Our study period covers 1983 to 1998.

We find that the domestic US CAPM fits the *ex ante* expected return estimates better than does the global CAPM. This result shows no trend over time. We also find that except for a few years in the early 1990s, the better fit of the domestic CAPM holds consistently across subsamples formed on the basis of the relative levels of the firms' foreign sales. However, the difference in fit of the two versions of the CAPM is small.

We also find a positive and significant empirical relation between *ex ante* risk premium estimates and systematic risk estimates. Moreover, we find that the *ex ante* risk premium estimates for

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broad industry groups have a high correlation with the corresponding Fama-French (1997) estimates from the CAPM, but not with the estimates from their three-factor model.

The study's practical implications are based on the widespread use of the CAPM in cost of capital estimation by large US firms and investors, where the traditional use of the S&P 500 index as the "market portfolio" continues to be the standard. Our findings support the use of the domestic CAPM to estimate the cost of equity of large US firms. However, finding a relatively small difference in the overall fit of the two CAPM versions suggests that the choice between applying the domestic CAPM and the global CAPM may not be a critical issue for many large US firms.

The paper is organized as follows. Section I reviews related literature. This review includes the domestic and global versions of the single-factor CAPM and why the two models are theoretically likely to result in different expected rates of return for a given asset. Section II discusses the methodology and data for the empirical analysis. Section III reports the results of the empirical comparison of the *ex ante* expected return estimates with the estimates of the two CAPM versions and with corresponding measures of risk. Section IV provides a brief summary and conclusion.

I. Review of Related Literature

Recent survey evidence (Bruner, Eades, Harris, and Higgins, 1998) and Graham and Harvey, 2001) reports that the capital asset pricing model (CAPM) is widely used by large US firms and investors. The CAPM also continues to have wide popularity in academic textbooks and applied articles (e.g., Kaplan and Peterson, 1998 and Ruback, 2002).

These applications use the traditional domestic CAPM, $k_i = r_f + \beta_{iD}[k_{MD} - r_f]$; where k_i is the equilibrium expected rate of return for asset i; r_f is the risk-free rate; β_{iD} is the beta of asset i against the domestic market portfolio returns; k_{MD} is the equilibrium required rate of return on the domestic market portfolio; and $k_{MD} - r_f$ is the risk premium on the domestic market portfolio.

A. Global CAPM and Domestic CAPM

Stehle (1977) and Stulz (1995a, 1995b, 1999) argue that using a domestic market index is only appropriate for an asset traded in a closed, national financial market. Although equilibrium international asset pricing models are multifactor in general, if the purchasing power parity (PPP) condition holds, then the single-factor CAPM equation can be adapted to a international context for assets in the global market portfolio, as discussed in Stulz (1995c). We emphasize the difference between the domestic and global CAPMs by Equation (1).

$$k_i = r_f + \beta_{iG}[k_{MG} - r_f] \qquad (1)$$

where k_i is the equilibrium expected rate of return for asset i in a specific pricing currency, r_f is the nominal rate of return on an asset that is risk-free and denominated in the pricing currency, β_{iG} is the beta of asset i's returns against the unhedged global market index returns, with returns computed in the pricing currency, k_{MG} is the equilibrium required rate of return in the pricing currency on the unhedged global market portfolio, and $k_{MG} - r_f$ is the risk premium on the unhedged global market portfolio. As in Grauer, Litzenberger, and Stehle (1976), under the assumption of logarithmic utility the global CAPM in Equation (1) holds

with any numeraire currency. Ross and Walsh (1983) show that when log utility is not assumed, Equation (1) holds for at most one currency. We assume that currency is the US dollar.

Karolyi and Stulz (2003) point out that only in the special case in which β_{iG} equals $\beta_{iD}\beta_{DG}$ does the global CAPM result in the same expected return as the domestic CAPM, i.e., when an asset's global beta is equal to its domestic beta times the global beta of the domestic market portfolio. Generally, this condition does not hold. Instead, when β_{iG} is greater than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to underestimate the asset's expected return relative to the global CAPM, because there is more global systematic risk in the asset's returns than is accounted for by the domestic market index. Similarly, when β_{iG} is less than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to overestimate the asset's expected return relative to the global CAPM, because the asset has less global systematic risk in its returns than is accounted for by the domestic market index.

Stehle (1977) reports empirical support for the global CAPM over the domestic version in realized returns for US stocks from 1956 to 1975. Harvey's (1991) study provides further empirical support of global pricing of US equities. Black (1993) asserts that the issue of whether a global or domestic index should be used in CAPM applications is not yet settled. However, given the significant globalization of the world financial markets, Stulz (1995a, 1995b, 1999) advocates the use of the global version. In contrast to Stehle's (1977) findings, Griffin (2002) reports that for the period between 1981 and 1995, a three-factor (Fama-French) domestic model had lower pricing errors for US firms than did an analogous three-factor world version. His results indicate that a domestic pricing model is a better fit with realized return data than a global pricing model.

Campbell's (1996) empirical analysis of a multifactor domestic pricing model finds that the single-factor domestic "... CAPM is a good approximate model for stock and bond prices," since the additional factors (returns to human capital and changes in expected market return) are highly correlated with the market index returns. Ng (2003) reaches a similar conclusion in the context of the global CAPM, with the additional factors of FX risk and shifts in both expected market returns and expected FX changes. Therefore, we only examine the two single-factor CAPMs. Griffin (2002) does not report results on domestic compared to world single-factor (market index) models. However, in private correspondence after our study was completed, Griffin reported to us that the domestic version of the single-factor model had lower pricing errors than did the world model.

For large US companies like those in the S&P 500, there are arguments why choosing a domestic or a global index for CAPM applications could be a non-issue. One argument is that a US index will closely track a global index, especially as markets have become more integrated and since the market value of US stocks is a substantial proportion of the market value of a global index. However, the data show that the beta of the S&P 500 compared to the MSCI World Index has been substantially less than one in the past. Another argument is that S&P 500 companies are often global in scope, which makes the S&P 500 something of a global index in its own right. However, Jacquillat and Solnik (1978) and Christophe and McEnally (2000) report evidence that a portfolio of US multinationals is an ineffective vehicle for international diversification. Even if the choice between a global and a domestic index does not matter much for large US firms in general, it might make a difference for US firms with very high (or low) levels of foreign involvement. However, this empirical question is unanswered. Older studies by Hughes, Logue, and Sweeney (1975) and Agmon and Lessard (1977) suggest this possibility, reporting that global (domestic) betas increased (decreased) with the level of US firms' foreign-to-total sales ratio. However, more recent results in Diermeier and Solnik (2001) do not find this effect to be strong for US firms.

A domestic index could be the preferred benchmark for US investors with a significant "home bias", as in the Cooper and Kaplanis (2000) model of partially integrated world markets. However, we do not know whether the popularity of the domestic CAPM among US firms is for this reason.

B. *Ex Ante* Expected Return Estimates

Empirical tests comparing global to domestic pricing models usually rely on realized returns. However, Elton (1999) points out that *ex ante* estimates of expected returns are more desirable. We obtain *ex ante* expected return estimates through analysts' growth forecasts and discounted cash flow (DCF) models, as in a number of prior studies, including Claus and Thomas (2001), Fama and French (2002), and others discussed below.

In contrast to research that uses realized returns, almost all of the studies using *ex ante* expected return estimates find an empirical relation between expected return and beta risk, despite differences in approaches and time periods. For example, using the constant dividend growth model, Harris and Marston (1992) and Marston and Harris (1993) report a significant relation between *ex ante* expected return estimates and (domestic) betas for a sample of US stocks in the 1982-1987 period. At the same time they confirm the findings of previous empirical studies of no significant relation between realized returns and betas.

When they apply a DCF model to 51 highly leveraged transactions (mostly management buyouts) in the period 1980-1989, Kaplan and Ruback (1995) find that implied costs of capital estimates are related to beta but not to the size and book-to-market factors. Using IBES forecasts, Gordon and Gordon (1997) and Gode and Mohanram (2003) also observe a significant relation between *ex ante* expected equity return estimates and domestic US betas. Gordon and Gordon use a finite horizon dividend discount model and the time period 1985-1991. Gode and Mohanram use the Ohlson-Juettner (2000) valuation model for the period 1984-1998. Also, Brav, Lehavy, and Michaely (2003) find a positive empirical association between analysts' direct return forecasts and beta for US stocks, but not between the return forecasts and the size and book-to-market factors.

The results of Gebhardt, Lee, and Swaminathan (2001) provide the only exception that we know of to a positive empirical relation between *ex ante* expected return and beta risk estimates. Their study, which uses IBES forecasts and a clean-surplus residual income valuation model, reports no significant association between their *ex ante* expected return estimates and domestic betas for a sample of US stocks from the period 1979-1995.

There is some controversy about IBES forecasts. La Porta (1996) asserts that analysts' growth forecasts tend to be too extreme, but Lee, Myers, and Swaminathan (1999) find that IBES forecasts improve their intrinsic value estimates over forecasts based on a time series model.

II. Methodology and Data

In this section, we discuss our approach for estimating *ex ante* expected returns using the constant dividend growth model and the consensus of financial analysts' five-year earnings growth forecasts available through IBES. In addition, we explain our criteria for comparing the global and domestic CAPMs.

A. *Ex Ante* Expected Return Estimation

For each month from January 1983 through August 1998, we calculate an *ex ante* expected

return estimate for each dividend-paying US stock in the S&P 500 index for which data are available. We eliminate a firm in a given month if there are fewer than three analysts' forecasts, if the standard deviation around the mean forecast exceeds 20%, or if there are not sufficient historical returns for the prior 60 months to perform beta estimations. The analysis comprises 65,154 expected return estimates for the months from January 1983 to August 1998. We obtain dividend and other firm-specific information from the Compustat files.

We estimate *ex ante* expected rates of return by using the constant dividend growth model.

$$k_i^a = \frac{D_{1i}}{P_{0i}} + g_i \qquad (2)$$

where k_i^a is the *ex ante* expected rate of return (cost of equity) estimate for company i, D_{1i} is the dividend per share expected to be received at time 1, P_{0i} is the current price per share, and g_i the expected long term growth rate in dividends per share, which we assume is equal to the consensus of the analysts' growth forecasts. See Timme and Eisemann (1989) for a review of the benefits of analysts' forecasts over historical growth estimates.

We recognize that our study, like any study of asset pricing relations, is a joint "test" of the underlying model and the empirical constructs used. Therefore, like other studies, we cannot conclude whether rejection is due to failure of the model or of the empirical proxies. With this standard caveat, our method for estimating *ex ante* expected returns, which uses IBES growth forecasts and the dividend growth model, has several strengths. First and foremost, theory suggests that measures of return should be those that investors expect to prevail over some future time horizon. Although many empirical tests rely on realized returns, there is no necessary relation between the investors' expected returns suggested by theory and subsequently realized returns, except under strong assumptions.

Second, as noted earlier, and in contrast to studies that use realized returns, the results of studies that use *ex ante* expected return estimates are robust across time periods and DCF models in finding a positive empirical relation between expected return and systematic risk. Since we find that our *ex ante* expected return estimates behave similarly to those of other empirical studies, we believe that our *ex ante* estimates are representative.

Third, our approach should not bias the outcome of this study toward one version of the CAPM over the other. That is, there is no reason to think that the relative fit of the two CAPM versions with the *ex ante* expected return estimates depends on a particular DCF valuation model or source of growth forecasts.

Finally, given the widespread use of the CAPM, the conflicting empirical results on the impact of using a domestic or global index warrants additional study using a variety of approaches. Furthermore, additional empirical results on the constant growth model, given its longstanding history and continued use, could be useful.

B. Global CAPM Compared to Domestic CAPM

To use either the global or the domestic CAPM to estimate a firm's cost of equity, we use a time-varying approach to estimate betas and market risk premia. We estimate the firms' equity betas for a particular month with monthly excess returns (the stock return minus 20-year Treasury bond (T-bond) return) for five years prior to the month for which we estimate the cost of equity. We estimate equity betas for all companies by using an ordinary least squares (OLS) of excess stock returns on excess market index returns. We obtain monthly stock

returns in US dollars from January 1978 through August 1998 from the CRSP files. We obtain T-bond returns from the website of the Federal Reserve Bank of St. Louis. We use the S&P 500 Index as the domestic US index. (We also use the CRSP Value-Weighted Index in a robustness check.) We use the Morgan Stanley Capital International (MSCI) World Index with gross dividend reinvestment as the global market index. The monthly data for the global index is from the website of MSCI: www.mscidata.com. This index is unhedged and thus, when reported in US dollars, reflects exchange rate changes in currencies against the US dollar.

The question we investigate is which of the two CAPM versions, if we assume that version is the "correct" model, has less variation in its fit with the *ex ante* expected return estimates for the individual firms. To implement this investigation, we "back out" the estimated *market* risk premia (domestic and global) for each month from the *ex ante* expected returns of the individual stocks. To do so, for a given month, we first turn each stock's *ex ante* expected return estimate into an *ex ante* risk premium estimate by subtracting the yield on the 20-year T-bond. Then we aggregate the stocks' *ex ante* risk premia estimates with value weighting, producing an *ex ante* portfolio risk premium estimate for the month. For the domestic CAPM, we value-weight the firms' domestic beta estimates into a portfolio domestic beta estimate for the month. Since the portfolio risk premium should be equal to the portfolio beta times the market risk premium, the domestic market risk premium estimate for the month is found implicitly by dividing the portfolio risk premium estimate by the portfolio domestic beta estimate. For example, if the value-weighted portfolio of eligible stocks has an *ex ante* risk premium estimate of 6% and a domestic beta estimate of 0.9, then the implicit domestic market risk premium estimate (for that month) is 6% divided by 0.9, which equals 6.67%. To ensure a fair comparison between the domestic CAPM (DCAPM) and the global CAPM (GCAPM), we use an analogous procedure (each month) to estimate the implicit global market risk premium from the *ex ante* portfolio risk premium estimate and the portfolio's global beta estimate. In other words, we estimate the domestic market risk premium by assuming that the domestic CAPM is valid for the average stock, and estimate the global market risk premium by assuming that the global CAPM is valid for the average stock. By design, this approach implies that the average difference between the model estimates and the *ex ante* estimates is zero for both CAPM versions.

We then investigate how much variation exists for individual firms between the *ex ante* risk premium estimates and the corresponding estimates of each of the two CAPM versions. For each month from January 1983 until August 1998, we analyze each available stock as follows. We begin by using the stock's domestic beta and the domestic market risk premium estimates to find the firm's risk premium estimate under the DCAPM. We also estimate the stock's risk premium under the GCAPM with the stock's global beta and the global market risk premium estimates. We then compare the *ex ante* risk premium estimate for the stock with the risk premium estimates of both CAPM versions.

For a given stock and month, there will generally be differences between all three risk premium estimates. For example, a stock in June 1989 might have an *ex ante* risk premium estimate of 5%, a DCAPM estimate of 4%, and a GCAPM estimate of 7%. In this hypothetical example, the DCAPM would be considered as the better fit because it provides a risk premium estimate that is closer to the *ex ante* estimate.

We use three metrics to assess which of the two CAPM versions has the better overall fit with the *ex ante* estimates. First, we examine the average of the absolute differences between the model estimates and the *ex ante* estimates. We decide that the model with the lower overall average of absolute differences across all observations for the individual firms is the better-fitting model for this metric. Second, we determine the percentage of the *ex ante*

estimates for which the DCAPM provides a closer fit than the GCAPM. In the third metric, we compare the results of cross-sectional OLS of *ex ante* risk premium estimates for the individual stocks against both the estimated domestic betas and the estimated global betas. Whichever regression has the higher r-squared indicates the better-fitting CAPM version with this approach. We also examine the regression results for relative consistency with the theory: an intercept of zero and a positive slope.

Further, we investigate whether the fit of the *ex ante* estimates with those of the two CAPM versions is related to the ratio of foreign sales to total sales, which we use here as a proxy for international exposure. Although we understand that the relative level of foreign sales does not completely capture a firm's international exposure, its use is standard in many empirical studies, including Fatemi (1984), Jorion (1990), Miller and Reuer (1998), and Doidge, Griffin, and Williamson (2002), who contend that a good rationale for using relative foreign sales as a proxy for international exposure is the high correlation with other measures of firms' international operations.

Of the 489 firms used in the study, 253 firms have a reported foreign sales entry (including 76 firms reporting zero foreign sales) for the period 1994 to 1998. The overall average ratio of foreign to total sales is approximately 20% for the 253 firms. Using the eligibility criteria discussed above, we use the data for the 253 firms from 1983 to 1998 to construct a subsample of 36,580 observations (out of the 65,154 total observations), an average of about 194 firms per month. Of these observations, 11,053 involve a firm reporting zero foreign sales during 1994-1998, an average of about 59 firms per month. We divide the remaining observations, involving firms reporting non-zero foreign sales during 1994-1998, into three equal-sized groups of 8,509 observations based on the magnitude of relative foreign sales. Each group had an average of about 45 firms per month. The high foreign sales group has an average ratio of foreign to total sales of 53%, and the medium and low groups had ratios of 27% and 7%, respectively.

III. Results

This section describes in detail the results of the study, as reported in the tables.

A. Summary of Risk Premium Differences for DCAPM and GCAPM

Table I summarizes the average absolute differences between the *ex ante* risk premium estimates and the DCAPM and GCAPM estimates, and the percentage of instances in which the *ex ante* estimates are closer to the DCAPM estimate than to the GCAPM estimate. For all the observations in the sample, over all years from 1983 through 1998, the DCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.027, or 270 basis points. The GCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.029, or 290 basis points.

For every year except 1992, the average absolute difference between the DCAPM estimates and the *ex ante* estimates is less than or equal to the average absolute difference between the GCAPM estimates and the *ex ante* estimates. Based on the average absolute difference criterion, we find that the DCAPM has a better overall fit with the *ex ante* risk premium estimates.

However, the overall margin of difference, 270 basis points compared to 290 basis points, is not dramatic. The difference is the closest in the early 1990s. In contrast, in the 1980s and late 1990s, the DCAPM is the better fit by a wider margin. In a robustness check, we obtain

Table I. Summary of Risk Premium Differences For DCAPM and GCAPM

The columns show, respectively, the average number of firms per month (#Firms), the value-weighted averages of the estimated *ex ante* risk premia (*Ex Ante*), average domestic beta estimates (β_{iD}), the average domestic market risk premium estimates (RP_D), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average global beta estimates (β_{iG}), the average global market risk premium estimates (RP_G), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

Year	#Firms	*Ex Ante*	β_{iD}	RP_D	*Ex*-D	β_{iG}	RP_G	*Ex*-G	%DCAPM Closer
1983	285	0.066	0.883	0.075	0.030	0.864	0.077	0.031	0.573(8.489)***
1984	300	0.053	0.915	0.058	0.026	0.897	0.059	0.027	0.581(9.777)***
1985	314	0.057	0.925	0.062	0.026	0.915	0.062	0.028	0.561(7.524)***
1986	320	0.074	0.985	0.075	0.028	0.890	0.084	0.030	0.580(9.931)***
1987	327	0.061	1.024	0.060	0.024	0.941	0.065	0.027	0.618(14.76)***
1988	335	0.064	1.000	0.064	0.024	0.969	0.066	0.026	0.589(11.28)***
1989	352	0.066	0.982	0.067	0.023	0.890	0.073	0.025	0.601(13.08)***
1990	357	0.071	0.972	0.073	0.025	0.797	0.089	0.026	0.531(4.108)***
1991	363	0.075	0.976	0.077	0.027	0.723	0.104	0.027	0.482(-2.409)**
1992	370	0.078	0.990	0.079	0.030	0.723	0.109	0.028	0.440(-8.002)***
1993	374	0.082	1.018	0.080	0.029	0.576	0.142	0.029	0.490(-1.299)
1994	375	0.073	1.038	0.070	0.025	0.576	0.126	0.026	0.515(2.012)**
1995	370	0.077	1.039	0.074	0.028	0.579	0.133	0.031	0.538(5.118)***
1996	379	0.078	1.008	0.077	0.027	0.604	0.129	0.035	0.632(17.83)***
1997	383	0.082	1.005	0.081	0.029	0.650	0.127	0.037	0.616(15.73)***
1998	388	0.092	1.010	0.091	0.031	0.793	0.116	0.035	0.575(7.826)***
Avg.	349	0.072	0.986	0.073	0.027	0.774	0.097	0.029	0.556(28.57)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.

similar results (not reported here) when we use the CRSP Value-Weighted Index instead of the S&P 500 Index for the domestic US market portfolio.

We make two observations about the magnitudes of the market risk premium estimates. First, the global market risk premium estimates are higher than the local US market risk premium estimates. Although this observation may seem counterintuitive, it is a logical consequence of the fact that the global beta of the US market has historically been less than one. (See, for example, Karolyi and Stulz, 2003). Our second observation is that market risk premium estimates are higher than those reported in studies by Claus and Thomas (2001) and Fama and French (2002), but have a similar magnitude to that observed by Kaplan and Ruback (1995) and to the long-term unconditional estimates of Constantinides (2002). Regardless, these estimates should not bias the results in favor of one CAPM version over the other.

When we examine the percentage analysis reported in Table I, we see that with the exception of the three consecutive years from 1991 through 1993, in the majority of the cases the *ex ante* risk premium estimate is closer to the DCAPM estimate than to the GCAPM estimate. Overall, the *ex ante* estimates are closer to the DCAPM estimate 56% of the time. Given the large sample, this percentage is significant in a statistical sense.

B. Cross-Section Regressions On Systematic Risk

Table II reports the results of the cross-section regression of the firms' *ex ante* risk premium estimates on the beta estimates. Overall, the cross-section regressions provide further evidence that consistently throughout the time period 1983-1998, the *ex ante* estimates have a better fit with those of the DCAPM than with the GCAPM. Table II shows that the r-squares of all of the regressions are higher when we use the domestic beta as the independent variable than with the global beta. Moreover, the DCAPM regression results are consistently better aligned with the theory. The regression intercepts are closer to zero for the DCAPM than for the GCAPM, and the *t*-statistics on the slope coefficients are more significant for the DCAPM than for the GCAPM. These observations apply to the entire period, to all four individual sub-periods, and to each of the 16 years covered in the study.

The findings of significant, positive slope coefficients in each of the 16 years' cross-section regressions appear to strongly confirm the basic asset pricing theory prediction that expected returns are positively related to beta risk. We note that we are using individual stock parameters, not portfolios, and we use no control variables in the cross-section regressions. However, the positive regression intercepts suggest the possible omission of risk factor(s) or systematic optimism in the analysts' growth forecasts. Further exploration of this issue is beyond the scope of this study and is a topic for future research.

Together, Tables I and II lead us to conclude that using all three metrics (average absolute differences, percentage of cases with the better fit, and cross-section regression results), the domestic CAPM fits the dispersion of *ex ante* risk premium estimates better than does the global CAPM. This finding surprised us, in light of the continuing integration of world financial markets and international diversification by investors. However, this finding is consistent with the Cooper and Kaplanis (2000) model of partially segmented global capital markets and home bias.

C. Impact of Foreign Sales

We hypothesize that the global CAPM provides the better fit for companies with a relatively higher level of foreign sales, or that at least we observe a trend toward this relation over time. Table III shows this expectation is not the case. Only in the 1990-1994 period the GCAPM is the better fit for the high and medium foreign sales groups, and the DCAPM is the better fit for the low and zero foreign sales groups. However, after 1994, the pattern is generally the same for all four foreign sales groups, and there is no longer a better fit by the GCAPM for firms in the high and medium relative foreign sales groups.

Looking at all the years together, the average absolute differences between the *ex ante* risk premium estimates for the individual stocks and those of the two CAPM versions are about the same for each foreign sales level group, and the DCAPM estimates are slightly closer to the *ex ante* estimates in all four groups. Thus, we conclude that the relative level of foreign sales does not indicate when the *ex ante* expected returns are more closely related to the GCAPM than the DCAPM, except possibly during times when the US and global economies are not in sync.

D. Risk Premium Estimates and Differences by Industry

Given the potential for measurement error at the company level, there are benefits from looking at industry aggregates. Table IV breaks down the full-period risk premium estimates by broad industry groups. The results weight each firm in the industry equally. We obtain similar results

Table II. Cross-Section Regressions

The table presents the results of cross-section regressions of *ex ante* risk premium estimates and systematic risk estimates for individual firms. We use ordinary least squares, with *ex ante* risk premium estimates as the dependent variable and firm beta against indicated market portfolio as independent variable. The numbers in parenthesis are the corresponding *t*-statistics.

	Versus Domestic Beta			Versus Global Beta			
Year	Intercept	Slope	R-Sq	Intercept	Slope	R-Sq	#Obs
1998	0.062 (35.07)***	0.025 (13.73)***	0.065	0.065 (38.39)***	0.025 (12.45)***	0.054	2718
1997	0.059 (46.08)***	0.020 (15.45)***	0.050	0.067 (62.89)***	0.026 (10.99)***	0.026	4590
1996	0.053 (43.91)***	0.023 (19.79)***	0.079	0.063 (65.33)***	0.021 (14.87)***	0.046	4544
1995	0.053 (45.99)***	0.020 (20.74)***	0.088	0.059 (57.29)***	0.027 (17.04)***	0.061	4439
1994	0.043 (35.78)***	0.026 (25.85)***	0.129	0.05 (40.52)***	0.037 (18.69)***	0.072	4503
1993	0.048 (38.14)***	0.028 (25.43)***	0.126	0.056 (44.79)***	0.039 (18.99)***	0.074	4489
1992	0.041 (27.73)***	0.027 (20.57)***	0.087	0.042 (28.77)***	0.037 (20.38)***	0.086	4437
1991	0.036 (22.29)***	0.031 (21.99)***	0.100	0.043 (27.05)***	0.034 (17.61)***	0.067	4357
1990	0.035 (20.00)***	0.033 (20.86)***	0.092	0.047 (28.44)***	0.026 (13.99)***	0.044	4287
1989	0.039 (25.59)***	0.025 (17.87)***	0.070	0.049 (35.32)***	0.017 (11.97)***	0.038	4222
1988	0.039 (24.17)***	0.023 (15.60)***	0.057	0.048 (31.53)***	0.016 (11.29)***	0.031	4015
1987	0.037 (23.05)***	0.024 (16.90)***	0.068	0.048 (32.75)***	0.016 (10.88)**	0.029	3929
1986	0.057 (42.63)***	0.017 (14.19)***	0.050	0.065 (49.90)***	0.011 (8.33)***	0.018	3835
1985	0.045 (40.69)***	0.012 (12.06)***	0.037	0.051 (45.47)***	0.007 (6.96)***	0.013	3770
1984	0.045 (38.79)***	0.008 (7.27)***	0.015	0.05 (43.15)***	0.003 (2.67)***	0.002	3605
1983	0.053 (45.93)***	0.011 (10.23)***	0.030	0.057 (50.04)***	0.007 (6.87)***	0.014	3414
1995-1998	0.058 (88.77)***	0.020 (32.61)***	0.061	0.063 (113.76)***	0.023 (29.25)***	0.050	16,291
1991-1994	0.042 (61.55)***	0.028 (46.34)**	0.108	0.054 (82.29)***	0.027 (29.93)***	0.048	17,786
1987-1990	0.038 (46.83)***	0.026 (35.09)***	0.070	0.051 (68.49)***	0.016 (21.31)***	0.027	16,453
1983-1986	0.049 (79.50)***	0.013 (22.82)***	0.034	0.057 (92.38)***	0.006 (10.27)***	0.007	14,624
1983-1998	0.049 (138.64)***	0.020 (64.27)***	0.059	0.065 (215.79)***	0.006 (18.81)***	0.005	65,154

***Significant at the 0.01 level.

Table III. Impact of Foreign Sales

The table displays the results of our analysis of the average absolute risk premium differences for individual firms for four groups, sorted by the ratio of foreign sales to total sales. The average ratio of foreign-to-total sales for the HIGH (MEDIUM, LOW) Foreign Sales Group is 53% (28%, 7%), respectively. Each group shows three columns, the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

	High Foreign Sales			Medium Foreign Sales		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.025	0.029	0.707(9.76)***	0.029	0.031	0.585(3.73)***
1984	0.021	0.024	0.723(10.69)***	0.027	0.028	0.620(5.36)***
1985	0.021	0.023	0.571(3.14)***	0.027	0.027	0.513(0.58)
1986	0.023	0.026	0.613(5.14)***	0.028	0.029	0.517(0.72)
1987	0.021	0.022	0.605(4.75)***	0.027	0.029	0.574(3.47)***
1988	0.023	0.024	0.561(2.76)***	0.027	0.028	0.560(2.84)***
1989	0.023	0.024	0.571(3.30)***	0.026	0.028	0.555(2.65)***
1990	0.024	0.024	0.476(-1.12)	0.028	0.027	0.519(0.89)
1991	0.031	0.030	0.443(-2.71)***	0.028	0.028	0.549(2.33)**
1992	0.029	0.026	0.353(-7.38)***	0.029	0.029	0.487(-0.62)
1993	0.028	0.024	0.405(-4.74)***	0.032	0.030	0.525(1.22)
1994	0.024	0.020	0.409(-4.55)***	0.027	0.024	0.499(-0.04)
1995	0.027	0.028	0.464(-1.79)*	0.026	0.029	0.544(2.058)**
1996	0.022	0.032	0.664(8.50)***	0.025	0.040	0.702(10.42)***
1997	0.025	0.037	0.664(8.57)***	0.025	0.047	0.788(16.91)***
1998	0.026	0.034	0.627(5.28)***	0.029	0.041	0.749(11.44)***
Average	0.025	0.027	0.546(8.55)***	0.028	0.031	0.578(14.51)***
	Low Foreign Sales			Zero Foreign Sales		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.036	0.036	0.499(-0.04)	0.027	0.029	0.518(0.88)
1984	0.029	0.028	0.530(1.27)	0.025	0.026	0.54(2.01)**
1985	0.028	0.030	0.639(6.31)***	0.029	0.031	0.585(4.48)***
1986	0.032	0.032	0.532(1.41)	0.028	0.032	0.649(8.11)***
1987	0.027	0.027	0.579(3.59)***	0.026	0.031	0.682(10.27)***
1988	0.025	0.026	0.511(0.49)	0.024	0.027	0.611(6.01)***
1989	0.026	0.027	0.579(3.82)***	0.022	0.024	0.579(4.19)***
1990	0.027	0.028	0.559(2.80)***	0.026	0.027	0.482(-0.97)
1991	0.025	0.027	0.533(1.59)	0.026	0.025	0.414(-4.66)***
1992	0.029	0.030	0.526(1.24)	0.026	0.025	0.484(-0.85)
1993	0.030	0.031	0.542(2.04)**	0.026	0.032	0.551(2.80)***
1994	0.025	0.024	0.503(0.17)	0.024	0.029	0.57(3.92)***
1995	0.026	0.027	0.506(0.29)	0.031	0.036	0.634(7.55)***
1996	0.026	0.027	0.554(2.66)***	0.033	0.040	0.611(6.19)***
1997	0.027	0.031	0.557(2.80)***	0.034	0.038	0.534(1.89)*
1998	0.030	0.032	0.512(0.49)	0.033	0.033	0.526(1.22)
Average	0.028	0.029	0.541(7.67)***	0.027	0.030	0.561(12.99)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

Table IV. Risk Premium Estimates and Differences by Industry

The table shows the breakdown of the full-period risk premium estimates by broad industry groups. The reported results weight each firm in the industry equally. Columns two to nine, respectively, show the total number observations (#Obs), the average *ex ante* risk premia (*Ex Ante*), the average domestic beta estimates (β_{iD}), the average global beta estimates (β_{iG}), the average DCAPM industry risk premium estimate (RP_D), the average GCAPM industry risk premium estimate (RP_G), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), and the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are the corresponding *t*-statistics. Rows in italics indicate *Ex*-G lower than *Ex*-D.

Industry	#Obs	*Ex Ante*	β_{iD}	β_{iG}	RP_D	RP_G	*Ex*-D	*Ex*-G	%DCAPM Closer
Aero	738	6.63	1.15	0.90	7.86	7.97	0.031	0.033	0.52(0.96)
Autos	1546	5.29	1.15	0.89	7.94	7.69	0.033	0.037	0.54(3.52)***
Banks	4004	7.16	1.21	0.85	8.58	7.96	0.027	0.026	0.49(-0.82)
Beer	1264	6.60	0.87	0.69	6.07	6.25	0.024	0.028	0.64(10.25)***
BldMt	1298	6.84	1.27	1.01	8.74	8.51	0.026	0.029	0.64(10.84)***
Books	1291	7.64	1.07	0.80	7.37	6.86	0.021	0.023	0.52(1.48)
Boxes	626	8.39	1.04	0.85	7.15	7.27	0.027	0.029	0.52(1.04)
BusSv	1374	8.15	1.07	0.82	7.49	7.24	0.023	0.028	0.60(7.77)***
Chems	2451	6.49	1.16	0.94	7.99	8.14	0.024	0.026	0.57(7.50)***
Chips	1414	8.11	1.28	0.96	8.93	8.53	0.026	0.028	0.57(5.70)***
Clths	562	7.74	1.37	0.93	9.69	8.74	0.030	0.030	0.47(-1.44)
Cnstr	*989*	*7.70*	*1.54*	*1.18*	*10.68*	*10.33*	*0.046*	*0.039*	*0.39(-7.14)****
Comps	*1281*	*9.42*	*1.19*	*0.90*	*8.31*	*8.09*	*0.032*	*0.037*	*0.53(2.27)***
Drugs	2098	8.29	0.99	0.78	6.91	7.09	0.023	0.023	0.50(0.00)
ElcEq	1246	6.89	1.08	0.89	7.46	7.63	0.017	0.019	0.55(3.65)***
Energy	3487	6.29	0.88	0.87	5.99	7.63	0.032	0.035	0.57(8.12)***
Fin	657	8.38	1.76	1.13	12.87	11.89	0.056	0.053	0.49(-0.74)
Food	*2588*	*7.02*	*0.86*	*0.65*	*5.99*	*5.77*	*0.019*	*0.025*	*0.69(20.71)****
Fun	183	9.98	1.19	0.95	8.25	8.40	0.020	0.018	0.33(-4.78)***
Gold	588	4.59	0.57	0.85	3.76	7.48	0.050	0.051	0.61(5.50)***
Hlth	432	10.4	1.29	1.05	8.99	9.83	0.026	0.024	0.49(-0.48)
Hshld	2368	6.77	1.02	0.77	7.10	6.92	0.021	0.022	0.51(1.11)
Insur	4992	7.46	1.03	0.72	7.23	6.45	0.024	0.024	0.51(1.95)*
LabEq	1280	7.31	1.10	0.92	7.48	7.92	0.020	0.020	0.48(-1.40)
Mach	*2683*	*7.32*	*1.20*	*0.98*	*8.36*	*8.86*	*0.027*	*0.032*	*0.57(7.75)****
Meals	561	7.98	1.06	0.79	7.35	7.18	0.024	0.028	0.63(6.53)***
MedEq	1334	8.80	1.03	0.77	7.18	6.86	0.029	0.032	0.52(1.70)*
Paper	2969	6.14	1.13	0.89	7.79	7.59	0.024	0.025	0.59(9.48)***
PerSv	453	9.12	0.95	0.76	6.61	6.95	0.028	0.028	0.58(3.28)***
Retail	*4380*	*9.27*	*1.12*	*0.76*	*7.74*	*6.65*	*0.031*	*0.038*	*0.62(16.24)****
Rubber	524	7.06	1.22	0.88	8.55	8.14	0.025	0.027	0.55(2.19)**
Ships	187	1.95	0.95	0.65	6.39	4.75	0.046	0.041	0.27(-6.98)***
Stee	1510	4.96	1.13	0.97	7.76	8.18	0.041	0.044	0.61(8.92)***
Telcm	1553	6.12	0.83	0.61	5.91	6.08	0.020	0.023	0.56(4.42)***
Toys	*447*	*7.42*	*1.24*	*0.93*	*8.70*	*8.54*	*0.028*	*0.035*	*0.69(8.63)****
Trans	1651	5.70	1.14	0.87	7.90	7.67	0.029	0.031	0.50(0.37)
Txtls	374	6.52	0.95	0.74	6.50	6.53	0.022	0.024	0.58(3.14)***
Util	6189	4.15	0.57	0.48	3.95	4.38	0.017	0.019	0.57(10.79)***
Whlsl	1582	8.29	0.92	0.75	6.41	6.77	0.028	0.025	0.45(-4.40)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

with value weighting. Also, the DCAPM industry risk premium estimates with the CRSP Value-Weighted Index are very close to the estimates we report for the S&P 500 Index.

Since the DCAPM provides the better overall fit, the DCAPM will have the better fit for many industries. The GCAPM provides a slightly better fit for a few of the industry groups, Banks, Construction, Finance, Health, and Wholesale. For industry groups such as Computers, Food, Machines, Retail, and Toys, the DCAPM provides a significantly better overall fit with the *ex ante* estimates than does the GCAPM.

E. Further Analysis of Industry Risk Premium Estimates

Table V reports the results of cross-section regressions using the industry risk premium estimates for the period 1983-1998, and estimates obtained from other approaches by Fama and French (1997) and Gebhardt et al. (2001). We excluded the Ships and Fun industries, which only had one firm each in our sample.

The most striking result in Table V is that the *ex ante* industry risk premium estimates have an r-square of 31.6% (a correlation of about 0.56) with the Fama-French DCAPM estimates. The Fama-French DCAPM industry estimates even outperform our own DCAPM industry estimates in explaining our *ex ante* industry estimates, even though the Fama-French time span is different, 1963-1994. Perhaps the explanation has to do with investors using more than five years of realized returns as the basis for expectations, or viewing the one-month Treasury bill (used by Fama and French) as the risk-free security instead of the 20-year T-bond used in this study. Both of the DCAPM industry estimates outperform the GCAPM industry estimates.

The r-square of the *ex ante* industry risk premium estimates and the Fama-French (1997) industry risk premium estimates for the 3-Factor Model is only 5.79% (a correlation coefficient of 0.24). Thus, the *ex ante* industry risk premium estimates have a much better fit with the Fama-French DCAPM industry estimates than with those of the 3-Factor Model. This finding is consistent with similar findings reported by Kaplan and Ruback (1995) and Brav et al. (2003). The results with the CRSP Value-Weighted Index as the DCAPM benchmark are very close to those reported with the S&P 500 Index.

Gebhardt et al. (2001) determined their *ex ante* risk premium estimates by using the residual income model from the full period 1979-1995, with the ten-year T-bond serving as the risk-free security. The Gebhardt-Lee-Swaminathan industry risk premium estimates have a very low correlation with our DCAPM and GCAPM estimates, with the Fama-French (1997) DCAPM and 3-Factor Model estimates, and with our *ex ante* industry estimates.

IV. Conclusion

We compare *ex ante* expected return estimates, which are implicit in share prices, analysts' growth forecasts, and the dividend growth model, with expected return estimates from the global CAPM and the domestic (US) CAPM. We use the MSCI World Index as the market benchmark for computing betas for the global CAPM, and both the S&P 500 Index and the CRSP Value-Weighted Index as the market benchmark for computing betas for the domestic CAPM. Our sample comprises S&P 500 companies over the period 1983-1998. We find that the domestic CAPM has a better fit with the dispersion of *ex ante* expected return estimates, overall and for all subsamples, based on the ratio of foreign sales to total sales. We observe no trend in this fit over time. While the domestic model provides a better fit of our data, the relatively small empirical difference between the models suggests that for estimating the

Table V. Cross-Section Regressions with Industry Risk Premium Estimates

Panel A displays the results of cross-section regressions. We use our industry *ex ante* risk premium estimates for the period 1983-1998 compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997) and Gebhardt, Lee, and Swaminathan (2001). Panel B shows the results of cross-section regressions using the Gebhardt, Lee, and Swaminathan (2001) *ex ante* risk premium estimates (from the residual income model for the overall time period 1979-1995) compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997). The numbers in parenthesis are the corresponding *t*-statistics.

Panel A. Dependent Variable: Ex Ante Industry Risk Premium Estimate			
Independent Variable	**Intercept**	**Slope**	**R- Square**
Industry Risk Premium Estimates:			
--Our DCAPM	4.442(4.51)***	0.370(2.92)***	19.58%
--GCAPM	4.775(3.73)***	0.325(1.96)**	9.99%
--Our Fama-French DCAPM	2.861(2.58)***	0.773(4.02)***	31.60%
--Fama-French 3-Factor	8.218(11.86)***	-0.154(-1.47)	5.79%
--Gebhardt-Lee-Swaminathan	7.241(17.03)***	0.005(0.04)	0.00%
Panel B. Dependent Variable: Industry Risk Premium Estimate of Gebhardt-Lee-Swaminathan			
Industry Risk Premium Estimates:			
-- Our DCAPM	0.863(0.65)	0.237(1.38)	5.13%
-- Our GCAPM	2.287(1.36)	0.050(0.23)	0.15%
-- Fama-French DCAPM	1.305(0.79)	0.240(0.83)	1.93%
-- Fama-French 3-Factor	1.343(1.56)	0.212(1.62)	6.97%

***Significant at the 0.01 level.
**Significant at the 0.05 level.

cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The consistently better performance of the domestic CAPM surprises us, given the extensive integration in the world financial markets and arguments for the global CAPM over the domestic CAPM. Perhaps the explanation is that US practitioners apply the domestic CAPM, as suggested in standard textbooks when they should be using the global CAPM. An alternative explanation is that US practitioners believe a domestic market index is a better benchmark for their investment decisions than is a global index. By extending our study to smaller US companies and to non-US companies, we might be able to shed more light on this question. We leave this possibility to future research.

We also find significant and consistently positive associations between our *ex ante* risk premium and beta estimates. These findings are consistent with the reports in a number of other studies that use *ex ante* return estimates.■

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DISCOVERY REQUEST NO. 29:

Regarding Dr. Morin's testimony at page 4, lines 19-21 that "The results were adjusted...for the... risks faced by CGC... on account of its very small size and declining demand," identify the magnitude, such as 11.5% for example, and show how it was adjusted for a) small size, b) declining demand. Indicate the magnitude of each adjustment, and identify which is more important in Dr. Morin's opinion.

Response:

The 50 basis points adjustment is based on: 1) utility bond yield spreads differentials between A-rated and Baa-rated bonds, 2) on observed beta differentials, 3) on differential common equity ratio requirements for S&P Business Risk Score, 4) the observed risk premium for small companies, and 5) application of judgment.

Utility bond yield spreads differentials between A-rated and Baa-rated bonds are currently 40 basis points.

The CAPM formula was also referenced to approximate the return (cost of equity) differences implied by the differences in the betas between the average natural gas utility company and CGC. The basic form of the CAPM, as discussed in Dr. Morin's testimony, states that the return differential is given by the differential in beta times the market risk premium, (R_M - R_F). To the extent that CGC's beta is approximately 0.07 higher than the natural gas industry utility average on account of its small size[1], the return differential implied by the difference of 0.07 in beta is given by 0.07 times (R_M - R_F). Using an estimate of 7.2% for (R_M - R_F), the return adjustment is close to 50 basis points.

Assuming that CGC would be assigned a higher Business Risk Score relative to the average risk gas utility on account of its small size and higher demand risk, according to S&P guidelines, the difference in required debt ratio between adjacent Business Risk categories is 3-4%. In other words, for a utility with a business risk score of 4 would require a 3-4% higher common equity component of capital structure than a utility with a lower business risk score of 3 in order to compensate for the higher business risk. The 3%-4% higher common equity requirement translates into approximately a 40 basis

[1] For securities for which there is only periodic trading, beta estimates are downward biased. This is because observed returns contain stale information about past period returns rather than current period returns. Intuitively, suppose the stock market index surges forward but that an individual company stock price remains unchanged due to lack of trading, the estimated beta is imparted a downward bias. The stock is unable to catch up to market-wide movements and appears to be a lower beta stock.

points adjustment.

The relationship between firm size and return cuts across the entire size spectrum but is most evident among smaller companies that have higher returns than larger ones on average. Ibbotson Associates' well-known historical return series publication covering the period 1926 to the present reinforces this evidence (Ibbotson Associates' *2004 Yearbook, Valuation Edition*). To illustrate, the Ibbotson data suggests that under SIC Code 49, *Electric, Gas & Sanitary Services*, the average return for that group over an almost 80-year period was 14.03% for the small-cap company group and 10.86% for the large-cap group, more than a 300 basis point difference. This is true for all industry groups. Overall, for the period 1926-2004, Ibbotson finds that the smaller companies have experienced returns that are not fully explainable by their higher betas, and that the excess return of that predicted by the CAPM increases as size decreases, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. Ibbotson Associates provides estimates of the size premium required to be added to the basic CAPM cost of equity, shown in the table below.

Ibbotson Estimates of Size Premiums

Size	Smallest Market Cap ($000s)	Premium
Large-cap	4,794,027	0
Mid-cap	1,167,040	0.91%
Low-cap	330,797	1.70%
Micro-cap	0.332	4.01%

Grabowski and King (1999, 2000) examine the historical returns of publicly listed common stocks over the 1963-1998 period, segregated into 25 equal-size portfolios based on various measures of company size, including market value of equity, assets, sales, and number of employees. As was the case from the Ibbotson findings, it is clear from the Grabowski & King results that beta is inversely related to company size. The betas range from 0.91 for large-cap companies to 1.39 for small-cap companies. Returns vary inversely to size as well, ranging from 14.2% for large-cap stocks to 22.9% for small-cap stocks over that period. Grabowski and King also find a systematic relationship between the achieved equity premium and size and that the higher returns realized by small-cap stocks exceed those predicted by the CAPM. For example, take portfolio #10 with a beta of 1.19. Given the risk-free rate of 7.6% and market risk premium of 6.2% prevailing over the 1963-1997 study period, the CAPM estimate of the cost of equity is 14.94%, in contrast to the actual average return of 15.17% for portfolio #10:

$$\begin{aligned} K &= R_F + \beta\,(MRP) \\ &= 7.6\% + 1.19\,(6.2\%) \\ &= 14.98\% \end{aligned}$$

The implication of the Grabowski and King study is that investors in small-cap stocks should add 0.23% (i.e., 15.17% - 14.94% = 0.23%) to the CAPM-derived cost of equity when estimating the required return of a company with a market capitalization similar to that of portfolio #10, about $2,000 million.[2]

Based on all these considerations, Dr. Morin estimated the risk differential between CGC and the average risk natural gas utility to be at least 50 basis points.

It is difficult to disaggregate the 50 basis points adjustment into finer portions. Total investment risk results from a multi-dimensional blend of several factors, including demand risks, regulatory risks, financial risks, and size. The demand risk component can in turn be disaggregated into sub-factors, including concentration of demand, customer mix, and service territory economics. It is difficult to quantify the exact impact of any given factor, such as business risk, on the company's total risk, let alone the impact of sub-factors. Investors examine a number of qualitative and quantitative factors before rendering a risk decision, that such factors are considered both individually and collectively. In Dr. Morin's judgment, 25 of the 50 basis points risk adjustment is attributable to company size.

[2] Updates are published annually in the Standard & Poor's Corporate Value Consulting Risk Premium Report by Roger J. Grabowski and David W. King at www.Ibbotson.com

DISCOVERY REQUEST NO. 30:

Regarding Mr. Morley's testimony at page 18, line 3-7, provide a statement by an auditor, independent of AGLR, where the auditor states "the consolidated financial statements of AGL Resources present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at March 31, 2006;" or any other similar statement by an independent auditor where March 31, 2006 is utilized.

Response:

The financial statements of AGL Resources Inc. are not audited on a quarterly basis. However, Quarterly financial statements are reviewed and analyzed by AGLR's independent auditors and many of the same procedures that are applied to the financial statements during an annual audit are applied during the quarterly review process. The absence of an audit opinion does not render the financial information of AGLR as of March 31, 2006 unreliable nor should it preclude the use of such information in determining the appropriate capital structure of AGLR.

The Securities and Exchange Act of 1934 requires the same level of accuracy, completeness, due diligence and integrity for quarterly financial information filed in SEC Form 10-Q as it does for annual information filed in SEC Form 10-K. Additionally, the same criminal penalties, including fines and imprisonment to our CEO and CFO, apply to inaccurate or misleading financial information filed in SEC Forms 10-Q and 10-K.

Additionally, SEC Form 10-Q is widely used as a reliable source of information by the investment community in monitoring the financial performance of publicly traded companies. Rating agencies, investment analysts, the New York Stock Exchange and the NASDAQ all rely on information provided quarterly in SEC From 10-Q, even though such information may or may not be audited.

DISCOVERY REQUEST NO. 31:

Regarding AGLRs SEC 10-K form filed February 10, 2006 with the United States Securities and Exchange Commission, page 83 lists categories for long-term debt, such as medium-term and senior notes. For each category list each note or bond, its interest rate, and its maturity date. Indicate if the interest rate is fixed or variable. If the rate is variable, provide the terms and conditions by which the debt instrument's interest rate is determined and provide a sample calculation.

Response:

Please see attached Schedule CAPD 31 – 1.

Categories of Long-Term Debt as of Decemebr 31, 2005

	Balance 12/31/05		Interest Rate	Fixed or Variable	Due Date
Senior Notes					
Issued 3/01	300,000,000		7.125%	Fixed	1/14/11
Issued 7/03	225,000,000		4.45%	Fixed	4/15/13
Issued 10/04	250,000,000		6.00%	Fixed	10/1/34
Issued 12/04	200,000,000		4.95%	Fixed	1/15/15
Total Senior Notes	**675,000,000**				
Revenue Bonds					
7/94 Issue	46,500,000	**(a)**	3.48%	Variable	10/1/22
7/94 Issue	20,000,000	**(b)**	3.55%	Variable	10/1/24
6/96 Issue	39,000,000	**(c)**	3.75%	Variable	6/1/26
6/97 Issue	54,600,000		5.70%	Fixed	6/2/32
12/98 Issue	40,000,000		5.25%	Fixed	11/1/33
Total Revenue Bonds	200,100,000				

Variable bond interest rates are provided every 35 days on the July '94 issued bonds and daily for the June '96 issued bonds. For the July '94 bonds, the rate is determined by auction whereby the rate is determined by the highest bidder for the bonds every 35 days. The rates are provided by the trustee of the bonds, Bank of New York. For the June '96 revenue bonds, the rate is determined daily based on the market for that day. The rate is provided by the trustee of the bonds, Wachovia. Given the manner in which the rates are determined - based on the market and what an investor is willing to pay at that time - there are no examples on how the rate is calculated to provide.

Categories of Long-Term Debt as of Decemebr 31, 2005

	Balance 12/31/05	Interest Rate	Fixed or Variable	Due Date
Preferred Stock/Notes Payable to Trusts				
Issued 6/97	75,000,000	8.17%	Fixed	6/1/37
Issued 5/01	150,000,000	8.00%	Fixed	Retired Q2 2006
Total Preferred Stock	225,000,000			
MTNs				
9.10% Due 02/01/21	30,000,000	9.10%	Fixed	Due 02/01/21
8.70% Due 04/01/22	25,000,000	8.70%	Fixed	Due 04/01/22
8.55% Due 04/15/22	6,000,000	8.55%	Fixed	Due 04/15/22
8.55% Due 04/01/22	5,000,000	8.55%	Fixed	Due 04/01/22
8.55% Due 05/13/22	10,000,000	8.55%	Fixed	Due 05/13/22
8.40% Due 06/05/12	5,000,000	8.40%	Fixed	Due 06/05/12
8.30% Due 06/19/12	5,000,000	8.30%	Fixed	Due 06/19/12
8.30% Due 07/01/12	5,000,000	8.30%	Fixed	Due 07/01/12
7.00% due 01/27/15	11,250,000	7.00%	Fixed	Due 01/27/15
6.55% due 11/20/26	10,000,000	6.55%	Fixed	Due 11/20/26
6.55% due 11/20/26	10,000,000	6.55%	Fixed	Due 11/20/26
6.55% due 11/20/26	10,000,000	6.55%	Fixed	Due 11/20/26
7.20% due 07/17/17	20,000,000	7.20%	Fixed	Due 07/17/17
7.20% due 07/17/17	2,000,000	7.20%	Fixed	Due 07/17/17
7.30% due 07/15/27	33,500,000	7.30%	Fixed	Due 07/15/27
7.30% due 07/15/27	10,000,000	7.30%	Fixed	Due 07/15/27
7.30% due 07/15/27	10,000,000	7.30%	Fixed	Due 07/15/27
Total Medium Term Notes	207,750,000			
Senior Note Issued in June 2006				
Issued - 6/06	175,000,000	6.375%	Fixed	7/15/06

Note - the interest rates provided in the above schedule represents rate on the face amount of each corresponding debt instrument and does not include issuance or discount costs or the impact of treasury locks, which may be used to hedge against interest risk and lock in the effective rate of a debt instrument. The Company included the impacts of such items in its long-term debt cost of 6.27%. Additionally, the above schedule does not include interest rate swaps or capital leases.

DISCOVERY REQUEST NO. 32:

Regarding Exhibit MJM-4, Schedule 1, provide the source data and display the calculations which lead to the figure of 6.27% as the cost of long-term debt. If this material is provided in the material submitted within the minimum filing requirements or in another response, identify the response where such material is provided.

Response:

Please refer to the Company's response to TRA FG Item No. 81. Additionally, refer to the Company's response to CAPD – 14 for the same information electronically.

DISCOVERY REQUEST NO. 34:

Regarding Dr. Morin=s testimony, admit the following:

(a) Northwest Natural Gas and Atlanta Gas Resources are not in the same general part of the United States.

(b) In every case where Dr. Morin has testified and used betas in his analysis, he uses Value Line's betas and no other betas.

(c) According to Dr. Morin, the cost of equity is determined by investors' expectations.

(d) Investors' expectations are not easily identified.

(e) Investors' expect too much return from the market.

(f) According to Dr. Morin, the more investors expect from a regulated utility, the higher the rates that a regulatory authority should approve.

(g) Value Line's Common Equity Ratios shown on Exhibit RAM-8 are not calculated by dividing Common Equity by the Sum of Common Equity, Long-Term Debt and Short-Term debt.

If any of these requests is not admitted, please explain.

Response:

(a) Admit. Northwest Natural Gas and AGL are not in the same geographic part of the U.S. Investors are not limited to geographical areas in composing portfolios of securities. There are no barriers to the flow of investment funds. Similarity of risk vs return in various investment opportunities is considered, regardless of geographical location in a global capital market.
(b) Admit. Value Line betas are widely available and well-known to investors. Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and

individual investors. The Value Line data are commercially available on a timely basis to investors in paper format or electronically.

(c) Admit. The cost of equity is set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

(d) Deny. Investors' expectations can readily be identified from various conceptual frameworks, including DCF, CAPM, and Risk Premium approaches. Informed judgment is required in the implementation of these approaches.

(e) Deny. Investors expect a return commensurate with the risk of the investment and commensurate with returns offered on comparable risk alternative investments.

(f) Admit. All else remaining constant, the higher the cost of capital, the higher is the cost of service and the revenue requirement.

(g) Admit. Value Line Common Equity Ratios shown on Exhibit RAM-8 are calculated by dividing Common Equity by the Sum of: Common Equity, Preferred Stock, and Long-Term Debt

DISCOVERY REQUEST NO. 35:

Regarding Exhibit MJM-4, Schedule 1, provide the source data and display the calculations which lead to the figure of 7.23% as the ratio of short-term debt. If this material is provided in the material submitted within the minimum filing requirements, identify the response where such material is provided.

Response:

Please refer to the Company's response to TRA FG Item No. 81. Additionally, refer to the Company's response to CAPD – 14 for the same information electronically.

DISCOVERY REQUEST NO. 76:

Please provide a copy of the definitions of the metrics reported in MFG #28 and the metrics reported in compliance with GA PSC Docket 15295-U. For instance, please explain what, "Answered" means in the "Number of Calls Answered" and the Number of Calls offered % answered with 120 seconds". If a Tennessee consumer calls in and gets a busy signal - is this an "answered call"?

Response:

Number of Calls Answered – Number of calls answered by a CSR

Number of Calls Offered – Number of calls answered by a CSR plus Abandoned calls

Percentage of Calls Answered with 120 seconds – Percentage of offered calls answered by a CSR with 120 secs. It is calculated by taking the total number of calls answered by a CSR within 120 seconds divided by total calls offered

Average Speed of Answer – Average length of time from the switch being answered by a CSR

Number of Abandoned Calls – Calls that are abandoned between the switch and being answered by a CSR

Percentage of Abandoned Calls – Percentage of calls that are abandoned between the switch and being answered by a CSR

If a Tennessee consumer calls in and receives a busy signal, this is not considered an answered call.

DISCOVERY REQUEST NO. 95:

Please explain why your, "Business Process Outsourcing" as presented to the TRA on June 26, 2006 was not included as a discussion item in this docket.

Response:

The Company included information on the business process outsourcing (BPO) in its response to TRA FG No. 14, part (b). Additionally, the Company included cost reductions of approximately $185,000 in its cost of service. This cost reduction is referenced in the aforementioned filing guideline as well as the direct testimony of Michael Morley. The Company did not deem it necessary to include further discussion on the BPO since it had made a presentation to the TRA on June 26, 2006, and the presentation is a matter of public record.

DISCOVERY REQUEST NO. 96:

Please explain why only 6 bids were requested from vendors from North America (USA & Canada), South America and India.

Response:

The six organizations were selected based upon their expertise in the Call Center/Customer Service environments as well as their overall outsourcing capabilities. Moreover, AGL Resources felt confident that any one of these organizations would be able to delivery the level of service required. Lastly, due to the intense selection process, having more than six vendors would have added unnecessary costs due to time and manpower requirements.

DISCOVERY REQUEST NO. 97:

Please explain the criteria utilized to develop the AGartner rankings as referenced in AGL's presentation.

Response:

Gartner creates rankings based upon their published research.

DISCOVERY REQUEST NO. 98:

Please explain why the AGartner rankings were the criteria utilized in the weighting of the rankings, and why AGartner was utilized instead of other Call Center authorities.

Response:

The Gartner Group is a leader of research and analysis to the global IT industry. They guarantee their clients information independent from commercial interests resulting in research advice unhindered by compromise. According to their website, Gartner's 1200 research analysts serve clients around the world from operations in 75 countries. Their interactions with 45,000 clients, representing 10,000 distinct organizations worldwide, enable them to make connections, understand patterns and discover trends that no other research firm can envision. In fact, they publish tens of thousands of pages of original research annually and answer more than 215,000 client questions every year. 66% of the Fortune 1000 and 80% of the Global 500 support their key technology decisions with Gartner insight. The Request for Proposal that AGL Resources submitted to the vendors for business process outsourcing encompassed more activities than just call center support. In order to identify the appropriate partner for AGL Resources' needs it was determined to use a ranking of proposed vendors who could provide solutions beyond just call center. We felt that the Gartner Group's studies provided that level of independent research.

DISCOVERY REQUEST NO. 100:

Why BPO : AImmediate Service Level improvement- please detail the metrics utilized in this analysis and compare BPO versus current operating levels.

Response:

Currently Chattanooga Gas provides an 80/120 Service Level. BPO will provide the following:

80/120 immediately
80/60 within 7-18 months
80/30 within 19 months

DISCOVERY REQUEST NO. 101:

For what period of time has AGL entered into service contract with Wipro?

Response:

54 months

DISCOVERY REQUEST NO. 102:

How will AGL/Chattanooga Gas maintain security over customer data to guarantee Tennessee consumers privacy?

Response:

The Agreement between AGL Resources and Wipro contains a number of distinct provisions that address information security. The parties have agreed to treat all customer data as confidential. As such, neither AGLR nor Wipro employees may disclose, license, allow access to or sell such information to any other person(s). Further, the agreement has specific provisions that address the technical aspects of data security such as encryption. Finally, all personnel working with AGLR customer data will be trained. Moreover, no Wipro employee will have access to a printer or will be able to download any customer information from the systems that interact with AGLR.

DISCOVERY REQUEST NO. 103:

How will the difference in cost between current cost versus future cost allocated to CGC be treated in this case?

Response:

As referenced in the direct testimony of Michael J. Morley, page 8, lines 19 – 22, the Company has included $185,000 in reduced AGL Services costs in this case as a result of the business process outsourcing initiative.

DISCOVERY REQUEST NO. 104:

How will Spanish-speaking Tennessee consumers be served (if different than English- speaking consumers)?

Response:

Spanish speaking consumers will be handled by Spanish speaking CSRs. If no Spanish speaking CSRs are available, an interpreter service will be used to translate the call. This is the same process used in Riverdale, Georgia today.

DISCOVERY REQUEST NO. 108:

Identify all persons known to you, your attorney, or other agent who have knowledge, information or possess any document(s) or claim to have knowledge, information or possess any document(s) which support each fact you rely on to support your contentions and requests for relief in this docket.

Response:

CGC refers the CAPD to the witnesses who submitted pre-filed testimony with the Petition it filed in this matter on June 30, 2006. Since the intervenors' rebuttal testimony has not yet been provided, CGC is not aware of issues that may be raised and reserves the right to identify additional witnesses as necessary. If CGC identifies additional witnesses for rebuttal testimony, this response will be supplemented as soon as practicable after such identification.

DISCOVERY REQUEST NO. 109:

If your response to any request for admission is other than an unqualified admission, state for each such request for admission the following:

(a) All facts that you contend could support in any manner your response to the extent it is not a complete admission;

(b) For any information you contend is incorrect or inaccurate provide the correct information;

(c) Identify all documents, or any tangible or intangible thing that supports in any manner your lack of admission or your qualification of your admission;

(d) The name and address of the custodian of all tangible things identified in response to subsection (b) of this interrogatory; and

(e) The name and address of all persons, including consultants purporting to have any knowledge or factual data upon which you base your lack of admission or your qualification of your admission.

Response:

See CGC's responses to CAPD Nos. 4, 7(f), 8, 107 and 108.

DISCOVERY REQUEST NO. 107:

State each fact you rely on to support your contentions and requests for relief in this docket.

Response:

To the best of its knowledge, the Company has already stated or will state all such facts in its pre-filed testimony and exhibits filed June 30, 2006, its responses to the minimum filing guidelines, and its responses to the CAPD's, Staff's and CMA's discovery requests. To the extent CGC identifies additional facts or additional issues arise, CGC will supplement the appropriate filing or response prior to the hearing on the merits and/or include such information in its pre-filed rebuttal testimony.

DISCOVERY REQUEST NO. 33:

Regarding Mr. Buchanan's testimony at page 16, lines 14-19, provide in a working excel file display the calculations and data used to develop the "Demand Units" for the residential, commercial and industrial customers.

Response:

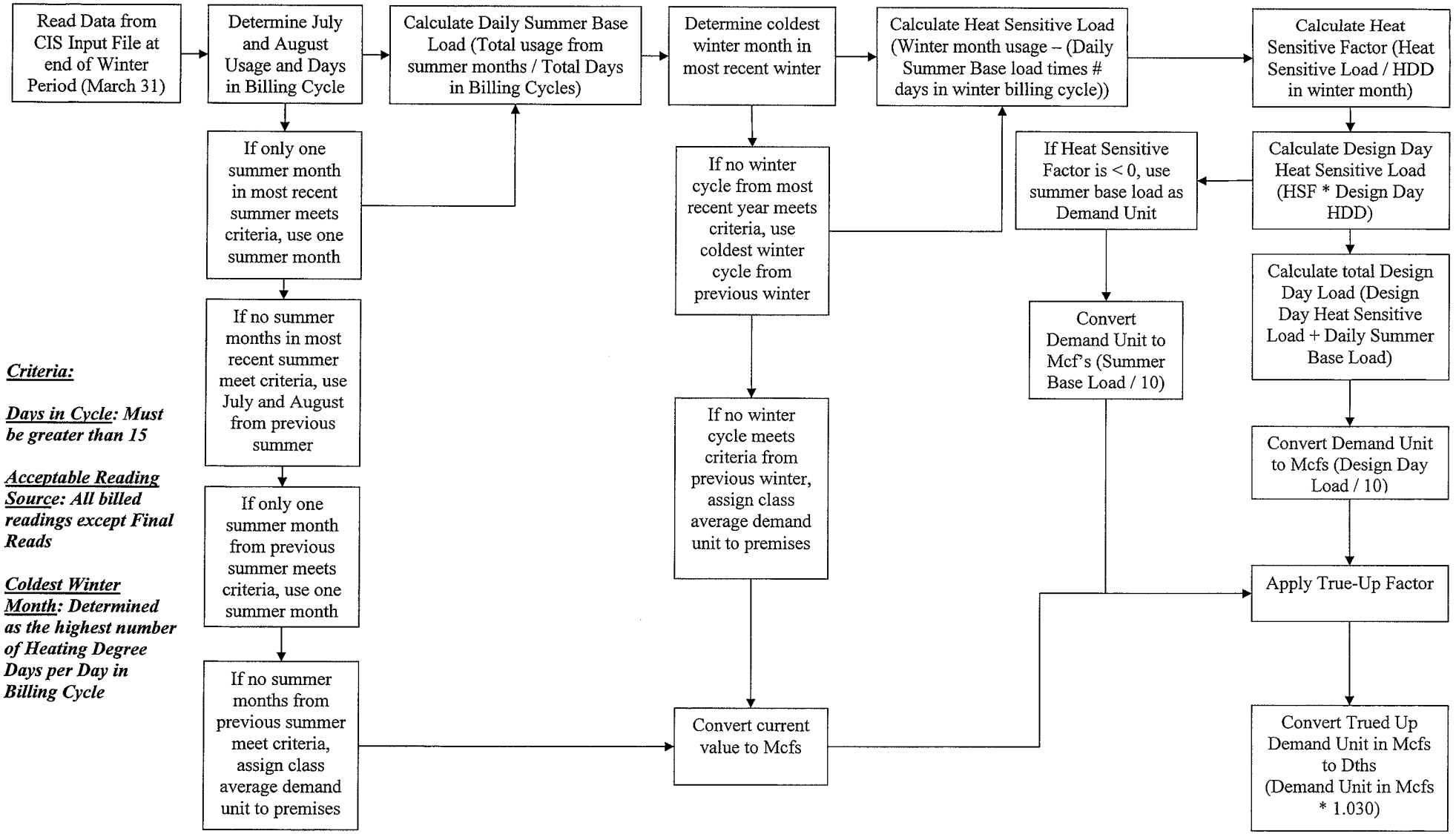
Demand units are a measure of the firm capacity on CGC's distribution system that is needed by the customer for use on a design day. In other words, the demand unit represents the customer's peak demand, measured in decatherms.

For the Residential and Commercial customer classes, a demand unit was calculated for each of the approximately 61,000 residential and commercial premises on the Company's distribution system. Due to the size of the dataset, the actual calculation is performed by the Company's Customer Information System ("CIS") mainframe. The calculation, similar to the calculation of DDDC factors performed by CIS for Atlanta Gas Light Company, is done at the premises-level. The calculation is based on each premises' coldest billing cycle in the most recent winter period season and its average usage during the most recent summer. Therefore, the set of data used to develop the demand units for residential and commercial customers is too large to include in response to this request.

However, the methodology for calculating the demand units for the Residential and Commercial customer classes is documented in the attached flow chart. This flow chart shows the steps taken by the CIS to calculate the demand factor for each premises. Once the demand units are calculated for each premises, the demand units are aggregated by class. The aggregation can be seen on the workpaper previously filed as "Workpaper – Calculation of Design Day Capacity" and filed here as Schedule CAPD 33 A.

For the I1/T2 (firm sales and transportation) and I1/T2 + T1 (Interruptible transportation with some firm back-up) industrial customer classes, the demand factors were calculated in the same manner as the methodology established in the Company's tariff for the current demand factor that is used to bill the current demand charge. The demand factors for each customer can be seen in the Company's Revenue Model, filed as part of MFG 25 – Workpapers.

RES AND COM DEMAND UNIT CALCULATION PROCESS



Criteria:

Days in Cycle: Must be greater than 15

Acceptable Reading Source: All billed readings except Final Reads

Coldest Winter Month: Determined as the highest number of Heating Degree Days per Day in Billing Cycle

Chattanooga Gas
Calculation of Dedicated Design Day Capacity (DDDC)

Customers

	Active	Inactive	Total
Residential	53,093	8,534	61,627
Commercial < 4000 Therms	6,669	2,668	9,337
Commercial > 4000 Therms	1,719	33	1,752
Total Commercial	8,388	2,701	11,089
Multi-Family	2	0	2
Total Customers	61,483	11,235	72,718

Raw DDDC in Mcfs

	Active	Inactive	Total
Residential	52,582	1,502	54,084
Commercial < 4000 Therms	13,832	491	14,324
Commercial > 4000 Therms	30,025	445	30,469
Total Commercial	43,857	936	44,793
Multi-Family	99	0	99
Total Raw DDDC in Mcfs	96,538	2,438	98,976

BTU Factor	1.030

Raw DDDC in Dths

	Active	Inactive	Total
Residential	54,160	1,547	55,707
Commercial < 4000 Therms	14,247	506	14,753
Commercial > 4000 Therms	30,925	458	31,383
Total Commercial	45,173	964	46,137
Multi-Family	101	0	101
Total Raw DDDC in Dths	99,434	2,511	101,945

Total Design Day Capacity Dths		121,974
Less DDDC from:		
	I1/T2	8,788
	I1/T2 + T1	3,976
Total System Dths from CIS Firm		109,210
Less Commercial > 4000 Therms		30,925
Total System to Allocate		78,285

Calculation of True Up Factor

Active Raw DDDC less Commercial > 4000 Therms	Total System less Commercial > 4000 Therms	True Up Factor
68,509	78,285	1.1427

Trued Up DDDC in Dths

	Active	Inactive	Total
Residential	61,889	1,768	63,657
Commercial < 4000 Therms	16,280	578	16,858
Commercial > 4000 Therms	30,925	458	31,383
Total Commercial	47,205	1,036	48,241
Multi-Family	115	0	115
Total Trued Up DDDC in Dths	109,209	2,804	112,013

Average Trued Up DDDC per Customer in Dths

	Active	Inactive	Total
Residential	1.166	0.207	1.033
Commercial < 4000 Therms	2.441	0.217	1.806
Commercial > 4000 Therms	17.990	13.879	17.913
Total Commercial	5.628	0.384	4.350
Multi-Family	57.500	0.000	57.500
System Average	1.776	0.250	1.540

DISCOVERY REQUEST NO. 50:

According to page 16 of the TRAs October 20, 2004 Order in Docket No. 04-00034, "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." Explain how the Company's proposed Bare Steel and Cast Iron Pipeline Replacement Program (PRP) tracker is consistent with the language from the order quoted above. Also, explain all facts and provide copies of all documents that justify the Company's proposed PRP tracker in light of the TRAs order.

Response:

The Company's proposed Bare Steel and Cast Iron Replacement Program (PRP) tracker is consistent with the language from the TRA's order in Docket No. 04-00034. There is certainly more than one way to appropriately recover costs incurred by the Company with rate base recovery being one example and a tracker being another. No where in the order did the TRA say that the use of a tracker was an illegal means of recovering costs.

In the order, all the TRA did was to select a recovery mechanism that was preferable to them based on the facts presented at the time. The Company has now proposed a tracker mechanism again two years later because it stills believes that a tracker would better accelerate the replacement of bare steel and cast iron mains in Chattanooga.

DISCOVERY REQUEST NO. 51:

On p. 4 of Mr. Lonn's testimony he states, "The replacement will result in not having to repair an ever increasing number of leaks related to bare steel and cast iron pipeline." If this is so, explain why an aggressive replacement program was not cost beneficial and therefore was not implemented by management in prior years

Response:

The Replacement of Bare Steel and Cast Iron infrastructure is a very capital intensive process, projected to be in excess of $35.1 Million dollars total cost to replace the 86 miles, with no revenue generated to offset those expenditures as is the case with new business extensions. From a solely cost based analysis based on reduced numbers of the leaks, the program would not be cost beneficial, hence the need for the rider. The point of Mr. Lonn's quote is simply that the number of corrosion leaks will continue to increase over time if the pipe is not replaced.

DISCOVERY REQUEST NO. 52:

Provide a comparison between the costs (and feet) involved with replacement projects budgeted per year over the past three years with projects promoted for the first three years of the PRP

Response:

Over the past three years, 14 miles of bare steel and cast iron main has been retired from the system at an average cost of $39.76 per foot. For the next three years, the projection is for a total of over 32 miles of bare steel and cast iron main at an average cost of $62.43 per foot.

DISCOVERY REQUEST NO. 53:

Provide a summary of main replacement since CGCs 04-00034 case.

Response:

At the time of submission of the Company's rate case in 2004, the Company had 100 miles of Bare Steel and Cast Iron main remaining. At the time of filing of the 2006 rate case there were 86 miles remaining, so there has been a total of 14 miles retired over that time period.

DISCOVERY REQUEST NO. 55:

Why was the pipe replaced? (I.e., Road Projects, Leaks, routine replacement, etc).

Response:

The pipe was replaced for a combination of reasons. Some was replaced in conjunction with road relocation projects and others were replaced as part of the Company's on going bare steel and cast iron replacement program.

DISCOVERY REQUEST NO. 56:

Does CGC perform annual leak surveys on the bare steel and cast iron? Is this leak survey independent of regular leak surveys that are required under the pipeline safety regulation, 49 CFR section 192.723?

Response:

CGC performs an annual leak survey in parts of its system, which is called the "Business District Survey". This area encompasses portions of the bare steel and cast iron pipe. The remainder of the bare steel and cast iron pipe is surveyed on a three year cycle. These surveys are the surveys required under 49 CFR Section 192.723. There are no independent surveys conducted on just the bare steel and cast iron.

DISCOVERY REQUEST NO. 57:

Has CGC increased surveying the bare and cast iron for leaks due to safety concerns?

Response:

The Company has not increased leak surveying beyond the current annual and three year cycles referenced in question 56 above.

DISCOVERY REQUEST NO. 58:

What is your present frequency for surveying for gas leaks on the bare steel and cast iron?

Response:

Please see the answer to 56 above.

DISCOVERY REQUEST NO. 59:

What requirement, standard or criteria is used to base your frequency surveying for gas leaks on bare steel and cast iron pipe?

Response:

The Company's Operations Procedures Manual (OPM) which defines the frequency at which leak surveys are conducted is the standard which the Company uses. This manual was created by the Company as required by CFR Part 192 and has been submitted and updated as necessary to the TRA Staff as required.

DISCOVERY REQUEST NO. 60:

Please detail how much of an increase in leaks was noticed during surveys over the last two years? (Please detail analysis by year).

Response:

The corrosion leak totals repaired for the Company from 2003 through 2005 are as follows:

Year	Corrosion Leaks
2003	34
2004	63
2005	63
Change	29

DISCOVERY REQUEST NO. 61:

How many cast iron fractures over the last two years were due to General graphitization and Localized graphitization? (Please provide copies analyzing the pipe tested).

Response:

There have been three cast iron fractures over the past two years. No determination was made as to whether the graphitization was general or localized due to there being no broken pieces available to test.

DISCOVERY REQUEST NO. 62:

Please detail the company's guidelines for replacing bare steel and cast iron pipe?

Response:

The Company's engineers will utilize the leak information it has available together with information from local supervision Additionally, it will also consider how the segments operate within the system and the available budget to determine where their next replacement project should be and the particular limits of the proposed project.

DISCOVERY REQUEST NO. 63:

Do the pipeline safety regulations provide guidelines to consider replacing pipe?

Are these guidelines being used by CGC?

Response:

Current pipeline safety regulations indicate that if cast iron pipe is identified as having generalized graphitization to a degree where a fracture might result, that it must be replaced. In addition, the regulations require that cast iron pipe that is excavated must be protected against damage. An operator's compliance with these requirements can be enhanced by incorporating all of the operator's cast iron responsibilities in an effective cast iron program that is designed to identify and replace cast iron pipe that may threaten the public.

For bare steel, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

As far as complying with these guidelines, yes the Company does.

DISCOVERY REQUEST NO. 64:

Are the guidelines subject to the routine maintenance and operation of the gas system?

Response:

Leak repairs are considered routine maintenance of the system, so yes the guidelines are subject to routine maintenance, since repair is an acceptable type of compliance with the Federal Regulations.

DISCOVERY REQUEST NO. 65:

How does CGC presently determine prudence of the cost associated with pipe replacement?

Response:

The Company normally bids the work out in order. However there is no obligation for the Company to accept that price if they believe it to be unreasonable.

DISCOVERY REQUEST NO. 66:

If the TRA does not approve your surcharge proposal for pipe replacement, please provide an acceptable schedule of pipeline replacement through completion of the bare steel Cast Iron Mains. If dissimilar to the proposal detailed in Exhibit RRL-1, please provide a detailed reconciliation analysis for any variance.

Response:

The Company cannot provide a schedule for pipe replacement if the TRA does not approve the surcharge proposal. The schedule for replacement proposed is based on a proposal for an accelerated program with a defined completion date and an associated recovery mechanism. Without all of those components, the Company will have to continue to manage repair vs. replacement decisions on an ongoing case by case basis, considering all facts available at that time, so no schedule can be provided.

DISCOVERY REQUEST NO. 67:

Please provide Department of Transportation 7100 annual reports for CGC since 1999.

Response:

Please see attachments, which are all of the annual DOT 7100 forms for CGC's distribution system since 1999.

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs
Administration

ANNUAL REPORT FOR CALENDAR YEAR 1999
GAS DISTRIBUTION SYSTEM

INITIAL REPORT [X]
SUPPLEMENTAL REPORT [ ]

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF COMPANY OR ESTABLISHMENT
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
6125 Preservation Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee, 37416
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
(When Known) / 0 / 2 / 2 / 8 / 8 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
Same
Number and Street
City and County
State and Zip Code

5. STATES IN WHICH SYSTEM OPERATES : Tennessee

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	94			605	701	22				
NO. OF SERVICES	1,308			16,172	43,917					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR 1,422

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL		219	240	192	37	11
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON			5	16		1
PLASTIC 1. PVC						
2. PE		578	108	15		
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		797	353	223	37	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 61,457 AVERAGE SERVICES LENGTH 104 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL		13,027	4,307	125	21	
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON						
PLASTIC 1. PVC						
2. PE		39,779	4,119	18	1	
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		52,806	8,426	143	22	

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

PART C - TOTAL LEAKS

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION	35	24
THIRD PARTY	75	400
OUTSIDE FORCE	1	1
CONSTRUCTION DEFECT	0	1
MATERIAL DEFECT	0	0
OTHER	111	100

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR: 0

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for year ending 6/30 4.77 %.

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

George Comer, Manager
Prepared by (type/print)

(423) 490-4232
Area Code/Telephone Number

George Comer, Manager
Name and Title of Person Signing

(423) 490-4232
Area Code/Telephone Number

Authorized Signature

U.S. Department of Transportation

Research and Special Programs Administration

400 Seventh St. SW
Washington, D.C. 20590

Official Business
Penalty for Private Use $300

Information Resources Manager
Office of Pipeline Safety, DPS-3.3
Research and Special Programs Administration
400 7th Street, S.W.
Washington, D.C. 20590

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1676. Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 2000
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☒
SUPPLEMENTAL REPORT ☐

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF COMPANY OR ESTABLISHMENT
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
6125 Preservation Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee, 37415
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (When Known) 1 0 1 2 1 8 1

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
Same
Number and Street
City and County
State and Zip Code

5. STATES IN WHICH SYSTEM OPERATES : Tennessee

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	94			605	711	22				
NO. OF SERVICES	1,269			16,059	44,854					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR 1,432

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL		218	241	192	37	11
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON			5	16		1
PLASTIC 1. PVC						
2. PE		588	108	15		
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		808	354	223	37	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 62,182 AVERAGE SERVICES LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL		12,980	4,203	124	21	
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON						
PLASTIC 1. PVC						
2. PE		40,822	4,212	19	1	
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		53,802	8,415	143	22	

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

Reproduction of this form is permitted.

PART C - TOTAL LEAKS

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION	26	14
THIRD PARTY	31	195
OUTSIDE FORCE	2	1
CONSTRUCTION DEFECT	2	4
MATERIAL DEFECT	0	0
OTHER	115	112

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR _____

PART D - TOTAL NUMBER OF KNOWN SYSTEM LEAKS SCHEDULED FOR REPAIR

_____

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for year ending 6/30 5.96 %.

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

Isaac Blythers
Prepared by (type/print)

(404) 584-3550
Area Code/Telephone Number

Isaac Blythers - Executive Vice President/ General Manager
Name and Title of Person Signing

(404) 584-3550
Area Code/Telephone Number

Authorized Signature

U.S. Department of Transportation

Research and Special Programs Administration

400 Seventh St. SW
Washington, D.C. 20590

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Information Resources Manager
Office of Pipeline Safety, DPS-3.3
Research and Special Programs Administration
400 7th Street, S.W.
Washington, D.C. 20590

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $25,000 for each violation. Form Approved for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122. OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 20 01
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☐
SUPPLEMENTAL REPORT ☐

1. NAME OF COMPANY OR ESTABLISHMENT
CHATTANOOGA GAS COMPANY

2. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (When Known) [ ][ ][ ][ ][ ]

3. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
6125 PRESERVATION DRIVE
Number and Street
CHATTANOOGA HAMILTON
City and County
TENNESSEE 37416
State and Zip Code

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
Number and Street
City and County
State and Zip Code

5. STATES IN WHICH SYSTEM OPERATES: TENNESSEE

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	72.	0	0	602	736	20				
NO. OF SERVICES	1183	0	0	15855	45792					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR 1450

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL	0	217	237	192	37	11
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON	0	0	4	15	0	1
PLASTIC 1. PVC						
2. PE	0	607	113	16	0	0
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS	0	824	357	223	37	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 62830 AVERAGE SERVICES LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 6"	OVER 8"
STEEL	0	12938	3960	120	20	0
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON						
PLASTIC 1. PVC						
2. PE	0	41464	4305	22	1	0
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS	0	54402	8265	142	21	0

Form RSPA F 7100.1-1 (11-88)
(Supersedes DOT F 7100.1-1)

Reproduction of this form is permitted.

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION	26	39
THIRD PARTY	77	152
OUTSIDE FORCE	0	3
CONSTRUCTION DEFECT	0	1
MATERIAL DEFECT	1	0
OTHER	93	70

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR: 0

0

Unaccounted for gas as a percent of total input for year ending 6/30: 3.528 %

Prepared by (type/print) — Area Code/Telephone Number

Name and Title of Person Signing — Area Code/Telephone Number

Authorized Signature

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678. Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 2002
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☐ X
SUPPLEMENTAL REPORT ☐

1. NAME OF COMPANY OR ESTABLISHMENT
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
2207 Olan Mills Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee 37421
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (When Known) / 0 / 2 / 2 / 8 / 9 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
SAME
Number and Street
City and County
State and Zip Code

5. STATES IN WHICH SYSTEM OPERATES : Tennessee

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	90			576	760	41				
NO. OF SERVICES	1,095			15,675	46,772					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR 1,467

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL		200	232	189	34	11
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON		2		16	22	1
PLASTIC 1. PVC						
2. PE		632	113	15		
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		834	345	220	56	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 63,542 AVERAGE SERVICES LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL		12,910	3,719	121	20	
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON						
PLASTIC 1. PVC						
2. PE		42,311	4,438	22	1	
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		55,221	8,157	143	21	

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

Reproduction of this form is permitted.

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION	45	12
THIRD PARTY	51	139
OUTSIDE FORCE		
CONSTRUCTION DEFECT		1
MATERIAL DEFECT		1
OTHER	191	111

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR 15

0

Unaccounted for gas as a percent of total input for year ending 6/30 2.94 %.

MAINS MILEAGES REPORTED REFLECT MORE ACCURATE FIGURES OUT OF THE COMPANY'S NEW MAPPING SYSTYEM.

Isaac Blythers
Prepared by (type/print)

404-584-3550
Area Code/Telephone Number

Isaac Blythers, President
Name and Title of Person Signing

404-584-3550
Area Code/Telephone Number

Authorized Signature

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs
Administration

ANNUAL REPORT FOR CALENDAR YEAR 2003___
GAS DISTRIBUTION SYSTEM

INITIAL REPORT " X
SUPPLEMENTAL REPORT "

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF COMPANY OR ESTABLISHMENT
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
2207 Olan Mills Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee 37421
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
(When Known) / 0 / 2 / 2 / 8 / 9 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
SAME
Number and Street
City and County
State and Zip Code

5. STATES IN WHICH SYSTEM OPERATES : Tennessee

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	57			605	782	38				
NO. OF SERVICES	1,028			15,553	47,977					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR 1,482

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL		200	229	188	34	11
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON		2	13	21	1	1
PLASTIC 1. PVC						
2. PE		651	116	15		
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		853	358	224	35	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 64,558 AVERAGE SERVICES LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL		12,909	3,532	120	20	
DUCTILE IRON						
COPPER						
CAST WROUGHT IRON						
PLASTIC 1. PVC						
2. PE		43,334	4,617	25	1	
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		56,243	8,149	145	21	

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

PART C - TOTAL LEAKS

CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION	20	14
THIRD PARTY	66	131
OUTSIDE FORCE		
CONSTRUCTION DEFECT		
MATERIAL DEFECT	1	
OTHER	238	184

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR 6

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

0

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for year ending 6/30 4.27 %.

PART F - ADDITIONAL INFORMATION

MAINS MILEAGES REPORTED REFLECT A MORE ACCURATE COUNT AND BREAKDOWN DUE TO THE ADDITION OF CORROSION INFORMATION TO THE COMPANY NEW MAPPING SYSTEM.

PART G - PREPARER AND AUTHORIZED SIGNATURE

Isaac Blythers
Prepared by (type/print)

404-584-3550
Area Code/Telephone Number

Isaac Blythers, President
Name and Title of Person Signing

404-584-3550
Area Code/Telephone Number

Authorized Signature

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1)

NOTICE: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

Form Approved
OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 2004
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☒
SUPPLEMENTAL REPORT ☐

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF OPERATOR
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
2207 Olan Mills Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee 37421
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
(When Known) / 0 / 2 / 2 / 8 / 8 /
AGL Resources

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
10 Peachtree Place, N.E.
Number and Street
Atlanta, Fulton
City and County
Georgia, 30309
State and Zip Code

5. STATE IN WHICH SYSTEM OPERATES / T / N / (provide a **separate** report for each state in which system operates)

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	56			601	808	34				
NO. OF SERVICES	1013			15684	49429					

2. MILES OF MAINS IN SYSTEM AT END OF YEAR : 1498

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL		200	228	184	34	11
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON		2	9	21	1	1
PLASTIC 1. PVC						
2. PE		664	121	23		
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		866	358	228	35	12

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR 66126 AVERAGE SERVICE LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL		12987	3570	120	20	
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON						
PLASTIC 1. PVC						
2. PE		44622	4781	25	1	
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS		57609	8351	145	21	

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980–1989	1990–1999	2000–2009	TOTAL
MILES OF MAIN	46	23	17	107	246	182	274	515	89	1499
NUMBER OF SERVICES	2024	1012	748	4708	10824	8008	12056	22660	4086	66126

PART C - TOTAL LEAKS ELIMINATED/REPAIRED DURING YEAR

CAUSE OF LEAK	Mains	Services
CORROSION	46	17
NATURAL FORCES		
EXCAVATION	68	123
OTHER OUTSIDE FORCE DAMAGE	1	
MATERIAL OR WELDS	7	2
EQUIPMENT		
OPERATIONS		
OTHER	157	146

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR 6

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

0

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for the12 months ending June 30 of the reporting year.

[(Purchased gas + produced gas)
minus (customer use + company use + appropriate adjustments)]
divided by (purchased gas + produced gas) equals percent unaccounted for.

Input for year ending 6/30 1.57 %.

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

Keith D. McDonald, Compliance Engineer
(type or print) Preparer's Name and Title

(404) 584-3736
Area Code and Telephone Number

Kmcdonal@Aglresources.com
Preparer's email address

(404) 584-3736
Area Code and Facsimile Number

Suzanne Sitherwood, SVP Southern Operations
Name and Title of Person Signing

404-584-3847
Area Code and Telephone Number

Authorized Signature

NOTICE: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122. Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ANNUAL REPORT FOR CALENDAR YEAR 2005
GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☒
SUPPLEMENTAL REPORT ☐

PART A - OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF OPERATOR
Chattanooga Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
2207 Olan Mills Drive
Number and Street
Chattanooga, Hamilton
City and County
Tennessee 37421
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
/ 0 / 2 / 2 / 8 / 8 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT
AGL Resources, 10 Peachtree Pl NE
Number and Street
Atlanta, Fulton
City and County
Georgia, 30309
State and Zip Code

5. STATE IN WHICH SYSTEM OPERATES: / T / N / (provide a **separate** report for each state in which system operates)

PART B - SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER	TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN	54			601	827	32					1514
NO. OF SERVICES	930			15794	51020						67744

2. MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL		199	228	184	34	11	656
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON		1	8	21	1	1	32
PLASTIC 1. PVC							
2. PE		680	123	23			826
3. ABS							
OTHER							
OTHER							
SYSTEM TOTALS		880	359	228	35	12	1514

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR

AVERAGE SERVICE LENGTH 109 FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL		12977	3607	120	20		16724
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON							
PLASTIC 1. PVC							
2. PE		46048	4946	25	1		51020
3. ABS							
OTHER							
OTHER							
SYSTEM TOTALS		59025	8553	145	21		67744

Form PHMSA F 7100.1-1 (12-05)

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980–1989	1990–1999	2000–2009	TOTAL
MILES OF MAIN	45	21	17	106	246	182	274	515	108	1514
NUMBER OF SERVICES	2024	1012	748	4613	10824	8008	12056	22660	5799	67744

PART C - TOTAL LEAKS ELIMINATED/REPAIRED DURING YEAR

CAUSE OF LEAK	Mains	Services
CORROSION	48	15
NATURAL FORCES	0	1
EXCAVATION	66	203
OTHER OUTSIDE FORCE DAMAGE	2	6
MATERIAL OR WELDS	7	7
EQUIPMENT	2	1
OPERATIONS	1	0
OTHER	118	174

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR 9

PART D - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

0

PART E - PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total input for the12 months ending June 30 of the reporting year.

[(Purchased gas + produced gas)
minus (customer use + company use + appropriate adjustments)]
divided by (purchased gas + produced gas) equals percent unaccounted for.

Input for year ending 6/30 3.13 %.

PART F - ADDITIONAL INFORMATION

PART G - PREPARER AND AUTHORIZED SIGNATURE

Scott Crider, Engineer
(type or print) Preparer's Name and Title

(404) 584-4697
Area Code and Telephone Number

scrider@aglresources.com
Preparer's email address

(404) 584-4807
Area Code and Facsimile Number

Suzanne Sitherwood, SVP Southern Operations
Name and Title of Person Signing

(404) 584-3847
Area Code and Telephone Number

Authorized Signature

DISCOVERY REQUEST NO. 68:

Please explain why 10.2 miles per year was used for pipe replacement scenario in your proposal as documented in Exhibit RRL-1.

Response:

The 10.2 miles was selected because it was an even split of the remaining mileage of bare steel and cast iron main over the proposed 8 years for the program.

DISCOVERY REQUEST NO. 69:

Please provide any documentation of meetings or agreements, with TRA Gas Pipeline Safety staff and CGC/AGL Resources personnel since 2003 related to pipeline safety or Bare Steel/Cast Iron Replacement.

Response:

To the best of the Company's knowledge, there is no documentation related meetings or agreements with TRA Gas Pipeline Safety staff since 2003 over pipeline safety or this proposal.

DISCOVERY REQUEST NO. 70:

Provide the number of significant leaks requiring main replacement over the past two years.

Response:

In the past two years, we have responded to 32 leaks on Bare Steel/Cast Iron pipes requiring replacement of short pieces of main.

DISCOVERY REQUEST NO. 71:

Please explain how Areplacement costs≅ are defined in Georgia thus allowing costs to be recovered in the APRP≅ vs. costs associated with Anew business≅.

Response:

The "replacement costs" are the capital costs associated with the individual bare steel and cast iron projects done within the Georgia PRP, so for a job to qualify, it must be principally Bare Steel and Cast Iron and it must be a replacement. It also may not be a highway relocation project since costs for highway relocations are included within base rates. The Company's capital projects in Georgia (and in Tennessee as well) are also separated based on the type of work performed. "New Business" projects are tracked separately from "Mandatory" projects, which is the area where Bare Steel and Cast Iron projects would be tracked, so there is no possibility of recovering "New Business" costs through the PRP.

DISCOVERY REQUEST NO. 72:

Please provide any instances where the Company and the Georgia Commission Audit staff have disagreed on costs available for recovery through the PRP. Provide the dollar amounts of the projects at issue. Explain how the disagreements were resolved.

Response:

Over the eight years of the program, it has been a rare occurrence for the Company and GPSC staff not to reach agreement as to whether a cost should have been in the program or not. In those eight years there have only 3 instances that we have been able to identify where both parties disagreed at the end and in two of those cases, the Company acquiesced and removed the charges, and in the other case the Company petitioned the Commission for a decision since the Company and the Staff could not reach an agreement.

2000 – The Company incurred $18,359 in Contractor downtime charges on Bare Steel/Cast Iron jobs due to permitting problems with the City of Atlanta. The Company believed this cost to be recoverable but consented to the removal of the cost from the program.

2003 – A crew tapped into an abandoned steel main in error when tying in replacement plastic main. This resulted in a second tap and an additional cost of $1,093.36. The company believed the cost to be recoverable but consented to the removal of the cost from the program

2004-2005 – The Company proposed the acquisition of facilities from Southern Natural Gas as part of a comprehensive solution to a couple of proposed large diameter BS/CI renewal projects. This proposal including the acquisition was going to save the ratepayers an estimated $13 Million dollars. The Company and GPSC Staff were in agreement as to the proposed solution but were not in agreement as to whether the acquisition of the facilities should be recoverable under the PRP rider and ultimately the Company went to the Commissioners with that request where they ruled that all of the charges were prudent and a portion of those charges would be recovered through the rider and the remainder would be placed in the Company's rate base in accordance with the requirements of the AGLC Rate Case settlement (Docket 18638-U)

DISCOVERY REQUEST NO. 73:

Please explain how the replacement cost per foot (Exhibit RRL-1) was developed and if the same replacement per foot costs are the same as those projected in Georgia; if not, please explain.

Response:

The cost per foot estimate for Chattanooga was developed based on the Company's knowledge of the facilities to be replaced and the use of historical data for main replacement in the Chattanooga area. The estimated costs per foot are not the same as those in Georgia. Some of the major reasons for differences in the estimated costs per foot are due to differences in individual project size, pipe sizes to be replaced, site conditions and soil conditions.

DISCOVERY REQUEST NO. 74:

Are the Service Metrics included in response to TRA Minimum Filing Guidelines (MFG) #28 being reported to the Tennessee Regulatory Authority at this time? If not, will the Company agree to begin reporting on a monthly basis to both the TRA and the Consumer Advocate Division?

Response:

The metrics as indicated are reported in accordance with the provisions of Minimum Filing Guidelines (MFG) # 28. The Company is committed to providing customers with quality service at just and reasonable rates and will file information the TRA deems necessary in fulfilling its obligation to regulate. During the June 26, 2006 presentation to the TRA, the Company agreed to provide, on a routine basis, certain of the metrics in the future. (See transcript of the June 26, 2006 Presentation by Chattanooga Gas Company Concerning the Shifting of Certain Routine Functions to WIPRO). The Company understands the Authority's concern that the transition to WIPRO does not adversely impact customer service. At this time, the Company is not aware of any systemic customer service issues that the TRA or CAPD is considering other than the transfer of these functions to WIPRO. The Company would expect a request for the reporting of relevant metrics if the TRA or CAPD received significant customer complaints, but again is not aware of any such allegations. Regulatory filings are costly for the Company and require state resources to monitor and should be not be required unless it can be shown that the costs and burden to produce and monitor such reports provide a clear benefit to customers.

DISCOVERY REQUEST NO. 75:

Would CGC agree to begin reporting the same metrics as reported to the Georgia Public Service Commission in compliance with Georgia PSC Docket No. 15295-U, with the frequency as reported there, to the Tennessee Regulatory Authority and the Consumer Advocate Division? If not, please explain why.

Response:

See the Company's response to CAPD No. 74.

DISCOVERY REQUEST NO. 79:

Would the company agree to begin reporting on the following service metrics (if not part of #28 MFG or metrics in compliance with docket 15295-U) detailed below?

A. **Meter Services:**
(1.) Estimates (estimated bills)
(2.) % Estimated Bills
(3.) Skips
(4.) Re-reads
(5.) Door tags (or other means of customer assisted reading)

B. **Construction Departments:**
(1.) Service Orders Received
(2.) Service Orders Installed
(3.) Backlog (Weeks)
(4.) Service Renewal/Relocate (not part of bare steel/cast iron replacement)
(5.) Services Retired

C. **Call Center/Customer Service:**
(1.) Number of Calls Received; % answered[1]
(2.) Answer time
(3.) Length of call (seconds)
(4.) After Call Processing time (%)
(5.) Number of Walk-Ins
(6.) Customer Call Backs
(7.) Supervisory referrals
(8.) Cash Transactions Processed - (Chattanooga)

D. **Service Department:**
(1.) Orders Worked
(2.) Appointment Orders
(3.) Appointments Missed
(4.) Emergency Orders
(5.) Emergency Response time (minutes)

---

[1] "Answered" does not include "busy signal answering"

(6.) Meters Set
(7.) Shut Offs - Non-Payment

Response:

See the Company's response to CAPD No. 74.

DISCOVERY REQUEST NO. 81:

Please explain all management activities taken as the result of TRA Docket 05-00281 attempting to mitigate customer shut-offs for non-payment last winter.

Response:

On October 14, 2005, Chattanooga Gas Company, Nashville Gas Company, a Division of Piedmont Natural Gas Company Inc., and Atmos Energy Corporation filed a Petition before the TRA requesting approval to implement a temporary natural gas billing and service termination mitigation mechanism for the period of November 1, 2005 through March 31, 2006. The petition provided that:

1. All available options and programs to mitigate the seasonal costs of gas or to assist in the payment of natural gas bills for customers experiencing difficulty in making payments this winter, as reflected in each company's existing tariffs, shall remain in effect and be fully available in accordance with their terms.

2. For customer who are in good standing as of November 1, 2005, and who fail or are unable to make full payment of amounts due for natural gas service rendered on or after November 1, 2005, the billing methodology shall be automatically adjusted to an equal payment plan methodology.

3. For customers who are in good standing as of November 1, 2005, and who elect to convert to an equal payment plan or after November 1, 2005, the equal payment plan methodology shall apply.

4. The calculation of monthly amounts due under such equal payment plans methodology shall include any past due balances and shall calculate in conformance with the serving natural gas utility's existing equal payment plan provisions.

5. Notice to the customer of this change in billing methodology shall be provided by bill insert or bill notice in the customer's next monthly bill or by separate written notice.

6. This billing methodology shall continue in effect until October 1, 2006, subject to the customer's ability to opt out of the methodology at any time provided that the customer pays all amounts due for service previously rendered by the serving utility as of that date (or otherwise enters into an arrangement for payment of such amounts acceptable to the serving utility).

7. So long as customers pay the charge due under the equal payment plan methodology, service to such customers will remain in effect and shall not be terminated.

8. To the extent that a customer defaults on payment under the equal payment plans, any unpaid gas cost amount shall be collected consistent with the methodology established in TRA docket 03-00209.

The utilities also agreed to amend their tariffs to provide that no service terminations will occur during any 24 hour period, as measured from 8:00 am on the planned day of termination, where forecasted low temperature, as determined by the Natural Weather Service, is 32 degrees Fahrenheit or below.

At the regularly scheduled TRA Conference held on November 7, 2005 Chairman Ron Jones, Director Pat Miller, and Director Sara Kyle voted unanimously to grant the Petition and approved the proposed tariff revision effective November 7, 2005. (See Authority April 19, 2006 Order in Docket 05-00281.)

In order to implement the provisions of the Petition approved by the TRA, Chattanooga Gas Company management prepared and filed on October 19, 2005 the revised tariff provision addressing termination of service for no payment when the forecasted low temperature is 32° F or below during the following 24 hours measured from 8:00 am on the planned day of termination. (Since the Company had previously adopted the policy consistent with the revised tariff provision, no modifications of operating procedures were required as a result of the tariff provision.)

Management also developed and implemented procedures:

1) that provided for customers in good standing as of November 1, 2005 who failed or were unable to make full payment of amounts due for natural gas service rendered on or after November 1, 2005 to be automatically placed on an equal payment plan;

2) that provided for customers in good standing as of November 1, 2005 to voluntarily be placed on equal payment plans that included and include amounts due at the time of the election;

3) to provide each customer placed on an equal payment plan a letter of explanation of the payment plan;

4) to capture and report for each month:

   a. the number of residential customers whose service was terminated

for non-payment during the preceding calendar month;

b. the number of residential customers whose service was terminated for non-payment during the same calendar month of the prior year;

c. the number of residential customers participating in the company's equal payment plan during the preceding calendar month; and

d. the number of residential customers participating in the company's equal payment plan during the same calendar month of the prior year.

In addition to the provision addressed in the October 14, 2005 Petition and the April 19, 2006 Order, CGC management also developed and made available to customers contact information for agencies that provide assistance to customers who had difficulty in paying their gas bill. These agencies were:

First Call for Help

Human Services

Ladies of Charity

Salvation Army

Northside Neighborhood House

Metropolitan Ministry, and

Hamilton County Social Services.

This information was made available at the Call Center, provided to Company employees on a 3.5 X 6.5 inch cards to be given to customers, and posted on the Company's Website.

Also posted on the Company's Website and included with billing information were directions for customers needing assistance to call 211 for the United Way hotline.

In addition to these actions by CGC management, during 2005 the AGLR Foundation donated to the Departments of Human Services of Hamilton and Bradley Counties respectively $45,000 and $5,000 to be used for low income energy assistance.

The Company also continued its participation in the "Warm Neighbors" program collecting $13,489 during the period of November 2005 through August 2006. The funds, contributions from CGC customers, were provided to the United Way for distribution.

DISCOVERY REQUEST NO. 99:

According to the June presentation, Wipro was chosen based on the following :

(a) Strong quality program - Six Sigma, Lean Sigma - please explain in detail what "Six Sigma, and Lean Sigma" mean and how this compares to U.S. companies;

Response:

Wipro's definition of Six Sigma is a management philosophy that uses customer-focused goals and measurements to drive continuous improvement at every level of an enterprise. Its focus on the process—as opposed to product—differentiates Six Sigma from other programs. This focus helps to provide the measurable results. More than a philosophy, Six Sigma represents an attitude, a set of tools, a planned sequence of steps, and a level of commitment to excellence that is the surest road to profitability. Because the philosophy must be embraced throughout the organization, Six Sigma requires leadership and commitment from top management.

The website, www.isixsigma.com, defines Six Sigma as "a disciplined, data-driven approach and methodology for eliminating defects (driving towards six standard deviations between the mean and the nearest specification limit) in any process -- from manufacturing to transactional and from product to service. The fundamental objective of the Six Sigma methodology is the implementation of a measurement-based strategy that focuses on process improvement and variation reduction through the application of Six Sigma improvement projects. This is accomplished through the use of two Six Sigma sub-methodologies: DMAIC and DMADV. The Six Sigma DMAIC process (define, measure, analyze, improve, control) is an improvement system for existing processes falling below specification and looking for incremental improvement. The Six Sigma DMADV process (define, measure, analyze, design, verify) is an improvement system used to develop new processes or products at Six Sigma quality levels. It can also be employed if a current process requires more than just incremental improvement. Both Six Sigma processes are executed by Six Sigma Green Belts and Six Sigma Black Belts, and are overseen by Six Sigma Master Black Belts."

Wipro employs

- 100 full time six sigma black belts
- 700 six sigma green belts
- All associates 'kaizen' trained (Small, incremental improvements – used in conjunction with Six Sigma - Focus is on implementing small ideas without any investments)
- More than 3000 'kaizen' s implemented by employees

According to www.georgegroup.com's summary of the book "What is Lean Six Sigma?", Lean Six Sigma combines the two most important improvement trends of our time: making work better (using Six Sigma) and making work faster (using Lean principles).

Lean Six Sigma, as Wipro defines it, is the application of lean techniques to increase organizational speed, while combining the tools and culture of Six Sigma to improve efficiencies and focus on customers' issues. The principles of Lean Six Sigma are to initially work on causes of customer critical-to-quality issues and those that create the longest lead-time delays in any process. Eliminating those causes provides the greatest opportunity for improvement in cost, quality, capital, and lead-time.

Both Six Sigma and Lean Six Sigma are used in many U.S. companies, including AGL Resources. Wipro, along with another Indian vendor, specifically referred to the use of Six Sigma and Lean Six Sigma within their operations when responding to the Request for Proposal that AGL Resources sent out for business process outsourcing.

(b) "Experts in Call Center Industry with World Class Clients" - please explain value to the utility consumer versus Georgia Call Center previously utilized;

Response:

Wipro

- Is the largest third party business process outsourcing company in India
- has14 clients among Fortune 500 (as of March 31st , FY 2004 - 05)
- has the largest breadth of services from customer relationship management to

back office transaction processing & industry specialized services

- has 95 + processes in production; handling 7 million transactions (voice and back office) per month
- has state-of-the-art centers in seven cities New Delhi, Mumbai, Belapur, Chennai, Pune, Kolkata & Bangalore.
- provides extensive cultural, language and process skills training to associates
- maintains robust telecom infrastructure for managing voice & data communication

Unlike Wipro, the Georgia call center has one location in Riverdale, Georgia that provides service only to the utilities owned and operated by AGL Resources. The expertise of the employees at the Riverdale call center is based primarily on experience and training received from other call centers. In contrast as identified above Wipro provides call center services for many different companies across many different industries and is able to leverage the best practices from these experiences to all of their customers. The scale of its operations allows Wipro to utilize the most efficient technology, and develop and implement the most efficient processes and training programs. In addition the multiple sites that Wipro owns and operates affords a different and higher level of disaster recovery planning than is currently in place at the Georgia call center.

(c) Solid Training Programs - please explain differences versus previous Call Center in Georgia; and

Response:

Wipro employee training includes:

- Introduction to Wipro BPO
- Vision, culture, mission training
- Wipro BPO values and functions
- Quality awareness
- Bridging cultural gaps
- Effective communication
- Voice-accent neutralization
- Industry overview
- Overview of customer systems, etc
- Process-specific knowledge and skills
- Systems and process skills
- Buddy system
- Shadowing
- Live calls and / or Transactions

Some of these processes are in place at Wipro to address cultural differences between

the U.S. and India and therefore are not necessary for the Georgia call center. The significant difference between the Georgia call center and Wipro's training is that Wipro has in place established processes and programs to address ongoing training needs for both current and future employees. This type of training is not a core competency at the AGL Resources call center in Georgia. In addition, Wipro operates a call center support company – which creates many upward growth opportunity for all employees allowing the company to attract diverse talent. In contrast AGL Resources' call center is a small operation within a much larger non-call center operation. This limits the opportunity of call center employees for upward career growth within the call center environment and does not allow for recruiting and retention of as diverse a workforce.

(d) Employees - (education and availability) Please explain versus U.S. Companies.

Response:

While Wipro employees are only required to have an equivalent High School education, many are college graduates, and many that have not earned a degree have taken college level courses. In addition, the applicant pool is tremendous allowing the company to select only the best qualified. Wipro received 3,500 applications for 80 posted positions for AGL Resources.

Currently, the call center employees have an equivalent High School education, but very few have taken college level courses or earned degrees. In contrast to high number Wipro's applicants, AGL Resources has been unable to attract a sufficient level of qualified applicants, and as a result has used temporary agencies to obtain appropriate staffing.

DISCOVERY REQUEST NO. 106:

Please detail all company plans to communicate Call Center operations issues with the TRA and the Consumer Advocate Division through transition from the current operation

Response:

All call center performance metrics are available for review with the TRA and/or the Consumer Advocate Division