filed electronically in docket office on 06/24/08

IN THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF TENNESSEE AMERICAN	)	
WATER COMPANY TO CHANGE AND	)	
INCREASE CERTAIN RATES AND	)	
CHARGES SO AS TO PERMIT IT TO	)	**DOCKET NO. 08-00039**
EARN A FAIR AND ADEQUATE RATE	)	
OF RETURN ON ITS PROPERTY USED	)	
AND USEFUL IN FURNISHING WATER	)	
SERVICE TO ITS CUSTOMERS	)	
	)	

SUPPLEMENTAL RESPONSES OF THE CONSUMER ADVOCATE AND PROTECTION DIVISION TO THE FIRST DISCOVERY REQUEST OF TENNESSEE AMERICAN WATER COMPANY

Robert E. Cooper, Jr., Attorney General and Reporter for the State of Tennessee, by and through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate"), hereby submits these supplemental response to the first discovery request of Tennessee American Water Company ("TAWC" or "Company"):

DISCOVERY REQUEST NO. 2:

Identify all persons known to you, your attorney, or other agent(s) who have knowledge, information or possess any document(s) or claim to have knowledge, information or possess any document(s) which support your answer to Discovery Request No. 1 above.

SECOND SUPPLEMENTAL RESPONSE:

The Consumer Advocate's investigation of this matter is ongoing. Based on the Consumer Advocate's preliminary investigation, the Consumer Advocate identifies the following TAWC customers who may have knowledge, information or documents relevant to the issues pending in this

matter: (1) the industrial customers of TAWC, who are specifically identified in TAWC's supplemental response to Part IV, Question No. 5 of the Consumer Advocate's first discovery request; and (2) the resale customers of TAWC, who are specifically identified in TAWC's supplemental response to Part IV, Question No. 6 of the Consumer Advocate's first discovery request. The Consumer Advocate reserves the right to identify additional persons who may have knowledge, information or documents relevant to the issues pending in this matter as its investigation continues.

DISCOVERY REQUEST NO. 4:

Identify any person you intend to call as a fact or expert witness (including, but not limited to, the persons referred to in paragraph 4 of your "Joint Objection of the Intervenors To Discovery Question Limits for the Initial Round of Discovery," in which you refer to "two outside consultants hired by the Consumer Advocate to respond to the Company's revenue and depreciation witnesses"), the subject matter of the witness' testimony, the substance of the facts and opinions to be expressed and the basis and reasons therefor, the data, documents, materials or other information shown to, relied upon, created by or considered by the witness as part of this case and/or as a basis in forming his or her opinions, any exhibits to be used as a summary of or support for each such opinion, the qualifications of the witness, including a full resume, a list of all publications authored by the witness, the compensation to be paid for the study and testimony, and a listing of any other cases in which the witness has testified at trial or by deposition.

SECOND SUPPLEMENTAL RESPONSE:

The Consumer Advocate's investigation of this matter is ongoing. Based on the Consumer Advocate's preliminary investigation, the Consumer Advocate has determined that it may call the

following expert witnesses :

Robert T. (Terry) Buckner may testify to the following subject matters: Ratemaking Theory, Principles and Practices; Accounting, including, but not confined to: Revenues, Employee Compensation and Benefits, Other Operations and Maintenance Expenses, Depreciation, Management Fees, Other Taxes, Income Taxes, and Rate Base; Revenue Requirements; Cost of Service; Value of Service; and Rate Design. Mr. Buckner is a regulatory analyst on the staff of the Consumer Advocate. Information regarding Mr. Buckner's qualifications is attached.

Stephen N. Brown may testify to the following subject matters: Capital Structure; Cost of Capital; Cost of Service; and Rate Design. Dr. Brown is an economist on the staff of the Consumer Advocate. Information regarding Dr. Brown's qualifications is attached.

Michael D. Chrysler may testify to the following subject matters: Customer Service and Value of Service. Mr. Chrysler is a regulatory analyst on the staff of the Consumer Advocate. Information regarding Mr. Chrysler's qualifications is attached.

Charles W. King may testify to the following subject matters: Depreciation; Weather Normalization Adjustments; and Management Fees. Mr. King is an independent consultant retained by the Consumer Advocate for this proceeding. Information regarding Mr. King's qualifications and compensation was previously provided to the Company on May 28, 2008.

Michael J. Majoros, Jr. may testify to the following subject matters: Depreciation; Weather Normalization Adjustments; and Management Fees. Mr. Majoros is an independent consultant retained by the Consumer Advocate for this proceeding. Information regarding Mr. Majoros' qualifications and compensation was previously provided to the Company on May 28, 2008.

Glynn Stoffel may testify to the following subject matters: Depreciation; Weather

Normalization Adjustments; and Management Fees. Mr. Stoffel is an independent consultant retained by the Consumer Advocate for this proceeding. Information regarding Mr. Stoffel's qualifications and compensation was previously provided to the Company on May 28, 2008.

As of this date, the Consumer Advocate has not determined the substance of the facts and opinions to which each expert is expected to testify. The Consumer Advocate reserves the right to identify additional expert witnesses and additional subject matters on which it may offer testimony as its investigation of this matter continues.

RESPECTFULLY SUBMITTED,

RYAN L. McGEHEE
Assistant Attorney General
Office of the Attorney General and Reporter
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, TN 37202-0207

Dated: June 23, 2008

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing is being served via U.S. Mail and/or electronic mail upon:

R. Dale Grimes, Esq.
Ross Ian Booher, Esq.
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1600 Division Street, Suite 700
Nashville, TN 37203

This the 23 day of June, 2008.

RYAN L. McGEHEE
Assistant Attorney General

#121006

APPENDIX A

MICHAEL CHRYSLER:

EXPERT WITNESS QUALIFICATIONS & PRIOR TESTIMONY AND PUBLICATIONS

Regulatory Analyst

Education:

Bachelor of Business Administration (Accounting)

Ft. Lauderdale University, 1970

TN AG (Consumer Advocate & Protection Division) 1998-Present

Provided analysis in Energy and Water issues, rate cases as assigned

Active in analysis related to Consumer Protection telephone issues

Testified in Docket No. 02-00383 Petition of Chattanooga Gas Company For Approval of Change in Purchased Gas Adjustment

Testified in Docket No. 03-00118 Petition of Tennessee-American Water Company To Change And Increase Certain Rates and Charges

Testified In Docket No. 03-00313 Application of Nashville Gas Company, a Division of Piedmont Natural Gas Company, Inc. for an Adjustment of its Rates and Charges, the Approval of Revised Tariffs and the Approval of Revised Service Regulations

Testified in Docket No. 04-0034 Petition of Chattanooga Gas Company for Approval of Adjustment of its Rates and Charges and Revised Tariff

Testified in Docket No. 04-00288 Petition of Tennessee American Water Company to Change and Increase Certain Rates and Charges So as to Permit it to Earn a Fair and Adequate Rate of Return on its Property Used and Useful in Furnishing Water Service to its Customers.

Testified in Docket No. 05-00258 Petition of the Consumer Advocate to Open an Investigation to Determine Whether Atmos Energy Corp. Should Be Required by the Tennessee Regulatory Authority to Appear and Show

Cause That Atmos Energy Corp. Is Not Overearning in Violation of Tennessee Law and That it Is Charging Rates That Are Just and Reasonable

Testified in Docket No. 06-00175 Petition of Chattanooga Gas Company to Increase Rates, Including a Comprehensive Rate Design Proposal and Revised Tariff

Testified in Docket No. 06-00290 Petition of Tennessee American Water Company to Change and Increase Certain Rates and Charges So as to Permit it to Earn a Fair and Adequate Rate of Return on its Property Used and Useful in Furnishing Water Service to its Customers

Testified in Docket No. 07-00105 Petition of Atmos Energy Corporation For Approval of a General Rate Increase

- Internet Links to Testimony provided on following pages

NRRI Research Advisory Committee (Natural Gas Issues) Present

Chairman of NASUCA's Consumer Protection Committee 2004-Present

NASUCA Committee Resolutions contributed to by Mike Chrysler (copies attached):

- *Energy Conservation and Decoupling Resolution* - sponsored
- *High Winter Energy Costs Resolution* regarding LIHEAP funding - sponsored
- *Uncollectible Accounts Resolution* regarding for State Authority's to resist expansion of definition - sponsored
- *Minimum Service Quality Standards Resolution* calling for regular reporting and industry standards - sponsored
- *Infrastructure Surcharge Resolution* calling for annual tracking adjustments - contributor

Northern Indiana Public Service Company (NISOURCE) 1973-1997

Principal of Electric Business Planning: Electric Business Planning Department (1990-1997)

Coordinated $147 million Capital, $101 million Expense, and $789 million Margin budget development of The Electric Business, with subsequent monthly/quarterly explanation of variances reported to Senior Management.

C Provided consulting assistance to station/district planners for proper explanation of their Capital

& Expense variances to Senior Management, then summarized for reporting.

- Assisted with O&M and Capital Budget ABM training (budget development and data entry in budgeting system); plus proper development of budgets for presentation and approval.
- Provided Electric Margin variance analysis by class on a monthly/quarterly basis to Senior Management.
- Developed a sophisticated computer model for the Director of Electric Production in Microsoft Excel, providing "what if" analysis along with historical data to reach a goal of $16 per megawatt hour generation cost goal.
- Assisted the Vice President and General Manager, Electric Business in the development of written speeches as well as corresponding presentation slides.

Senior Consultant: Corporate Consulting Services (1989-1990)

Responsible for providing expertise and assistance to various departments within the company, including training of management personnel on various productivity seminars and software programs.

- Researched "under-billing" of NIPSCO gas customers due to the variable of "Supercompressibility." Quantified over $200,000 of annual under-billing for the gas metering department.
- Interviewed NIPSCO management personnel to ensure compliance with "Automatic Time Reporting" program for Human Resources Department.

Senior Strategic Planning Analyst: Corporate Strategic Planning Department (1985-1989)

Responsible for providing top-down, bottom-up communication of the Corporate Strategic Plan to all management levels.

- Assisted in the development, coordination of data and reporting of meaningful performance measures to Senior Management for each business unit.

- Assisted management employees with the training classes “Business Strategies” and “Operations Strategies.’ This assistance included ensuring appropriate workbase study, drafting of the company strategic plan, involvement and understanding of principles and strategies in making business decisions to be entered in case studies and computer simulations.

Senior Rate Analyst: Rate and Contract Department (1978-1985)

Responsible for supporting rate case development, and associated work papers and supporting materials for Case-In-Chief. Provided tracking updates, reflecting modification to rate filings until subsequent filing.

- Prepared filing and exhibits for purchase gas adjustment, fuel cost adjustment, purchase power tracking adjustments with the Indiana PSC/IURC
- Audited large gas and electric industrial bills prior to release on a monthly basis
- Billed large industrial gas and electric customers during union contract negotiations (approximately 60% of company revenue). Customers included U.S. Steel, Inland and Bethlehem Steel.
- Assisted in the preparation of testimony and exhibits for regulatory hearings.

Junior Accountant: Customer Accounting Department (1973-1978)

Responsible for communicating corporate billing and office procedures to district commercial offices. Provided special data analysis regarding billing to corporate accounting.

- Provided vacation relief for district office managers. These responsibilities included supervision of meter readers, application credit, billing and cash representatives.
- Calculated source reports and reported to Accounting Department including gas cost, fuel cost,
- purchase power adjustment and other revenue amounts on a monthly basis.

Internet Links to Expert Testimony of Michael D. Chrysler on behalf of CAPD

TRA Docket 07-00105

IN RE: PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF A GENERAL RATE INCREASE

Direct Testimony Filed 8/22/07: http://www2.state.tn.us/tra/dockets/0700105.htm

TRA Docket 06-00290

IN RE: PETITION OF TENNESSEE AMERICAN WATER COMPANY TO CHANGE AND INCREASE CERTAIN RATES AND CHARGES SO AS TO PERMIT IT TO EARN A FAIR AND ADEQUATE RATE OF RETURN ON ITS PROPERTY USED AND USEFUL IN FURNISHING WATER SERVICE TO ITS CUSTOMERS

Direct Testimony Filed 3/5/07: http://www.state.tn.us/tra/orders/2006/0600290ca.pdf

TRA Docket No. 05-00258

IN RE: PETITION TO OPEN AN INVESTIGATION TO DETERMINE WHETHER ATMOS ENERGY CORPORATION SHOULD BE REQUIRED BY THE TRA TO APPEAR AND SHOW CAUSE THAT ATMOS ENERGY CORPORATION IS NOT OVEREARNING IN VIOLATION OF TENNESSEE LAW AND THAT IT IS CHARGING RATES THAT ARE JUST AND REASONABLE

Direct Testimony filed 7/17/06: http://www.state.tn.us/tra/orders/2005/05258by.pdf

TRA Docket 04-00034

IN RE: PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND CHARGES AND REVISED TARIFF.

Direct Testimony filed 7/26/04: http://www.state.tn.us/tra/orders/2004/0400034dn.pdf

TRA Docket 04-00288

IN RE: PETITION OF TENNESSEE AMERICAN WATER COMPANY TO CHANGE AND INCREASE CERTAIN RATES AND CHARGES SO AS TO PERMIT IT TO EARN A FAIR AND ADEQUATE RATE OF RETURN ON ITS PROPERTY USED AND USEFUL IN FURNISHING WATER SERVICE TO ITS CUSTOMERS.

Direct Testimony filed 12/3/04: http://www.state.tn.us/tra/orders/2004/0400288bl.pdf

TRA Docket 03-00313

IN RE: APPLICATION OF NASHVILLE GAS COMPANY, A DIVISION OF PIEDMONT NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF ITS RATES AND CHARGES, FOR APPROVAL OF REVISED TARIFFS AND APPROVAL OF REVISED SERVICE REGULATIONS.

Direct Testimony filed 8/18/03: http://www.state.tn.us/tra/orders/2003/0300313x.pdf

TRA Docket 03-00118

IN RE: PETITION OF TENNESSEE AMERICAN WATER COMPANY TO CHANGE AND INCREASE CERTAIN RATES AND CHARGES SO AS TO PERMIT IT TO EARN A FAIR AND ADEQUATE RATE OF RETURN ON ITS PROPERTY USED AND USEFUL IN FURNISHING WATER SERVICE TO ITS CUSTOMERS.

Direct Testimony filed 5/30/03: http://www.state.tn.us/tra/orders/2003/0300118bo.pdf

TRA Docket 02-00383

IN RE: PETITION OF CHATTANOOGA GAS COMPANY FOR APPROVAL OF CHANGE IN PURCHASE

GAS ADJUSTMENT
Direct Testimony filed 5/21/03: http://www.state.tn.us/tra/orders/2002/0200383m.pdf

THE NATIONAL ASSOCIATION OF
STATE UTILITY CONSUMER ADVOCATES
RESOLUTION 2007-01

NASUCA ENERGY CONSERVATION AND DECOUPLING RESOLUTION

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed

return; rather, earnings depended on capable management operating the utilities in an efficient manner;

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA: Submitted by:

Denver, Colorado NASUCA Consumer Protection Committee

June 12, 2007 June 11, 2007

120302/Chrysler-Direct/07-00269

The National Association of State Utility Consumer Advocates
Resolution 2005-03

INFRASTRUCTURE SURCHARGE RESOLUTION

Calling upon state regulatory authorities and legislatures to refuse to allow, or to consider revoking, annual tracking adjustments to rates resulting from additional non-traditional gas, water, sewer or electric infrastructure replacement programs;

Whereas, traditional ratemaking methodologies have allowed investor shareholders to earn a return on new and upgraded mains and electric plant through general rate case reviews allowing the ratepayers being charged for the prudent and necessary system upgrades to be represented in traditional contested rate proceedings in which all items of expense and capital investments are considered; and

Whereas, depreciation provides a "funding" mechanism for natural gas, water, sewer, and electric plant replacement because it reduces net operating income and increases the revenue required from rate payers for an acceptable rate of return during the formal rate proceeding; and

Whereas, traditional ratemaking processes have withstood the test of time, so that all parties represented have an opportunity to have their interests fairly represented; and

Whereas, parties representing the interests of shareholders and company managements may propose "short-circuit" methods focused on single categories of increased expense, in order to "speed up" the recovery of costs outside the normal regulatory process, and to provide regulators ways to avoid the rate review process; and

Whereas, utilities in several states have proposed, either in rate cases or as state legislation, various "tracking methodologies" which, if allowed, would enable them to increase rates through non-traditional ratemaking processes sometimes called DSIC (Distribution System Improvement Charge), DSR (Distribution System Replacement), AMRP (Accelerated Main Replacement Program) PRP (Pipeline Replacement Program) which would allow immediate rate recovery of capital investment for new projects on a year-by-year basis in order to replace certain rate base

infrastructure through a surcharge; and

Whereas, if such tracking methodologies were allowed, regulatory authorities may not be able to review such capital investments for prudence, and may not be able to review possible offsetting contemporaneous cost reductions or revenue increases from other utility activities; and

Whereas, if such tracking methodologies are allowed ratepayers will become involuntary investors paying for unreviewed investments that will increase rates;

Whereas, at a time of rising commodity costs, regulators need to understand the potential significant new burden upon consumers caused by a tracking surcharge for plant additions;

THEREFORE BE IT RESOLVED, that NASUCA calls upon state regulatory authorities and legislators to refuse to impose on consumers, or to consider revoking, non-traditional infrastructure surcharges that would increase natural gas, water, sewer or electric utility bills without traditional opportunity for consideration of countervailing cost decreases and revenue increases, and review by all parties including appropriate consumer advocacy offices prior to implementation and to remain committed to traditional ratemaking principles fairly representing the interests of both consumers and stockholders.

BE IT FURTHER RESOLVED, that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
June 12, 2005

Approved by NASUCA

Place: New Orleans, LA
Date: June 14, 2005 91974

The National Association of State Utility Consumer Advocates
Resolution 2005-04
MINIMUM SERVICE QUALITY STANDARDS RESOLUTION

Calling upon state regulatory authorities to establish regular reporting requirements for utilities on service quality and to establish minimum performance standards with appropriate enforcement provisions so that adequate, reliable, and safe service is achieved and maintained; and

Whereas, adequate service quality from providers of gas, electric, water, and telecommunications services is essential to everyday life and affects almost every function of our society, and service inadequacies and interruptions frustrate or disrupt normal functions; and

Whereas, adequate service quality from such providers is also vital to our Nation's economy, our position in the global economy and to national security;

Whereas, gas, electric, water, and telecommunications service providers have a duty to provide service that is adequate, reliable, and safe; and

Whereas, consumers expect and should receive service that is consistently adequate, reliable, and safe; and

Whereas, utility industry developments over the past decade such as mergers, diversification, and changing economic conditions have encouraged utilities to cut costs, reduce staffs and outsource some utility operating functions, and such efforts to economize may have led to deterioration of service quality; and

Whereas, a gradual decline in performance may not be detected for some time if regulators do not keep informed as to service quality through regular monitoring; and

Whereas, by keeping informed, regulators are better able to recognize signs of deterioration and inadequacies so that they can take corrective action to avert major service quality problems that would otherwise be frustrating and disruptive to consumers; and

Whereas, standardized reporting requirements and regular reporting are necessary for regulators to be able to monitor service quality and changes in performance; and

Whereas, reports should address performance areas such as customer relations and billing (e.g., responsiveness of customer call centers, responsiveness to consumer complaints, timeliness of installations and repairs, and accuracy and frequency of billing and meter reading) and operating performance (e.g., frequency and duration of outages, and responsiveness to safety calls); and

Whereas, reporting requirements should be carefully designed to yield accurate data that is uniform and consistent; and

Whereas, in addition to keeping informed about service quality, regulators should establish measurable performance standards that must be met for providers to achieve and maintain a minimum quality of service, to the extent that quality of service is measurable, so that expectations are clear and problems are minimized; and

Whereas, performance standards should be supported by appropriate enforcement provisions; and

Whereas, service quality data and information should be available to the public to encourage companies to achieve good performance results, to assure that regulation is open and effective and to assist consumers who must choose among competitive providers;

THEREFORE BE IT RESOLVED, that NASUCA calls upon state regulatory authorities to establish regular service quality reporting requirements applicable to gas, electric, water, and telecommunications service providers, and to establish minimum performance standards with appropriate enforcement provisions to monitor and promote improvement toward a consistently high level of service quality for their gas, electric, water, and telecommunications customers.

BE IT FURTHER RESOLVED, that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
June 12, 2005

Approved by NASUCA:
Place: New Orleans, LA
Date: June 14, 2005 91972

120302/Chrysler-Direct/07-00269

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES NASUCA

RESOLUTION

Calling Upon State Regulatory Authorities to resist the efforts of Local Gas Distribution Companies to expand the interpretation of gas cost to include a calculated portion of their uncollectible accounts expense or other non-gas costs in purchased gas cost recovery mechanisms.

Whereas, many natural gas Local Distribution Companies (LDCs) are permitted by State laws or regulations to change rates from time to time to track changes in the cost of natural gas supply and transportation through gas cost adjustments without a review of general rates;

Whereas, many such gas cost adjustment mechanisms provide for the periodic adjustment of rates to true up the difference between gas costs billed to consumers and gas costs incurred;

Whereas, the gas cost adjustment mechanisms have been found justified due to characteristics of the costs associated with purchasing and transporting gas to an LDC's distribution system; i.e., that such cost may make up a sizable portion of the total rate for natural gas service, that such costs are affected by many market conditions that are not within the control of the LDC, that such gas costs are volatile and may change significantly in a short time;

Whereas, some State regulatory authorities have been petitioned by LDCs to broaden the sort of expenses that may be recovered through gas cost adjustment mechanisms to include a portion of the expenses associated with uncollectible charges experienced by the LDC;

Whereas, the characteristics of uncollectible accounts are materially different from gas costs; i.e., while they are somewhat affected by variations in rates caused by changes in gas costs, uncollectible accounts expenses do not make up a sizeable portion of the total rate for natural gas service, they are affected by factors such as staffing and procedures within the control of the LDC, and the changes in uncollectible costs do not tend to be volatile;

Whereas, an expanded definition of gas costs would shift more risk to ratepayers and may remove traditional or performance based incentives for utilities to minimize costs;

THEREFORE BE IT RESOLVED, that NASUCA encourages state regulatory authorities to limit the use of gas cost adjustment mechanisms to the cost of purchasing and transporting natural gas supply to the LDC's distribution system.

120302/Chrysler-Direct/07-00269

BE IT FURTHER RESOLVED, that the Gas Committee of NASUCA, with the approval of the Executive Committee of NASUCA, is authorized to take all steps consistent with this Resolution in order to secure its implementation.

Submitted by:

June, 15, 2004

Approved by NASUCA 91970

NASUCA RESOLUTION
HIGH WINTER ENERGY COSTS RESOLUTION

WHEREAS the cost of home heating energy has always burdened low income households disproportionately compared with households of all other income levels; and

WHEREAS one of the most effective means of measuring this disparity is to evaluate the energy burden of a household by dividing the cost of home energy by the gross income of the same household to determine the percentage of income needed to meet energy costs; and

WHEREAS in 2005, the National Energy Assistance Directors Association ("NEADA") determined that all low-income households used, on average, 15% of their gross household income for energy costs (6% for heat alone), while all households used, on average, only 3% of their gross household income for energy costs (1% heat alone); and

WHEREAS in 2004, elderly households in receipt of Supplemental Security Income paid nearly 19% of their income for energy, and households in receipt of Aid to Families with Dependent Children paid 26% of their income for energy; and

WHEREAS the Energy Information Administration ("EIA") has forecast dramatic increases in the cost of energy which will have an immediate and deleterious short term effect on the already disproportionate energy burden on low-income households; and

WHEREAS, based on EIA data from September 2005, the average family heating with oil could spend as much as $1,666 during the winter of 2005-2006. This would represent an increase of $403 over the costs for the winter of 2004-2005 and an increase of $714 over the costs for the winter of 2003-2004; and

WHEREAS the EIA anticipates that heating fuel expenditure increases from the winter of 2004 to the winter of 2005 are likely to average 73% for natural gas in the Midwest; 19% for electricity in the South; 31% for heating oil in the Northeast; and 41% for propane in the Midwest; and

WHEREAS, the Center on Budget and Policy Priorities ("CBPP"), an independent, bipartisan research institute, calculated (http://www.cbpp.org/10-6-05bud.htm) that the average low income household (income below the greater of 150% of the federal poverty guidelines or 60% of

the state median income) will incur an average heating bill increase of $500 for the 2005-2006 winter; and

WHEREAS the easily predictable outcome of the combination of the extreme energy burden currently facing low-income households and the anticipated increase in home energy costs is the creation of a "perfect storm" which will result in an unparalleled challenge to the energy safety net below low-income households; and

WHEREAS these increased costs for home energy during the winter of 2005-2006 were predicated on the foreseeable actions in the marketplace based upon historically accurate and verifiable facts, factors, formulae and information; and

WHEREAS short-term and long-term effects of Hurricanes Katrina and Rita including the damage and destruction to the production, storage, transportation and infrastructure of the natural gas and crude oil industries, and the resulting escalation of home energy costs as a result of the depletion of reserves and the inability of the industries to quickly recover from the devastation remains to be calculated; and

WHEREAS the severe constraints on state and local government budgets already strain the ability of those entities to reinforce the low income safety net; and

WHEREAS the nonprofit, faith-based, and other community-based organizations, secondarily charged with the task of assisting low-income households with problems such as the imminent energy crisis are similarly constrained by limited resources and increasing energy costs; and

WHEREAS the Low Income Home Energy Assistance Program ("LIHEAP") is a federally-funded, state-administered energy plan designed to provide funding to the states to assist low-income households in meeting the costs of home energy; and

WHEREAS since the winter of 2001-2002, the national appropriation for LIHEAP has wholly failed to match the pace of the increase in home heating costs; and

WHEREAS the anticipated funding for the 2005-2006 LIHEAP Year fails to keep pace with inflation and would fail to be even minimally adequate to compensate for the anticipated spikes in home energy and home heating energy now predicted by the EIA; and

WHEREAS in 2005, NEADA determined that LIHEAP funding between the 2001-2002 and 2004-2005 fiscal year increased by 21.4%, but the share of a low-income households' heating expenditures met by the average LIHEAP grant fell from 49.4% to 25.2% for heating oil, from 52.3% to 33.4% for natural gas, and from 35.5% to 23.1% for propane; and

WHEREAS in 2005, NEADA determined that between 2001-2002 and 2004-2005 the price of oil for heating increased by $624, and the price of natural gas for heating increased by $352, and the price of propane for heating increased by $489, yet, the average LIHEAP grant increased by $3; and

WHEREAS, according to the EIA, while the average cost of home heating fuel for the coming winter may rise precipitously: heating oil by 98%, propane by 55%, and natural gas by 58%, the national appropriation for LIHEAP, since the winter of 2001-2002, has risen by only about 20%; and

WHEREAS the proposed 2005-2006 executive federal budget appropriation called for a decrease in funding of approximately $250 million with no emergency contingency funding; and

WHEREAS the House of Representatives Labor-HHS-Education Appropriations Committee has proposed FY 2006 LIHEAP funding at $2.006 billion in regular funding and no emergency contingency funding; and

WHEREAS the Senate Appropriations Committee has proposed FY 2006 LIHEAP funding at $1.8 billion in regular funding and $300 million in emergency contingency funding; and

WHEREAS the CBPP calculates that, in order to maintain 2005-2006 LIHEAP purchasing power, taking into consideration general inflation, at the same level as 2004-2005 LIHEAP, the national appropriation should increase to $3.025 billion; and

WHEREAS the CBPP calculates that a mere 5% increase in the number of eligible applicants for LIHEAP assistance would require additional national 2005-2006 LIHEAP funding in the amount of $150 million; and

WHEREAS the CBPP calculates that to hold beneficiaries of LIHEAP assistance harmless in the face of the entire expected price increase would require additional 2005-2006 LIHEAP funding in the amount of $2.033 billion; and

WHEREAS the CBPP calculates that the total minimum federal appropriation required for the 2005-2006 LIHEAP is $5.208 billion; and

WHEREAS LIHEAP remains a targeted block grant program with the built-in flexibility and an established federal-state partnership to effectively and efficiently deliver the funding necessary to ease the crisis on increasingly unaffordable energy costs for low-income households; and

WHEREAS the current appropriations and proffered amendments clearly are insufficient to deal with the anticipated increases in home energy costs; *now therefore be it*

RESOLVED that NASUCA urges Congress to appropriate FY 2006 LIHEAP regular funding of at least $5.208 billion, as recommended by CBPP, and to appropriate an additional $500 million for emergency contingency funding to assist low-income households in meeting the exorbitant home energy costs anticipated for the winter of 2005-2006; and

BE IT FURTHER RESOLVED that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The

Standing Committees or the Executive Committee shall notify the membership of any action taken to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
November 16, 2005

Approved by NASUCA 91969

Steve Brown, Economist

B. A. in History, Colorado State University

Ph.D. and M.A. in International Relations with a specialty in International Economics. University of Denver

M.S. in Regulatory Economics, University of Wyoming

Twenty-eight years of experience with the Public Utility industry:

1979 - 1982	Tri-State Generation and Transmission Association - Power Requirements Supervisor & Rate Specialist
1982 - 1984	Arizona Electric Cooperative - Rate Analyst
1984 - 1986	Houston Lighting & Power - Supervisor of Rate Design
1986 - 1995	Iowa Utilities Board - Chief of the Bureau of Energy Efficiency- Auditing, Research & Utilities Specialist
1995 - Present	Office of the Attorney General for the State of Tennessee - Consumer Advocate and Protection Division - Economist

Dockets & Testimony

Dr. Brown has provided oral and written testimony in numerous rate proceedings before the TPSC and the Tennessee Regulatory Authority, including the following dockets and/or companies, many of which are available on the TRA website. Docket captions have been summarized.

TRA #07-00224 Docket to Evaluate Chattanooga Gas Company's Gas Purchase and Related Sharing Incentives
Direct Testimony: http://www.state.tn.us/tra/dockets/0700224.htm

TRA #07-00105 Atmos Energy Corporation for Approval of a General Rate

Increase
Testimony Address: http://www.state.tn.us/tra/orders/2007/0700105cg.pdf

TRA # 06-00290 Petition of Tennessee American Water to Change and Increase Rates
Testimony Address: http://www.state.tn.us/tra/orders/2006/0600290by.pdf
Supp.Testimony Address: http://www.state.tn.us/tra/orders/2006/0600290fm.pdf

TRA # 06-00175 Petition of Chattanooga Gas Company to Change and Increase Rates

Testimony Address: http://www.state.tn.us/tra/orders/2006/0600175jn.pdf

TRA # 05-00258 Petition of the Consumer Advocate to Open an Investigation and Require ATMOS to Show Cause that the Company is not over-earning.

Testimony Address: http://www.state.tn.us/tra/orders/2005/0500258cd.pdf

Rebuttal Testimony: http://www.state.tn.us/tra/orders/2005/0500258hs.pdf

TRA# 04-00288 Petition of Tennessee American Water Co. to adjust rates
Testimony Address: http://www.state.tn.us/tra/orders/2004/0400288bk.pdf

TRA # 04-00034 Petition of Chattanooga Gas to Adjust Rates
Testimony Address: http://www.state.tn.us/tra/orders/2004/0400034dm.pdf

TRA# 03-00491 F.C.C. T.R.O. Review
Testimony Address: http://www.state.tn.us/tra/orders/2003/0300491ib.pdf
Rebuttal Address: http://www.state.tn.us/tra/orders/2003/0300491kn.pdf

TRA# 03-00391 Petition of BellSouth Telecommunications for Exemption of Certain Services
Testimony Address: http://www.state.tn.us/tra/orders/2003/0300391bz.pdf

TRA# 03-00313 Petition of Nashville Gas to Adjust Rates
Testimony Address: http://www.state.tn.us/tra/orders/2003/0300313z.pdf

TRA# 03-00118 Petition of Tennessee American Water to Adjust Rates

Testimony Address: http://www.state.tn.us/tra/orders/2003/0300118bm.pdf
Rebuttal Address: http://www.state.tn.us/tra/orders/2003/0300118ca.pdf

TRA# 01-00704 Audit of Atmos/U.C.G. IPA
Testimony Address: http://www.state.tn.us/tra/orders/2001/0100704cp.pdf

TRA# 98-00559 BellSouth, C.S.A. Docket
(Testimony is currently unavailable)

TRA# 97-01364 United Cites Gas / Establishment of PBR
(Testimony is currently unavailable)

TRA# 97-01262 Permanent Prices
(Testimony is currently unavailable)

TRA# 97-00982 Petition of Chattanooga Gas to Revise Tariff
Hard Copy Attached

Doc#79072

Resume and Publications

A. Dr. Steve Brown - Education, Employment and Testimony

B. Direct Testimony of Steve Brown in TRA Docket No. 97-00982

Publications by Dr. Brown

1. Science and Technology: So Long, Calvin Coolidge, Meter Reading Approaches the 1990s Promising a Pivotal market for Communications Infrastructure

2. AMRA Opinion: No Second Time Around for AMR

3. AMRA Opinion: DOE Proposal Trivializes AMR

4. Economic Incentives for Nuclear Plan Performance: A State Perspective

5. Electric Potential: Bubble Memory Technology: Its Impact on Metering and Rate Structure

6. The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Steve Brown, Economist

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TRA# 03-00391 Petition of BellSouth Telecommunications for Exemption of Certain Services
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TRA# 98-00559 BellSouth, C.S.A. Docket
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(Testimony is currently unavailable)

TRA# 97-01262 Permanent Prices
(Testimony is currently unavailable)

TRA# 97-00982 Petition of Chattanooga Gas to Revise Tariff
Hard Copy Attached

Doc#79072

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE:

PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF

DOCKET NO. 97-00982

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DIRECT TESTIMONY
OF
STEVE BROWN

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INTRODUCTION

Q. Please state your name.

A. Stephen N. Brown.

Q. Where do you work and what is your job title?

A. I am a Senior Economist in the Consumer Advocate Division, Office of the Attorney General.

Q. What are your responsibilities as Senior Economist?

A. I review companies' petitions for rate changes and follow the economic conditions that affect the companies.

Q. What experience do you have regarding utilities?

A. From 1986 to 1995 I was employed by the Iowa Utilities Board as Chief of the Bureau of Energy Efficiency, Auditing and Research, and Utility Specialist and State Liaison Officer to the U.S. Nuclear Regulatory Commission. From 1984 to 1986 I worked for Houston Lighting & Power as Supervisor of Rate Design. From 1982 to 1984 I worked for Arizona Electric Power Cooperative as a Rate Analyst. From 1979 to 1982 I worked for Tri-State Generation and Transmission Association as Power Requirements Supervisor and Rate Specialist. From 1979 through 1995 my work spanned many issues including cost of service studies, rate design issues, telecommunications issues and matters related to the disposal of nuclear waste.

Q. What is your educational background?

A. I have an M.S. in Regulatory Economics from the University of Wyoming, an M.A. and Ph.D. in International Relations with a specialty in International Economics from the University of Denver, and a B.A. from Colorado State University.

Q. Dr. Brown, have you authored any articles relating to your profession?

A. Yes, my articles have appeared in Public Utilities Fortnightly and the Electricity Journal.

Q. Are you and have you been a member of any professional organizations, Dr. Brown?

A. Yes, I am a past member of the NARUC Staff Committee on Management Analysis, a past trustee of and a member of the Board for the Automatic Meter Reading Association, and a current member of the National Association of Business Economists.

Q. Have you studied mathematics and statistics as part of your education?

A. Yes.

Q. Dr. Brown, do you use mathematics and statistics in combination with economics as part of your profession?

A. Yes.

Q. What were you asked to do with respect to this

case?

A. I was asked to form an opinion on the appropriate market-based common equity return, the appropriate overall cost of capital and the appropriate capital structure for Atlanta Gas Light (AGL) Company's wholly owned subsidiary in Tennessee, Chattanooga Gas (CG) Company, as well as to evaluate and assist in the evaluation of the rate of return proposed by other witnesses in this docket.

OPINION ON EQUITY RETURN

Q. In your opinion what rate of equity return is just and reasonable?

A. In my opinion an equity return of 10.55% is just and reasonable.

Q. Dr. Brown, what did you do to identify this just and reasonable return?

A. I examined a group of natural gas companies comparable to AGL.

AGL IS THE APPROPRIATE COMPANY FOR COMPARISON

Q. Why did you consider AGL the appropriate company for deriving the equity return?

A. CG's common equity is owned completely by AGL and is not publicly traded or available over the counter. Investors who desire a common equity interest in CG have only one way to obtain that interest--acquire common stock in AGL Resources, whose financial fate is determined by its prime subsidiary, AGL.

These facts alone suggest that AGL is central to the equity analysis. Also, in this docket AGL's management is well-represented. The company's witnesses -- Messrs. Thompson, Hinesley, and Overcast and Lisa Wooten -- are employed by AGL directly and none of them ever worked for CG directly. This is ample evidence that AGL management strongly directs CG's activities thus making AGL rather than CG the focus of equity analysis.

The direct involvement of AGL's management in this docket clearly indicates that CG's operations are completely intermingled with AGL's, to the point that CG is an operating company under AGL's management in much the same way that Savannah Gas is an operating company under AGL. When AGL has a rate case in Georgia, Savannah Gas is not singled out as a stand-alone investment of funds which forms the basis for a rate of return. Likewise, CG is not a stand-alone investment that forms the basis for a rate of return. The company's cost-of-capital witness, Dr. Andrews, concedes this point very early in his testimony at page 4 lines 12-13, where he says "I undertake the analysis of CGC **as if it were** [emphasis added by Dr. Brown] a stand-alone investment of funds." To me, the wording "**as if it were**" means one of two things: either CG **is not in fact** a stand-alone investment or he does not know if it is a stand-alone investment.

Finally, Dr. Andrews, at page 48 lines 6-8 of his direct testimony, suggests the capital structure of AGL Resources be used to compute CG's weighted cost of capital. These aspects of the rate filing make it appropriate to

determine the cost of capital by using AGL and companies that are comparable to AGL.

Q. Does Dr. Andrews base his cost-of-capital analysis on AGL and companies comparable to AGL?

A. No, but his recommended return includes a premium meant to compensate AGL Resources.

Q. What companies form the basis for Dr. Andrews' cost-of-equity analysis?

A. He selects 22 "small" companies that have actively traded stock, that issue bonds and stocks, and which complete and file regular reports with the Securities and Exchange Commission. In contrast to CG, which is a subsidiary of AGL, many of the 22 companies are parent companies themselves with subsidiaries underneath them. Several of the 22 companies also operate in multi-state jurisdictions.

Q. In your opinion do these "small" companies are a rational basis for a cost-of-equity analysis in this docket?

A. No, I do not. On their face the 22 companies markedly differ from CG, and there is no objective basis for adjusting them so that they would somehow be comparable to CG. Because I focus on AGL, my cost-of-equity analysis uses a completely different set of companies than Dr. Andrews' analysis. A cost-of-equity analysis starts with the selection of comparable companies. To the extent the parties in this docket disagree about the starting point of an analysis, the TRA's job of assessing each

analysis becomes more difficult. However, I have other sound and objective reasons for disagreeing with Dr. Andrews' analysis and results, as I will discuss at a later point in my testimony.

COMPARABLE COMPANIES SELECTED BY DR. BROWN

Q. Dr. Brown, what comparable companies did you use in your analysis?

A. I selected a group of companies composed of AGL Resources, Bay State Gas Company, Brooklyn Union Gas Company, Indiana Energy, Laclede Gas, Northwest Natural Gas, Peoples Energy, and Washington Gas Light Company. Like AGL, all of these companies have subsidiaries.

Q. What evidence do you offer to substantiate your assertion that AGL is comparable to the other eight companies?

A. The proof of comparability appears in Schedule 1. The top portion is titled "Market Statistics" and the bottom portion is titled "Financial Behavior." The market statistics show the strong similarity of the companies. For example, as of December 1996 the ratios of the market price to the book value are similar, and so are the equity ratios, dividend yields, the value of the holdings per shareholder and the average number of years the stock is held. However, the market values have a large spread. The smallest value, $343 million, is about only one-fourth of the largest market value.

Q. Dr. Brown, is the difference in market values of the comparables you selected meaningful?

A. No. My examination of the companies shows that they exhibit similar financial behavior, as indicated by the way they responded to the publication *Value Line*'s criticism of the gas distribution industry. That criticism is quoted in Schedule 1. In early 1995 *Value Line* warned investors to be wary of gas companies that paid out more than 80% of their earnings to dividends. Prior to Value Line's warning many payout ratios exceeded 80%. From 1995 to 1996, however, every company lowered its payout ratio to levels below 80%. This deliberate response by all the companies makes it clear that they have comparable financial behavior.

Q. Is your opinion of the equity return different from the equity return recommended by Dr. Andrews?

A. Yes, he recommends a higher, speculative range of 11.5% to 12.5% and prefers 12.25%, a much higher, speculative rate.

Q. Upon what do you base your equity return opinion?

A. I base my opinion on my analysis of AGL's market-based cost of common equity, which is supported by my analysis of comparable companies.

Q. In your opinion what rate of equity return should the Tennessee Regulatory Authority allow in this docket?

A. My opinion is that the Tennessee Regulatory Authority (TRA) adopt the equity return of

10.55%.

TESTS OF RECOMMENDED EQUITY RETURN

Q. Dr. Brown, did you compare your equity return to those of independent sources?

A. Yes. Chart One summarizes the tests I made. I compared my results to the information published by Merrill Lynch regarding the required rates of return for gas distribution companies in general. I also compared my results with the equity returns recently granted by the Illinois Commerce Commission and the Virginia State Corporation Commission to United Cities, a company currently under the TRA's jurisdiction and one that is included in Dr. Andrews' analysis. The Merrill Lynch returns are shown in Schedule 2. Press releases announcing the Illinois and Virginia decisions are attached as Schedules 3 and 4 respectively.

Q. What was your reason for using Merrill Lynch's data?

A. Merrill Lynch's data reflects the marketplace for gas distribution companies, and I have used their data as a basis of comparison in prior rate cases. From January 1995 through May 1997 Merrill Lynch's equity-return estimates have ranged from a high of 11% to a low of about 9%. My recommendation of 10.55% approximates Merrill Lynch's upper limit of recent equity returns for the natural gas distribution industry.

Q. What was your reason for comparing the recent equity awards by two state commissions?

A. My reason for comparison was to consider independent sources. The comparison merely demonstrates that my recommended return is consistent with recent regulatory decisions regarding equity returns in other jurisdictions.

Q. Did you compare the data from Merrill Lynch and from the various states to Dr. Andrews' recommended return to equity?

A. Yes. Dr. Andrews' recommended return substantially exceeds any reasonable return for the industry, and therefore is more than just and reasonable.

Q. Dr. Brown, is the return you are presenting a fair return?

A. Yes. It is a fair return because it compensates the company for ordinary financial risks it is taking to be in the gas distribution business.

Q. What are the sources of ordinary financial risk to the company?

A. The major risk is that the company's expenses would increase faster than its revenues. However, in this case that risk is negligible. The company's rate base, expenses, and sales are based on projected amounts for a 12-month period ending September 1998. These factors are the basis for the prices that come out of this docket. However, the company's prices are likely to be applied almost a full year before the projections are realized.

For there to be any risk, the company's projected expenses would have to be far less than what actually occurs, or the company's projected sales of gas would have to very different from the actual sales. I know of no substantial evidence suggesting that the company's forecasts will create a financial hardship.

Q. Dr. Brown, is your rate of return sufficiently high to allow the company to attract capital and to maintain creditworthiness?

A. Yes. An annual return of 10.55% is certainly high enough to attract capital and to maintain creditworthiness. The rate-of-return principles of capital attraction and maintenance of credit were set in the *Bluefield* decision, and the rate of return I recommend considers these factors.

Also, 10.55% is an understatement of the amount that the company actually has an opportunity to earn because the actual annual return is achieved through monthly compounding, which raise the return by approximately one-half a percent to 11%.

DISCUSSION OF MONTHLY COMPOUNDING

Q. Is the monthly compounding process typical of the financial world?

A. Yes.

Q. Do monthly earnings have to be constant for monthly compounding to operate?

A. No. Schedule 6 shows that compounding occurs with income-losses and with income-gains. The Schedule is based on the actual monthly income and losses of AGL for the fiscal year 1996. The far right-hand column clearly shows that monthly compounding of $1 at an allowed annual return of 10.55% leads to an effective return of 11.0%. With regard to column (6), at the bottom, the total return is shown as 11.02 cents. The total return would equal 10.55 cents only if the monthly return in column (6) is not added into the cumulative balances in columns (5) and (7), i.e., the cumulative balance would have to be $1 throughout the entire year. But this is not how financial processes work - cumulative balances are maintained on a monthly basis and changes to the balances are recorded monthly - not just annually.

Q. Dr. Brown, are you this docket's only cost-of-capital witness who believes that compounding is a typical financial process?

A. No. Dr. Andrews has made several statements indicating his opinion that compounding is a typical financial process:

1. Dr. Andrews, in his direct testimony page 27, line 5 says that "financial processes occur continuously." Therefore, his discounted cash flow (DCF) analysis is predicated on dividends continuously compounding, indicated at page 26 line 18 of his testimony, a situation

where compounding goes on moment-by-moment, a far more rapid rate of compounding than a monthly rate.

2. Dr. Andrews' direct testimony, page 28, lines 15-17, suggests that compounding a return of 9.53% leads to an effective return of 10%, clearly indicating that compounding adds approximately one-half percent to the return. This is the same point that I have made about compounding.

3. Dr. Andrews was cross-examined in Docket 95-02116 and stated that "Financial processes occur smoothly and continuously. They go -- if this makes the point for you -- minute by minute, hour by hour, day by day and they are not interruptible." His statement occurs at page 8, lines 20-23 of the transcript. A copy of the transcript's cover page and page 8 of the transcript are attached to my testimony as Schedule 7, pages 1 and 2 respectively.

4. His statements under cross-examination are consistent with his direct testimony page 28 lines 10-11, where the question is asked if there is "complete equivalency between

the continuous" rate, such as 9.53%, and a so-called "finite" rate, such as 10%. He answers "Yes."

5. His responses in his deposition of September 9 are also consistent with his testimony. For example, at page 58 line 16 of the deposition he was asked how often compounding occurred:

> "Q. Right, and it doesn't even have to be a series of years, it can be series of months, can't it?"

To which Dr. Andrews responded:

> "A. It could be done months, weeks, days."

He was also asked in the deposition, at page 59 line 10, whether he concurred that compounding is typical of financial processes:

> "Q. ...compounding is essentially accepted by all of our financial markets?"

To which he responded:

> "A. Sure."

Q. What does the term "compounding" mean?

A. The term compounding refers to a process that begins with a certain financial resource, generally called the base or the principal, and then the changes in that are added back into the base or the principal to create a new balance. The changes can be either positive or negative, meaning that the principal is either growing or declining.

Two things affect compounding.

The time-frame of compounding -- how quickly is the change added back to the base? It could occur once a decade, once a year, once a month, every day or every second.

The size of the change during the time frame -- does the base change by 1% a month each month or does it change by 2% in some months and 3% in other months?

The financial community puts these concepts together to say things like "your investment is growing at a rate of 10% per year this year, but last year it lost money at annual rate of 3%." Therefore, compounding describes financial gains as well as financial losses and does not have to occur at the same rate from one moment to the next.

Q. Is compounding process related to concept of working capital?

A. No. Working capital encompasses only the funds

needed by the company to meet its current liability, i.e., the company has to have the funds available to meet its demands for cash flows.

Q. Why are you referring to working capital?

A. I raise it now to assure the TRA does not view monthly compounding as akin to working capital, where positive and negative cashflows are balanced by short-term lending and short-term borrowing.

Q. Is monthly compounding an accurate description of how a distribution company accumulates annual return even when the company experiences seasonal variations in sales, revenues and expenses?

A. Yes. The returns in the months when sales are high balance the returns in the months when sale are low. This is true whether the annual return is viewed as a sum of compounded monthly returns or as just the sum of twelve monthly returns that are not compounded. However, monthly compounding reflects the true nature of financial transactions. Revenues flow in every working day and are available for immediate reinvestment. The company's stocks and bonds can be bought and sold every working day of the year. The best indication that the compounding process underlies the company's financial transactions is the company's late fee, which is applied to consumers' monthly bills if they are not paid by the past due date. The late fee truly shows that "time is money." The quicker the company has the money, the quicker it can be invested to achieve additional returns. This is a perfect fit with the monthly compounding

cycle that typifies financial transactions in our economy. If monthly compounding were not how a gas company accumulated its annual return, there would be no economic basis for charging a late fee.

Q. When Dr. Andrews' recommended equity return of 12.25% is compounded monthly, what return is the company being given an opportunity to earn?

A. The company is being given an opportunity to earn about 12.8%

MORE EVIDENCE THAT AGL IS THE APPROPRIATE COMPANY FOR COMPARISON

Q. If Dr. Andrews' recommended return of 12.25% a just and reasonable return?

A. No. His preference for 12.25% is meant to compensate AGL Resources (the parent of AGL) for the premium the company paid when it purchased CG. At page 3, lines 5-8 of his testimony Dr. Andrews states. "The point estimate is slightly off center in an upward direction in recognition of AGL Resources' long-run inability to earn on a rate base that includes the acquisition premium it paid as part of the price for CGC."

Q. What inferences do you make from Dr. Andrews' statement?

A. The statement confirms that this rate case is about AGL's return and that AGL and companies comparable to AGL should form the basis for an equity analysis. Dr. Andrews' statement also contradicts his later statement at page 4 lines

9-10 where he states: "the source of an investment's financing does not dictate its fair rate of return." His recommendation of 12.25% clearly aims at achieving a return for AGL, the owner of CG.

Q. Is Dr. Andrews choice of 12.25% as his preferred return consistent with his statement: "I treat CGC as if it were a stand-alone investment of funds?"

A. No. If CG were a stand-alone investment there would be no reason for Dr. Andrews to consider the acquisition premium as a factor or justification for choosing 12.25%. This justification is Dr. Andrews' tacit recognition that CG is not a stand-alone investment.

Q. How does Dr. Andrews' supposition of CG as a "stand-alone" investment compare with the testimony of other witnesses for AGL?

A. His supposition is contrary to the facts presented by Mr. Thompson, whose direct testimony, pages 11 through 22, describes the various support services that AGL provides to CG. For example, at page 17 line 6 Mr. Thompson lists several functions provided by AGL. At page 16 lines 4-15 Mr. Thompson indicates that AGL's Treasury and Corporate Accounting departments handle many transactions for CG. At lines 7-8 he says, "All checks for Chattanooga Gas Company are written by AGL." At page 13 line 11 he describes the various departments that have been eliminated at CG.

Q. Do you agree with Dr. Andrews' testimony, at page 6 line 8, that CG has "sharply expanded

demands for financing."

A. No. His statement is contradicted by the capital structure information the company supplied in this docket and in its prior rate case. In docket 95-02116, the company submitted a capital structure of $96.846 million. That structure is attached to my testimony as Schedule 8. In the current docket the company submitted a capital structure of $95.843 million, shown in the company's filing as Exhibit 5 Schedule 9. AGL is withdrawing its investment from Tennessee rather than suffering from a sharply expanded demand for financing

Q. What is the implication of the $1 million decline regarding CG as a "stand-alone investment?"

A. If a stand-alone company's capital dropped by $1 million, there would be an accounting trail, but in this instance there is no trail at all for CG. Therefore, the $1 million difference has to be the result of AGL's decisions and way it adds and subtracts funds to its Tennessee operations.

DERIVATION OF DR. BROWN'S EQUITY RETURN: DCF ANALYSIS

Q. Did you perform an analysis to determine what the return to equity should be for AGL's wholly owned subsidiary?

A. Yes. I performed two analyses: one based on the Discounted Cash Flow (DCF) model and another based on the risk premium model.

Q. What is the Discounted Cash Flow model?

A. The DCF model is a standard way that investors evaluate their potential returns. The model defines the cost of common equity as the dividend yield plus the dividend's expected growth rate.

Q. What is the advantage of using the DCF model?

A. It does exactly what every investor does. It pays close attention to the company's dividend per share of common stock and to the company's ability to raise or lower the dividend and the dividend yield.

Q. What is the dividend yield?

A. Dividend yield is measured as the company's annual dividend divided by the price for the company's stock. I've used the average dividend yield of the comparable companies as a proxy for AGL's dividend yield. The calculations are shown in my Schedule 9. In this instance the calculated dividend yield is 5.17%.

Q. What did you use to measure dividend growth?

A. Since AGL's current dividend growth rate is barely above zero, I used the growth rate derived from Value Line's projection of AGL's dividend in the year 2000, which suggests a growth rate of 5.23% in the near future. Thus my estimated DCF equity return is 10.40%, shown in Schedule 9.

Q. Does the DCF Model account for capital gains that may occur when an investor sells stock?

A. No. The DCF model avoids entanglement with either capital gain or capital loss because the model is tied directly to dividend yield and dividend growth. In addition, losses and gains are a matter of the investor timing the stock's purchase and sale. The DCF model neither protects investors from risk nor penalizes them for what happens in the stock market.

DERIVATION OF EQUITY RETURN: RISK PREMIUM ANALYSIS

Q. In addition to your DCF model, did you use another method to determine the market based cost of common equity?

A. Yes. I used the risk premium method which defines the cost of equity as the market's current debt yield plus an estimated risk premium. For example, a current debt yield of 7% plus an estimated market wide risk premium of 3% produces an estimated common equity cost of 10%.

Q. Is a risk premium analysis different from a DCF analysis?

A. Yes, the two analyses are completely different. For example, dividend growth and dividend yield are crucial to the DCF analysis, but they have no role whatsoever in a risk premium analysis.

Q. What is the rationale of risk premium analysis?

A. Investors require extra payments to assume

additional risk. Economists call this extra payment a risk premium. Equity investments are riskier than debt because equity investments occasionally lose money, thus equity investors require a risk premium or a higher return than debt. For example, equity holders are last in line for the distribution of earnings and also last in line for distribution of liquidation proceeds. In both cases the debt holders are paid first. Any funds left are distributed to the equity holders. Therefore, the cost of equity is the debt yield plus a risk premium for the company.

Q. How did you derive your risk premium model?

A. The model is derived as follows:

$$K_e = R_f + (R_m - R_f) * B_e \quad (1)$$

where

K_e is the cost of equity

R_m is the market rate of return

R_f is the risk free rate of return

B_e is the beta for common stock

and

$$K_d = R_f + (R_m - R_f) * B_d \quad (2)$$

where

K_d is the cost of debt

R_m and R_f are defined above

B_d is the beta for debt

Subtract equation (2) from equation (1) and the result is

$$K_e = K_d + (R_m - R_f) * (B_e - B_d)$$

I treat the beta for debt, B_d, as if it were zero. Since B_d is zero, this raises the cost of common equity that can be derived from this model. Since B_d is zero, the final result is

$$K_e = K_d + (R_m - R_f) * (B_e) \qquad (3)$$

Q. What is the procedure for deriving the cost of equity from this risk premium model?

A. The procedure has six steps:

1. Estimate the market's current cost of debt - K_d.

2. Estimate market-wide rate of return for common equity -R_m.

3. Estimate the market-wide risk-free investment - R_f.

4. Take the difference between steps 2 and 3

5. Multiply the difference by a so-called "Beta" - B_e.

6. Add the result of step 5 to the debt cost in step 1. The result is the estimated cost

of equity from the risk premium model

RISK PREMIUM MODEL: CURRENT COST OF DEBT

Q. What do you use as the current cost of debt - K_d?

A. Since AGL's bonds retain an A rating, I use the monthly average of A-rated bonds for May 1996 through April 1997. Those are shown in Schedule 10 and represent the current trend in capital cost for debt issues of A-rated utility bonds.

Q. What is the value of the K_d?

A. The value of K_d is 7.95%.

Q. Are the A-rated bonds long-term bonds?

A. Not necessarily. For example, the source for this information is the Federal Reserve Board which says these bonds have a maturity of 30 years but call-protection for only 5 years, i.e, after 5 years and depending on the issuing company's discretion, the bonds can be repurchased from the investor.

Q. Is it typical for companies to have call provisions in their bonds?

A. Yes.

Q. What is the purpose of a call provision?

A. It gives the company control and flexibility regarding the disposition of its funds and transfers the risk of interest rate changes from the company to the investor. For example, if a company issues bonds at 10% and six years later interest rates drop to 7%, the company has the option of "calling" the bond from the investor, who then has to find an alternative use for the funds. Continuing with this example, if the company issues bonds at 7% and six years later interest rates rise to 10%, the company has no need to repurchase the bond from the investor, who has the choice of either holding the bond or taking a loss in principal if it is sold.

Q. Why do you use the A rates as a measure of debt cost instead of AGL's embedded debt cost?

A. Risk premium analysis is based on market wide indicators of current debt cost instead of a company-specific embedded cost. Using a company-specific embedded cost would mean that the company with the highest debt cost would also receive the highest return to equity. Conversely, the company with the lowest debt cost would receive the lowest return to equity. Thus using a company-specific debt cost to establish a risk premium would introduce incentives for companies to raise their debt cost as much as possible. That is unreasonable logic and unreasonable financial management. Fortunately, the markets don't work that way. A company's return to equity is not guaranteed to be a certain amount higher than the company's debt cost.

Q. Why do you use the A bond rates as a measure of debt cost instead of the average debt cost of

the comparable companies?

A. The company average would not necessarily reflect current market rates for bonds rated as A, the current rating for AGL's bonds.

RISK PREMIUM MODEL: MARKET RETURN TO COMMON EQUITY

Q. What do you use to estimate R_m, market-wide rate of return for common equity?

A. I use 10.7%, the compound annual growth rate for large company stocks from the period 1925-through 1996. This figure is taken from Ibbotson Associates 1997 Yearbook- Stocks Bonds, Bills and Inflation (SBBI-1997) page 118.

Q. Why are using large company stocks?

A. The comparable companies that I use in my analysis fit into the large company category, defined in SBBI-1997 page 136 as any company exceeding $197.4 million in market value as of September 1996. The smallest market value for my comparable companies is $343 million.

Q. Why are you using historical data to estimate the risk premium?

A. Historical data provides a way to smooth out the wild fluctuations in the risk premium, which is the difference between the risk-free return and market return to common equity. Since return to debt is fairly stable, the

fluctuations are caused by the wide swings in the return to equity. For example, if the return to common equity is large in one year, so is the premium, if the return is small the next year, the premium will be negative.

Q. Why are you using the years from 1925 through 1996 to measure the risk premium?

A. Ibbotson provides historical information on the risk premium from 1925 through 1996, and these years represent the entire term for which information is available. Using the entire data avoids any element of subjectivity that may influence the selection of only a portion of the data. Neither Ibbotson nor anyone else I know of recommends using just a portion of the data. SBBI-1997 discusses this issue at pages 152-153: "A proper estimate of the expected risk premium requires a long data series, long enough to give a reliable average without being unduly influenced by very good and very good and very poor short term returns ... More generally, the 71 year period starting with 1926 is representative of what can happen. SBBI-97 also warns: "Some analysts calculate the expected equity risk premium over a shorter, more recent time period...this view is suspect."

Q. Why are you using 10.7% as the estimate of the market-wide rate of return to common equity?

A. I use that figure because it represents normal performance in the market. I have two reasons for saying so.

The first reason is a plain and simple one: 10.7% is the actual compound rate of growth in

the value of large companies' common stocks. SBBI-1997, at page 49 states: "One dollar invested in large company stocks at year end 1925, with dividends reinvested, grew to $1370.95 by year end 1996; this represents a compound annual growth rate of 10.7 percent." The year-by-year change in the large companies' value is shown in Schedule 11 column (2).

The second reason is also simple. Not all large companies' stocks have advanced at a compound rate 10.7%. Some companies have earned more than 10.7% and others have earned less. In the 71 year period covered by data, there are literally millions of possible outcomes. But out of the millions of possibilities, the number of possibilities below 10.7% are exactly equal to the number of possibilities above 10.7%. Thus 10.7% is the exact middle of all the possibilities that could have occurred. This idea may be expressed another way: there is a 50% chance that the compound return will be 10.7% and a 50% chance that a $1 investment in 1925 would be worth $1370.95 in 1996. Returns higher than 10.7% have a smaller chance of being achieved.

Schedule 12 and Charts 2 and 3 show the exact odds of achieving 10.7% versus the other possibilities.

Q. How did you derive Schedule 12?

A. I have provided the mathematical details in Appendix A. But the heart of the concept is simple. A $1 investment today has two possible outcomes next year -- a gain or a loss. But in the year after next, there are four

possibilities because each possibility in the first year has two possibilities in the second year. The number of possibilities doubles each year. Thus an investment that begins with $1 has 8 possible values three years later, 16 possible values four years later and so forth. The SBBI-97 data on large companies covers seventy one years and literally millions of possibilities. But the odds of each possibility can be easily calculated. I have done that in Schedule 12.

Q. Why have you highlighted certain portions of Schedule 12 and Charts 2 and 3?

A. I highlighted those portions to show the tie-ins of the schedule and the charts back to Schedule 11 and to emphasize the difference between the actual rate of 10.7%, which appears at the bottom of column (2) in Schedule 11 and the figure of 12.7%, which appears at the bottom of column (3), the so-called average of the returns, which I describe as a "biased average."

Q. Why do you consider the average to be biased?

A. The average is biased in the sense that it overstates market returns and leads unwary investors into the mistaken notion that an "average" return has a 50% chance of being achieved, when it does not. The growth rate of 12.7% means that a $1 investment in 1925 is now worth $4768 instead of $1371. Thus the rate of 12.7% is biased.

The bias is created in a very simple way: No one can ever lose more than 100% of their investment, i.e., 100% is the mathematical limit for losses. **However, there is no mathematical limit for an investment's gain.** Therefore, when percentage gains are combined with percentage losses the resulting average is mathematically biased to overstate the true gain in value. An excellent example is provided by Roger Ibbotson, the principal of Ibbotson Associates and the author of SBBI-97. In the July-August 1979 issue of *Financial Analysts Journal*, at page 44, he wrote::

> "Suppose that $1.00 were invested in a common stock portfolio that experienced 100 percent price appreciation in the first year and 50 percent depreciation in the succeeding year. At the end of the first year the portfolio would be worth $2.00; at the end of the second year the portfolio would be $1.00. The [average]...return on the portfolio would be 25 percent ..."

By adding a gain of +100% to a loss of -50%, the net is +50% and the average is 25%. Since the portfolio's value is again $1.00, the actual return is obviously zero, not 25%. Thus, the "average return" is clearly a biased and misleading estimate of the return to equity. This example also shows that the actual return is computed by comparing numbers that represent actual values rather than by averaging numbers expressed as rates of return.

Q. Is there any situation in which the average return is not biased?

A. Yes. If the market always gains, then the average is not biased. In this situation the average return and the actual return are identical. A divergence between the actual return and the average return indicates that losses have occurred. The greater the divergence, the greater the losses in the market.

Q. Is 10.7% derived by comparing two actual values?

A. Yes, it is derived by comparing the market value of large companies' common stock in 1925 with the their value in 1996, which I show in Schedule 11.

Q. Is 12.7%, the biased average in your terms, derived by averaging numbers expressed as rates of return?

A. Yes, it is derived by averaging all the rates of return from 1925 through 1996.

Q. Does the figure 12.7% result from the mathematical bias you described?

A. Yes because there have been several years where the market lost value. This is indicated in Schedule 11 column (2) when the value for an earlier year is greater than the value of a later year. For example, the market index fell from 534.46 in 1989 to 517.5 in 1990.

Q. What are the odds of a company achieving at least a 12.7% return?

A. The odds are less than 1 in 5 or less than 20%, indicating the return represents superior performance rather than normal performance.

Q. What are the odds of a company achieving at least a 10.7% return?

A. The odds are 1 in 2 or 50%, indicating that the return represents normal performance.

Q. Why have you made the effort to explain the differences underlying 10.7% and 12.7%?

A. Market returns vary widely over time, and when people are confronted with extremes the first step in clarifying the situation is to take an average. But with regard to a rate of return, it is a mistake to assume that an average is the mid-point between the extremes and that the average represents a typical value. I want to make this fact clear. In addition, I have not seen any direct testimony presented to the TRA or its predecessor agency where the differences are explained in terms of probability. Without a probability analysis the difference between 10.7% and 12.7% may seem tiny and unimportant. However, when the probability of achieving 12.7% is considered, it is clear that 12.7% is a return representing superior performance in the market rather than normal performance. Thus 12.7% is not a rational basis to set a risk premium rate.

Q. Is it reasonable to describe the risk premium in terms of a probability analysis?

A. Yes. SBBI-97 at page 155 states: "in the investment markets...returns are described by a probability distribution..."

Q. Is the return of 10.7% certain to be achieved?

A. No, there is a 50% chance that it will not be achieved.

Q. Is there disagreement about whether a risk premium should be derived from 10.7% or 12.7%?

A. Yes. The disagreement is generally discussed in terms of a debate about the merits of using the "geometric mean" of market returns versus using the "arithmetic mean" of market returns. The 10.7% figure is the geometric mean of large companies' historical returns, and 12.7% is the arithmetic mean.

Q. Are you using the geometric mean or the arithmetic mean in your risk premium analysis?

A. I use the geometric mean, but I prefer the phrase "actual return." I prefer to call the arithmetic return the "average return."

Q. Do you have support for your choice of the geometric mean over the arithmetic mean?

A. Yes. In addition to the all the reasons I have already described for using the geometric mean, it is also preferred by scholars in statistics and finance as well as professional investment firms. In 1990, Thomas Copeland, et. al. published *Valuation: Measuring and Managing the Value of Companies*. At page 193 they state: "Our opinion is that the best forecast of the risk premium is its long run geometric average." Irving Fisher, considered to be one of the world's greatest statisticians, wrote a book called *The Making of Index Numbers.* In the

1967 edition of the book at pages 29 and 30 Fisher says, "The simple arithmetic average produces one of the very worst index numbers. And if this book has no other effect than to lead to the total abandonment of the simple arithmetic type of index number, it will have served a useful purpose." In 1981 Richard Stevenson and Edward Jennings published, *Fundamentals of Investment 2sd ed.*. At page 272 they say, "Why not simply average the rates of return? Indeed, in certain instances, such a procedure would be satisfactory. However, such an average would generally be meaningless." On March 13, 1990 at page C1 the Wall Street Journal ran the following story, "When Figuring the Rate of Return Don't Be Confused By The Sales Hype." The story compares the average return with the so-called compound return, another common name for the geometric return. The WSJ story says the compound return is "more widely used by investment firms."

There is plenty of support for using the actual market return (the geometric mean) in the risk premium model.

Q. What portions of the risk premium model have you identified thus far?

A. I have identified the debt and equity portions. In terms of the model -- $K_e = K_d + (R_m - R_f) * (B_e)$ --I thus far identified K_d as 7.95% and R_m as 10.7%. I still have to identify R_f, the risk free return and B_e, the beta.

RISK PREMIUM MODEL: RISKFREE RATE

Q. What represents the market-wide risk-free investment, R_f?

A. In this case I am using the three-month U.S. Treasury bills. I will show that the three-month rate is based on a long term perspective of the riskless rate and that it is a better concept to use in this case than a long-term bond.

Q. What is the market-wide risk free rate of return, R_f, based on three-month bills?

A. The risk free rate is 3.7%, which is the compound annual growth rate in the value of the three-month treasury bills from 1926 to 1996. Schedule 13 shows the 71 year history for returns to Treasury bills, and in the entire time there is no loss. The compound rate of 3.7% is the center of all possible outcomes from a $1 investment in three-month bills in 1925. The average rate is 3.8%. It is slightly higher than the actual rate because there were no gains in several years. The three-month rate is the best measure of a riskless rate.

Q. Why is the three-month treasury bill the best measure of a riskless rate?

A. There are three reasons:

1. The three-month bill is a debt instrument. This fits with the risk premium's basic premise: the return to debt is less than the equity return and equity return is determined by referencing debt.

2. Of all the other debt instruments

measures that could be used -- long-term corporate bonds, long-term government bonds, the income portion of long-term government bonds and intermediate term government bonds -- the three-month bill provides the lowest rate. This is consistent with the financial concept that a risk free rate should be lower than rates that reflect risk.

3. A three-month bill is free from losses but the other debt instruments are not, i.e., they are riskier forms of investment than the three-month bill, which is why their rates are higher. Schedule 14 shows the actual return and the average return 1925 to 1996 for each of the debt instruments. For each kind of debt, the difference between columns (2) and (3) indicates the degree to which the losses occur in that particular debt market. Of all the debt instruments, the three-month bill is the safest. Investors are absolutely certain of what cash flows will be received and when they will be received. Unlike the other debt instruments, the three-month bill carries no risk of default or loss of principal.

Q. Is there a contradiction between using the three-month bill as the risk free rate while you are using the cost of A rated bonds in your model?

A. No. I have already said those bonds are not necessarily long-term notes. They have call

provisions that transfer the risk of interest rate changes from the company to the investor. The three-month bill allows the investor to do the same thing the company does: avoid the risk of interest-rate changes.

Q. Is there a way to avoid the risk of losing principal and still use long term bonds?

A. No. SBBI-97 at page 151 suggests that long-term bonds have so-called "income returns." This return is the income an investor would receive if the bond were purchased and held to maturity rather than selling it. SBBI-97 considers the income return to be the "riskless portion" of an investment in long term bonds. I disagree with this concept because it is irrational.

Q. Why is the concept irrational?

A. It is irrational because it assumes an investor can divide a long term bond into a riskless portion and a risky portion. This separation is not credible because a bond is not severable into distinct portions. The purchase of a long term bond always carries the risk that changes in interest rates will cause a change in the bond's value. The concept of "income returns" also suggests that once a long term bond is purchased, the investor will take no action until the bond matures and do nothing in the face of interest rate changes. This behavior is just the opposite of the behavior assumed in a call provision, which gives the issuer the flexibility to act when interest rates change. It is irrational to assume that the issuer of a bond is free to respond to interest rate changes but that the bond's buyer is not.

Q. What portions of the risk premium model have you identified thus far?

A. In terms of the model -- $K_e = K_d + (R_m-R_f)*(B_e)$ -- I have identified K_d as 7.95%, R_m as 10.7% and R_f as 3.7%. The term (R_m-R_f) is equal to 7%. This amount would be smaller, as would my recommended rate of return, if I were to use any debt instrument other than the three-month bill. For example, if I were to use long-term government bonds, the term (R_m-R_f) would be (10.7%-5.1%), which equals 5.6%. This lowers the risk premium equity return by 1.4%, which is the difference between 7% and 5.6%. I still have to identify B_e, the beta.

RISK PREMIUM MODEL: THE BETA

Q. What does beta measure?

A. Beta measures how an individual company's market value changes relative to the change in the value of the entire market. For example, if a company's market value increases from $10 to $11, then the company's value increases by 10%. If the entire market's value increased from $1000 to $1200, then the entire market's value increases by 20%. The beta is calculated as .5, which is the ratio of 10% divided by 20%.

The market itself has a beta of 1. If the company's beta is one, then the company risk premium is the same as the market-wide risk premium. Thus if a company's beta is less than 1, then the company is judged less risky than the market. Beta is also used to compare the relative riskiness. For example, a beta of 0.4

is less risky than a beta of 0.6.

Q. Did you calculate betas for AGL and the comparable companies?

A. Yes, and I also calculated the betas' accuracy. The betas and their tests of statistical accuracy, the T-statistic, appear in Schedule 15, pages 1 and 2 respectively. The average beta shown at the bottom of page 1 Schedule 15 is transferred to Schedule 16, which provides results of the risk premium analysis.

Q. What is the beta's value in your model?

A. The value is .458 and is shown in Schedule 16 at the bottom of column (b).

Q. What is the estimated equity rate of return that is derived from your risk premium model?

A. The model gives a value of 11.14%. In terms of the model -- $K_e = K_d + (R_m - R_f) * (B_e)$ -- the equity return is 11.14% = 7.95 + (10.7%-3.7%)*.458.

Q. Do you use all the betas in Schedule 15 to develop the figure of .458?

A. Yes. I used the average betas that have an average T-statistic greater than 1.

Q. Why did you use the T-statistic and T-statistic greater than 1?

A. In general, the T-statistic indicates how well a summary number represents the group from which the summary number comes. In this case

the summary number is a beta, which few people are familiar with. But the T-statistic can also be explained in terms of an average, a summary number which everyone uses almost everyday.

For example, I may know that a certain group of people are, on average, 40 years old. But the average is just a short-hand description of the group. The average alone does not indicate anything about the group's composition. The group could be composed of children younger than 10 and elderly people over 70. The group as a whole just happens to have an average age of 40 even though 40 is not at all representative of anyone in the group. In this case the T-statistic is likely be low, about 1 or less. On the other hand the group could be composed of people between 36 and 42, who as a group, just happen to have an average age of 40, but in this case 40 is fairly representative of anyone in the group. In this case the T-statistic is likely to be high, about 2 or more. The higher the T-statistic, the more likely it is that a group's summary number or average is a good representation of the parts that make up the group. Statisticians express the same idea by saying "the beta is statistically different from zero."

Q. What is the economic significance of the betas' values you found?

A. All the values are far less than 1, which means that AGL and the comparable companies are far less risky investments than the market as a whole. In addition, the values do not vary much for any particular company, which means that investors **do not** perceive any substantial change in risk for these companies.

Q. How did you derive the betas?

A. I used the monthly percentage change in the S&P 500 index to represent the market-wide return and the monthly percentage change in the company's stock price to represent the company's return. The change is calculated as: Price at the end of the month divided by price at the beginning of the month -- the result is converted to a natural logarithm and then the beta is calculated.

Q. **Did you compare your betas to those estimated by anyone else?**

A. Yes. My betas are larger than those estimated by Dr. Andrews for his companies, shown at Schedule 9 of his direct testimony. The average for his betas is .27. This figure includes 5 negative betas. When Dr. Andrews implements his model he excludes the negative betas and raises his average to .41, which is still lower than the average of my betas, .458.

Q. Is the value of .458 a reasonable value?

A. Yes.

THE APPROPRIATE RETURN OF 10.55% COMPENSATES FOR MONTHLY COMPOUNDING

Q. What is the range of annual equity returns that you have established?

A. I have established a range of 10.4% to 11.14%.

Q. In your opinion, within the range of 10.4% to

11.14% what value is appropriate?

A. In my opinion the appropriate annual value is 10.55% because this compensates for monthly compounding that creates annual returns. Even though the range's mid point is about 10.8%, this can be converted into a return of 11.3%, an amount well-beyond my upper limit of 11.14%.

Q. Are there other experts who believe that annual returns are achieved by compounding monthly returns?

A. Yes. This financial principle pervades the data in SBBI-97, Ibbotson's 1997 Yearbook. For example, my Schedule 12, column (3) for the year 1996 shows a value of .2307 or 23.07%. My Schedule 17 shows exactly how .2307 is derived. This process is exactly the same as the one shown in my Schedule 6. Monthly compounding is the basis for all the annual returns shown in Dr. Andrew's Schedule 10 and my Schedule 11. But this is normal because SBBI-97 at page 49 explicitly says: "Annual total returns...for each asset class are formed by compounding the monthly returns." Thus in my Schedule 12, column (2) for the year 1996, the amount of 1370.95 equals 1.2307*1113.92, or stated in words:

Annual Return This Year Equals:
12 Most Recent Monthly Returns Multiplied Together, Which Are Then Multiplied by Annual Return Last Year.

Returning to Schedule 17, it is important to notice that .2307 is larger than the sum of the monthly returns in column (2). If those returns were added together they would sum to only

.2148. This is further proof that annual returns are actually achieved by multiplying monthly returns together, i.e., monthly compounding. This also substantiates the findings in my Schedule 6, where an allowed annual return of 10.55% is subdivided into monthly returns that actually yield 11.0% over a 12 month period.

Q. Isn't it true that monthly compounding introduces an upward bias to a prospective annual rate of return?

A. Yes, and here is how the bias occurs. Lets say that TRA surveillance form 3.03 line 27 for a month shows an annual return of 11% for a certain company. If there is agreement that annual returns are formed by monthly compounding, then we know that the sum of the monthly returns is 10.55%, but when the returns are multiplied together the annual return is 11%. Now suppose that the company files a rate case and asks for an 11.5% return. If the proposed rate of return were subdivided on a monthly basis, the sum of the proposed monthly returns should be 11% to ensure that when they are compounded monthly, the result does not exceed 11.5%. If the monthly returns sum to 11.5%, then in effect, the allowed rate of return is 12%.

Another way to understand the compounding effect is to consider how the test year rate base is calculated. The rate base is actually an average of the rate base at the beginning of the test year and the rate base at the end of the test year. Thus the value of rate base already includes 6 months of reinvested earnings. Therefore, when a rate of return is

applied to the rate base, the company is actually earning on its earnings. This is another way to achieve monthly compounding. If this aspect were implemented in terms of Schedule 6, the beginning balance would not be $1 but about $1.06.

Q. Is there any document in this docket where a proposed annual return is subdivided on a monthly basis?

A. The only one I know of is my Schedule 6.

Q. What equity return do you recommend in this case?

A. I recommend a rate of 10.55%, an amount between my DCF rate of 10.4% and 11.14%, the risk premium rate. I choose 10.55% because I know that monthly compounding gives the company the opportunity to earn a higher return. I also choose 10.55% because I know that the rate base already includes 6 months of reinvested earnings before the rate of return is applied to the rate base, thus giving the company another opportunity to earn a higher return

Q. What compounded return can the company earn with an annual rate of 10.55%?

A. The monthly compounding process gives the company an opportunity to earn approximately 11.0%.

CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

Q. What are your findings regarding capital structure?

A. The capital structure in this case appears in the company's filing as Exhibit 5, Schedule 9. Since the amounts in that schedule are derived from AGL's capital structure, CA data request 42 asked the company to provide support for the calculations. The company's response is attached to my testimony as Schedule 18. None of the projected balances in that document are explained or supported by the company. For example, the preferred stock balance in 1997 is $58.4 but the projected balance in 1998 is $70 million. Despite this hefty increase, no explanation is provided. Continuing with this example, AGL's long term debt is shown as $659.5 million in 1997 and 1998. However, the company's response to CA data request 24 showed a balance of $584.5 million as of April 1997. This is an unexplained difference of $75 million. In addition, the new debt's interest rate is not provided. Also, according to the company's response to CA data request 23, all long term debt and preferred stock is held by AGL instead of its parent holding company, AGL Resources. Therefore, the $75 million cannot be attributed to debt issues by the holding company. Finally, AGL's response to data request 42 does not show how the amount of the CG capital structure, $95.8 million, is derived. Instead, the response shows how $95.8 is allocated to the different aspects of the capital structure.

In sum, the amounts shown in Schedule 18 are different than what I expected, but I do not believe the differences are material to my analysis, which relies on the portions and the estimated costs. However, my recommended overall return is neither an endorsement nor an

acceptance of the rate base that will be applied to the overall return. To the extent that the projections in Schedule 18 are not supported, the company's filed rate base is questionable.

Q. What weighted overall capital cost do you recommend?

A. In my opinion a cost of 8.85% before compounding, shown in Schedule 19.

Q. What compounded overall return can the company earn with an annual rate of 8.85%.

A. The company has an opportunity to earn about 9.3%.

ANALYSIS OF METHODS EMPLOYED BY THE COMPANY'S COST OF CAPITAL WITNESS

Q. You have stated that you disagree with Dr. Andrews' analysis, can you explain your reasons?

A. Yes. At page 4 lines 22-23 of his direct testimony he states: "I measure the costs of equity capital of ...small publicly held gas distributing companies and impute their cost of equity to CGC." I have already pointed out an obvious difference between these companies and CG -- they are independent financial entities who have actively traded stock while CG has no actively traded stock because it is a wholly owned subsidiary of AGL. This alone suggests that his analysis is inappropriate. However, after scrutinizing his testimony and his data

sources, I conclude that his equity returns -- 14.39%, 14.38%, 14.23% , 12.5%, 12.17% and 11.06% shown at page 47 of his testimony -- are based on an irrational analysis.

SMALL COMPANY APPROACH IS IRRATIONAL

Q. Why is the analysis irrational?

A. The small company data base that he uses does not represent the performance of small companies. Instead, the data base represents the performance of one particular mutual fund out of more than 200 funds that specialize in buying and selling small company stocks. The particular mutual fund used by SBBI-97, the very same one that Dr. Andrews uses, is named the *Dimensional Fund Advisors 9-10 Small Company Mutual Fund* (DFA 9-10 fund). SBBI-97 at page 51 says; "...the small company stock returns series is the total return achieved by the Dimensional Fund Advisors (DFA) Small Company 9-10 Fund."

However, the fund requires an initial purchase of $2 million dollars. This is well beyond the means of stockholders who own the companies used by Dr. Andrews. The fund also has a highly unusual ownership concentration, one that is certainly not representative of a gas distribution utility. In 1996 the fund had assets of $1.18 billion with over $625 million held by five owners that are actually pension funds:

OWNER	OWNERSHIP PERCENTAGE

Charles Schwab & Company Inc.	31.44%
State Farm Insurance	10.76%
Pepsico Inc. Master Trust	8.87%
Owens-Illinois	5.48%
National Electrical Benefit Fund	5.26%

This ownership pattern and the $2 million minimum investment clearly indicates that the so-called "returns to small companies" are actually returns to well-financed pension groups rather than being a return that is accessible to ordinary investors. There would be no incentive for anyone to make a $2 million minimum investment and buy into the DFA 9-10 fund if such returns were accessible to ordinary investors. Also, these returns are derived from the capital gains made by the constant buying and selling of stock, a far different process than the way in which a gas distribution company makes money.

However, even the returns themselves are open to question because the methods used to calculate the fund's return are not equivalent to the *return-on-assets concept used in utility regulation*. *In 1996 the fund's return on assets was 8.75%*. Dr. Andrews' Schedule 6, page 1, the far-left column titled "Small Company Stocks" shows the return as 17.62%. He uses this amount and the remaining figures in that column to develop the return differentials of 9.16%, 7.57% and 6.86% shown on the right side of the schedule. Those amounts are repeated in Schedule 6 page 2 and in his direct testimony, at the bottom of page 45 under the column titled "Equity Diff" and lead to a huge cost of equity, 14.3%.

These figures are not credible, not only for the

reasons I have just discussed, but also for *the overlapping directorates of the DFA 9-10 fund and SBBI-97*. Mr. Robert G. Ibbotson is the Chairman and President of Ibbotson Associates, and the publisher and author of SBBI-97. He is also on the Board of Directors of the DFA 9-10 fund. This strongly implies that the small company data used in SBBI-97 is not derived from an independent source and that the data may overstate the actual returns. This possibility is already substantiated by the difference between 8.75%, the return on assets, and the so called return of 17.62% used by Dr. Andrews. Mr. Ibbotson's dual role is indicated in the Statement of Additional Information published March 28, 1997, as a supplement to a prospectus issued the same date by DFA Investment Dimensions Group, Inc.

These factors demonstrate the extraordinary weakness in the small company analogy that Dr. Andrews uses to estimate the cost of equity. But there is another contradiction in the data: in 1994 only 9 of Dr. Andrew's companies were owned by the fund, in 1995 and 1996 only 11 of the companies were owned by the fund. Thus half of Dr. Andrews' companies are not considered "small" by the fund itself.

Taken as whole these factors make it plain that the small company analogy is an irrational approach to setting the equity return in this docket. In my opinion the TRA should disregard the results of Dr. Andrews' small company analysis, shown in his direct testimony at the bottom of page 45.

Q. What are sources of data that support the assertions you have made?

A. My data is taken from four different sources:

1. DFA Investment Dimensions Group Annual Reports for the Years Ended November 30, 1996 and November 30, 1994 and DFA's SEC10K filing for 1995.

2. Statement of Additional Information, Supplement to DFA's Investment Dimensions Group, Inc. Prospectus of March 28, 1997.

3. Morningstar, Inc.'s Reports on Mutual Funds, as of May 31, 1997.

4. SEC Form 10Ks and 10Ka-1 for Dr. Andrews' companies and the DFA Group.

Q. What is Morningstar Inc.?

A. Morningstar is a software and data base firm that maintains records on over 8000 mutual funds and tracks their performance. The company is located in Chicago.

Q. What schedules have you set up from this data?

A. Schedule 20 is a summary of Morningstar's reports on 230 mutual funds that specialize in buying and selling small company stocks. About 30 concentrate on foreign stocks and the remainder focus on domestic stocks. The funds are arranged in descending order according to the amount of the initial minimum investment. The funds managed by the DFA group are among the most expensive funds to purchase. Nearly all of DFA's funds require $2 million minimum investment. For all 230 funds taken as a group, there is a systematic difference between the

rate of return on assets and the 1996 return as reported by the funds. The return on assets is much lower than the other so-called return.

This discrepancy was so large that I was compelled to cross-check the accuracy of the Morningstar report on the DFA 9-10 fund against the data in the DFA 1996 annual report. The Morningstar report is Schedule 21 and the DFA report on the fund is Schedule 22. Although the data is not identical they are close enough to be substantially the same. For example, Morningstar reports assets of $1107 billion and the DFA annual report shows assets of $1181 billion. In Schedule 21 I have highlighted the portfolio statistics showing an exact match between Morningstar's data and DFA's. This suggests that Morningstar's calculation of a return on assets is credible even though the DFA report does not provide this measure. Also, the DFA report, the line titled "Net Gain (Losses) on Securities (Realized and Unrealized)" represents capital gains and losses by the fund. Clearly, the fund is completely dependent on capital gains to make a return, unlike a gas distribution company that sells a product and a service. This, too, makes the fund an unreasonable basis to develop returns for a gas distribution company.

Schedule 23 shows DFA's Statement of Additional Information, the cover page and pages 20-22. The fund's method of calculating a return is shown from Schedule 23 page 3, at the bottom, to the schedule's page 4 at the top. The description is vague and not articulated through any readily understood example. This sharply contrasts with the way all parties calculate the return on assets that a gas

distribution utility receives. Therefore, returns to mutual funds, such as the amounts in Dr. Andrews' Schedule 6, page 1, the far-left column titled "Small Company Stocks," cannot be used to estimate the *return-on-assets* that is granted to a gas distribution company.

Schedule 24 shows DFA's Statement of Additional Information, pages 10, 11 and 15, which respectively list the company directors and the major owners of the fund. Mr. Ibbotson's name appears at the second page, the third listing from the top. This confirms that the DFA 9-10 fund and SBBI-97 have overlapping directorates. Page 15 confirms the ownership pattern of the fund.

Q. How do you know that investors in Dr. Andrews' 22 small companies would be unable to buy into the DFA fund?

A. My opinion is based on the data I gathered about Dr. Andrews' companies. Schedule 25 column (6) shows the average value of the holdings per shareholder for Dr. Andrews' companies. The maximum value is $53,171 and the average value is $28,195. The DFA fund's initial investment is $2 million, about 50 to 100 times larger than the values shown in column (6). It is impossible for stockholders of Dr. Andrews' companies to buy into the DFA fund.

Q. How do you know that the DFA fund included only half of Dr. Andrews' small companies?

A. I acquired DFA's annual reports for 1994 and 1996 and the company's SEC 10K filing for 1995. Those reports list the companies in the fund.

Schedule 26 shows the results.

Q. Is it your opinion that Dr. Andrews actually used the 22 "small publicly held companies" to estimate the equity returns of 14.3%?

A. No, Dr. Andrews did not use those companies. In my opinion he used the concept of "small companies" to make a link with the purported returns of the DFA fund, which is the real source of the huge equity-return estimates that appear in his direct testimony at the bottom of page 45. Also, nine of Dr. Andrews' companies do not fit the definition of a small company that is given by SBBI-97 at page 136: A small company is one with a market value less than $197.4 million as of September 1996. My Schedule 25 shows 9 of Dr. Andrews' companies exceeding that value on April 30, 1997. This strongly suggests that Dr. Andrews' companies are composed of two dissimilar groups that are viewed differently by the market.

RETURNS OF 12.5% AND 12.17% ARE BASED ON LARGE COMPANY DATA, MISUSE OF DATA AND IRREGULAR, UNSUPPORTED PROCEDURES

Q. Are Dr. Andrews' other returns derived from the small company concept and the DFA fund?

A. No. He uses large companies to derive the returns of 12.5% and 12.17%. The returns appear in his testimony at page 44 lines 21-22 and at page 45 lines 1-2 and are derived from his Schedule 10. The schedule's left side has a column titled "Common Stock Total Returns." This name is wrong. In his note at the bottom of the schedule he says data for the years

1987-1995 is drawn from "Exhibit A-1" of Ibbotson's 1996 yearbook. The correct name is "Table A-1 Large Company Stocks: Total Returns." A portion of the table from the 1996 yearbook is attached to my testimony as Schedule 27. Note the title of column (3) in my Schedule 11 and the exact match between the amounts in column (3) from 1988-1996 and the amounts listed in Dr. Andrews' so-called "Common Stock Total Returns."

Contrary to his assertion, "I measure the costs of equity capital of ... small publicly held gas distributing companies," Dr. Andrews uses large companies without acknowledging the fact nor explaining why he has done so. This undermines his entire analysis, making it an irrational basis to determine a return to equity.

Q. Does Dr. Andrews use the data correctly?

A. No. He limits Schedule 10 to a history of 10 years instead of a 71 year history recommended by SBBI-97.

Q. Are you suggesting that every recommendation of SBBI-97 has to be followed?

A. No. Although SBBI-97 is a useful tool and an authoritative source for some aspects of developing a rate of return, its authors are fallible, as I have already demonstrated with regard to the small company issue. However, it is contradictory to invoke an authoritative source to justify one position and then depart from the source's recommendations in other positions without explaining the reasons for the departure.

Dr. Andrews has departed from the standard practice of using a 71 year history to derive the risk premium differential. His direct testimony offers neither a justification nor an explanation of his reasoning. In their absence, his choice of a 10 year history appears arbitrary and calculated to increase the estimated cost of equity.

For example, his Schedule 10, the line titled "Averages" shows that: .1604 - .0778 = .0826. These values appear in his direct testimony at page 44 line 21:

K_e = .0133 + .0778 + (.41)*(.1604-.0778)

K_e = .125 = 12.5%

However, if Dr. Andrews had taken the data for the 71 year period, as the source recommends, the averages would be different than what he shows in Schedule 10.

The figure of 16.04% would decrease to 12.7%, which is the average return to large companies and which is shown in my Schedule 11 at the bottom of column 3. The figure of 7.78% would decline to 5.2%, which is shown in my Schedule 14 in the line titled "Income Portion of Long-Term Government Bonds" and under the column titled "Biased Average." If these new figures were applied to his equation at page 44 line 21, the new result would be:

K_e = .0133 + .052 + (.41)*(.127-.052)

K_e = .0961 = 9.61%

A similar result occurs in the equation at line 1 of page 45 of his direct testimony, where the

new value would be 9.31%.

The use of a 10 year history is vital to Dr. Andrews' results. However, the exact reason he chose this period is not discussed in his testimony. Therefore, I recommend that the TRA disregard the estimates of 12.5% and 12.17% because they are arbitrary and unreasonable.

In fact, his formulation of the risk premium model is irrational.

Q. Why is his risk premium model irrational?

A. Dr. Andrews' model is irrational because it is not tied to the debt markets faced by AGL, the "A" rated bond market, despite his lengthy discussion of AGL's debt quality at page 18 of his testimony. The only place in his analysis where he uses "A" rated corporate debt is in a DCF analysis appearing in his testimony at page 46 lines 16-17, which shows returns of 8.98% and 9.35%. These figures are repeated at page 47 lines 7-8, where he describes these numbers as "DCF Over Various Debt Instruments."

This portion of his testimony contradicts a statement in his deposition of September 9. In that deposition, from page 43 line 24 to page 44 line 3, he states: "One of the lines of analysis that I pursue is the equity over debt cost approach, risk premium approach; and I used some of the costs of the debt that Atlanta Gas had outstanding and found differentials of equity cost over that." However, Dr. Andrews has not used AGL's debt or "A" rated bonds in any risk premium analysis, but only in the DCF analysis he describes at pages 46 and 47 line 7 of his testimony. His highest set of returns --

14.23%, 14.38% and 14.39% derived from his small company analogy, and his second highest set of returns -- 12.5% and 12.17% -- are completely unrelated to the "A" bond market or to AGL's debt.

Q. Is your risk premium model rational?

A. Yes. My risk premium model is based on the general principle that equity returns have to be compared to and exceed corporate debt. In this particular case the debt in question is the "A" bond market. If I expressed the principle instead of the numbers, the model would be:

K_e = Current Cost of A Rated Utility Bonds + $(R_m - R_f) * (B_e)$

Dr. Andrews' model does not begin with corporate debt. Instead, his model begins with the concept of "Long-Term U.S. Govt. Bonds Income Component Returns." If I expressed his idea instead of the numbers, his model would look like:

K_e = 1.33% +Long-Term U.S. Govt. Bonds Income Component Returns $+(R_m - R_f) * (B_e)$

Therefore, Dr. Andrews' model is based on the idea that equity returns have to be compared to and exceed the returns of long term government bonds instead of corporate debt. This is an irrational basis to begin an analysis because returns to government bonds are always lower than returns to corporate bonds. My Schedule 14 clearly shows that corporate bonds outperform government bonds. Therefore, Dr. Andrews' model

has a starting point that is bound to be lower than the starting point in my model. However, he raises the starting point of his model by resorting to a figure of 1.33%. This amount is not related to debt, corporate or government; nor is it related to equity returns of either large or small companies.

Q. What does the 1.33% relate to?

A. The figure is not related to anything because it is a nonsense-number.

Q. How is 1.33% a nonsense-number?

A. Dr. Andrews explains the derivation of 1.33% in his direct testimony, page 44 lines 13-14. The derivation is irrational for two reasons:

1. Dr. Andrews is dealing with numbers that cannot be treated as if they are "per day, per week, per month or per year" numbers. Just as the assertion -- "You are 6 feet tall per month, so in 12 months you will be 6X12=72 feet tall per year" -- is nonsense, so too is Dr. Andrews' number of 1.33%.

   This point becomes clear by examining his derivation of 1.33%. In his Schedule 9 under the "Alpha" column, there is a number, .0011, which is the average of the alphas that have a positive beta. Thus .0011 is the basis for deriving .0133 by the formula at page 44 lines 12-13 of Dr. Andrews' direct testimony:

$$.0133 = (1 + .0011)^{12} - 1$$

Although he does not say that he is deriving his alphas from five years of monthly data, he is. At page 42 lines 6-12 of his testimony Dr. Andrews explains that he derives his betas with five years of monthly data, but every time a statistical regression produces a beta an alpha is created too. This is why his work and mine both have alphas as well as betas.

He treats the value .0011 as if it were a monthly value that can be compounded into an annual figure. This is why he uses 12 in his formula:

$$.0133 = (1 + .0011)^{12} - 1$$

The alphas and betas are derived from the same data and the same months. If the alpha is a monthly rate, isn't the beta a monthly rate, too? If the beta is not a monthly rate, how can the alpha be a monthly rate? If his beta of .41 were compounded monthly the result would be:

$$60.75 = (1 + .41)^{12} - 1$$

If this value were placed into Dr. Andrews' original formula the cost of equity would be:

$$K_e = .0133 + .0778 + (60.75)*(.1604-.0778)$$

$$K_e = 5.10 = 510\%$$

60.75 is produced in exactly the same way as Dr. Andrews' produced .0133. If

60.75 is dismissed as incredible or fictitious, then its counterpart, the "annualized" alpha, is an unreasonable number and .0133 should be rejected, too. Both numbers are unreasonable. It is irrational for Dr. Andrews to treat the alpha as a monthly figure that can be compounded to an annual one. His treatment further suggests that the alpha can be compounded according to the time frame of the data used, i.e., if the alpha and beta are derived from monthly data then the alpha can be compounded monthly, but if the data is weekly, then the alpha can be compounded weekly. This too is irrational.

For example, if I took the weight of 22 people each month for 60 months and then took an average, I can say "based on monthly data the average weight *per person* is 150 pounds" but it would be wrong to say "because I collected my data on a monthly basis each person weighs 150 pounds *per month* and 1800 pounds *per year*." This is the exact logic that Dr. Andrews employs. The difference between this example and Dr. Andrews' irrational procedure is the size of the numbers.

If the beta is .41, as in Dr. Andrews' results, then the value of the company's stock changes 41 cents *per $1 change in the market's value*, whether the market's change is measured over a day, a week, a month or a year -- .41 is not compounded to

a higher figure nor reduced to a lower one. The same logic applies to the alpha.

In my opinion the TRA should disregard Dr. Andrews' figure of 1.33% because it is irrational.

2. Dr. Andrews' direct testimony does not provide any tests of statistical accuracy for the alphas in his Schedule 9. In the absence of this data, my opinion is that the alpha should be presumed to be zero.

Earlier I said that every time a statistical regression produces a beta a so-called "alpha" is created too. Since his overall positive beta is .41 while mine is .458, I expected this similarity to be carried through to the alphas, and it is. The values of his alphas are very close to zero, just as they are in my analysis, at Schedule 15 page 3. However, page 4 of Schedule 15 shows the alphas' statistical measures of accuracy, the T-statistics. They are tiny, meaning the alphas are no different than zero.

The typical pattern of alphas, betas and their statistical accuracy are provided in the table below.

Betas	Alphas
Positive Values	Very Close to Zero- May Be Positive or Negative

High T-Statistics Indicate Accuracy	Low T-Statistics Indicate Inaccuracy

Schedule 15 fits this pattern. Dr. Andrews' data should show the same pattern, at least for his positive betas.

When the alphas are no different than zero, they do not add anything to the cost of equity, and there is no need to use the alphas. In this case the formula looks like:

$$0 = (1 + .0000)^{12} - 1$$

The alpha is zero. This is why alphas are thought of as having no value and no meaningful economic interpretation and why they never appear with betas.

I do not know of any financial publication that provides betas and alphas nor do I know of any model that treats the alphas the way Dr. Andrews does.

Q. Did you ask Dr. Andrews to provide the tests of statistical significance for the alphas and betas that he calculated?

A. Yes. He did not supply them, consequently his conclusions are not supported by material and substantial evidence. His response is attached to my testimony as Schedule 28.

Q. Do you have any comment regarding his response?

A. Yes. Since Dr. Andrews has not provided the tests of statistical significance, I am even more concerned that his alphas are really no different than zero. In my analysis the alphas are zero and they are not statistically significant. Also, it is contradictory for Dr. Andrews to calculate sums and averages for the betas and alphas, as he does in his Schedule 9, and then state in his response: "Tests of significance, such as T-statistics from the regressions related to individual stocks cannot be summed or averaged across the composite." I have done exactly that in my analysis. In fact, its results are appropriate.

Q. Why are your results appropriate?

A. All my betas are positive. They are estimated over twelve contiguous 60 month periods, with the first period ending in May 1996 and the last one ending in April 1997. This procedure captures any change in how the company's beta value is responding to the market. I provide tests of statistical significance, and the tests are reasonable. The alphas are zero, their tests of statistical significance indicate the true values are zero, and they play no role at all in my return. All of these factors taken together reinforce the implications of my Schedule 1, which demonstrates the comparability of my group of companies.

In comparison, Dr. Andrews' analysis has 5 negative betas, which he dismisses as "analytically indefensible" at page 43 line 18 of his direct testimony. Dr. Andrews does not explain why the results are "indefensible," but

it is clear that if he did not exclude the negative values, his estimated return of 12.5% would be lower. Therefore, the negative betas appear to be indefensible because they would lower the company's return. He relies on the alpha to raise his estimated returns and performs an irrational procedure to boost an estimated return by 1.33%. In addition, he does not provide tests of statistical significance, even when asked to do so. Taken together, these factors indicate that Dr. Andrews' companies do not form a comparable group that is a rational basis for estimating a rate of return. These factors further reinforce what my Schedules 25 and 26 already suggest -- his companies are composed of two dissimilar groups that cannot be a rational basis to set a rate of return in this docket.

Q. What is your opinion regarding Dr. Andrews' statistical analysis is shown in Schedule 9 of his testimony?

A. In my opinion the TRA should disregard the conclusory analysis because it is arbitrary, irrational and unsupported by material and substantial evidence. Therefore, his analysis cannot constitute a basis for a decision.

DCF ANALYSIS IS BIASED UPWARDS

Q. What is your opinion of Dr. Andrews' DCF analysis?

A. His DCF recommendation of 11.06% is derived from Schedule 8, page 2, of his testimony. My opinion is that his result is biased upward by approximately 2% because his rate of 11.06% is

based on only 4 companies instead 21. He ignores the results of the 17 other companies that he considers as comparables. Therefore, his recommendation of 11.06% is not representative of the group that he has designated as comparables. On the other hand, if his companies are composed of two groups not comparable to each other, then his decision to ignore some would be rational. However, if this is why he has ignored 17 companies, then this makes all his other analyses irrational, too. For example, of the 17 companies ignored in Schedule 8, 12 of them are used in his Schedule 9 to derive the returns of 12.5% and 12.17%. On its face this is clearly an irrational procedure, and Dr. Andrews offers no explanation. It is my opinion that the TRA should disregard his recommended DCF rate because it is biased and not supported by material and substantial evidence.

RANGE OF 11.5% TO 12.5% IS IRRATIONAL

Q. Do you have any concluding opinions regarding the equity returns suggested by the company's cost-of-capital witness?

A. Yes. In his direct testimony, at page 47 lines 14 and 23, Dr. Andrews concludes his analysis by recommending a range of 11.5% to 12.5%. Dr. Andrews suggests this is a reasonable range because he has found returns that are well above the range. At page 47 lines 18-22 Dr. Andrews says "The Small Stock equity risk premiums...over 14%...cannot be dismissed."

The "small company" premiums can and should be dismissed because:

They are based on 1 mutual fund out of 200;

The fund has a minimum investment requirement of $2 million;

The stockholders of Dr. Andrews' companies cannot afford to buy into such a fund;

The directorates of the Ibbotson Associates and the DFA 9-10 fund overlap - suggesting that the funds' return is not calculated by an independent source;

The fund's return on assets is only 8.75%, an amount provided by Morningstar Inc., a source that is independent of Ibbotson Associates and DFA Investment Dimensions Group - the manger of the DFA 9-10 fund;

The difference between the fund's return on assets and its so-called annual return means that a mutual fund's return cannot and should not be used to grant a utility's return on assets;

The fund relies exclusively on capital gains as the source of its return.

The small-company fund approach is an unfit and irrational method to develop a rate of return that must be supported by ratepayers.

The returns of 12.5% and 12.17%, both are predicated on data that is specific to large

companies - not small ones. This invalidates both returns because Dr. Andrews' analysis is based on "small publicly held" companies. Also, I have pointed to several places in the derivation of 12.5% and 12.17%, where Dr. Andrews is silent about the logic that led him to perform crucial procedures or where the procedure is irrational. Considering all these factors, Dr. Andrews' recommended range of 11.5% to 12.5% emerges as irrational.

Q. What is your opinion regarding Dr. Andrews' returns of 14.39%, 14.38%, 14.23%, 12.5%, 12.17% and 11.06%?

A. In my opinion, the returns of 14.39%, 14.38%, 14.23%, 12.5%, 12.17% and 11.06% are unsubstantiated, speculative and more than just and reasonable. They cannot be a basis for the TRA to set the equity return in this docket.

Q. How is your testimony different from that of the company's cost-of-capital witness?

A. In my opinion my testimony is different because I have used reasonable methods and achieved reasonable results. I have explained my methods in pain-staking detail, giving all parties an accurate and true description of all the factors and sources I considered when forming my opinion on the rate of return. Therefore, the equity return of 10.55% is neither confiscation nor extortion an is equitable to ratepayers and the company alike.

Q. Does this conclude your direct testimony?

A. Yes.

Proof of Comparability

Docket No 97-00982
Exhibit CA SNB___
Direct Testimony___
Schedule 1 ___
Page 1 of 1___

Market Statistics

NAME	Ratio of Market Price to Book Price Dec 1996	Equity Ratio Dec 1996	Dividend Yield Dec 1996	Value of Holdings Per Share Holder 4/30/97	Average Number Of Years Stock Is Held By Investor	Market Value 4/30/97 $(Millions)
AGL RESOURCES INC	180%	48 9%	5 40%	$63,334	3 36	1061
BAY ST GAS CO	150%	53 1%	5 61%	$30,949	3 86	343
BROOKLYN UN GAS CO	149%	55 8%	5 05%	$42,951	2 26	1352
INDIANA ENERGY INC	184%	62 5%	4 49%	$58,122	4 25	548
LACLEDE GAS CO	161%	57 1%	5 45%	$35,410	3 98	388
NORTHWEST NAT GAS CO	159%	52 5%	5 05%	$44,355	2 98	545
PEOPLES ENERGY CORP	171%	56 4%	5 42%	$34,172	2 21	1167
PIEDMONT NAT GAS INC	178%	49 7%	4 84%	$37,664	3 37	687
WASHINGTON GAS LT CO	174%	59 4%	5 19%	$45,226	2 98	972
AVERAGE	166%	55 0%	5 50%	$42,958	2 94	792

Financial Behavior

Value Line March 31, 1995 "We advise staying with top quality stocks with payout ratios below 80% We'd be wary of payout ratios above 80% "

▶ Companies Respond In Similar Way To Concerns Of The Financial Community

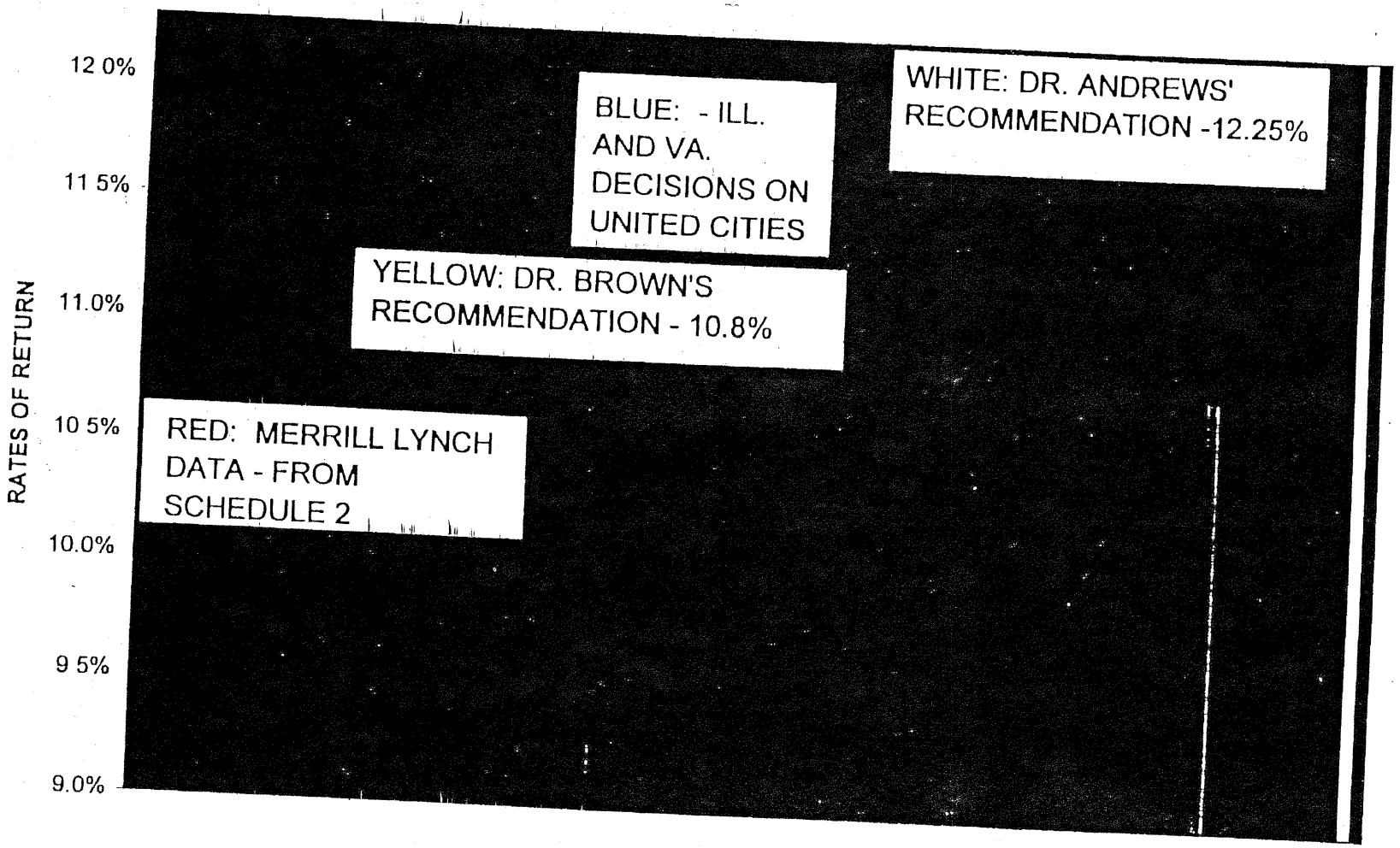
Dividends Payout Ratios As a Percent of Earnings

	1991	1992	1993	1994	1995	1996
AGL RESOURCES INC	98 1%	91 2%	96 3%	88 9%	78 2%	77 4%
BAY ST GAS CO	99 2%	96 5%	80 0%	77 8%	86 5%	76 0%
BROOKLYN UN GAS CO	87 6%	95 6%	76 3%	73 0%	73 2%	72 4%
INDIANA ENERGY INC	82 9%	82 8%	77 3%	66 7%	73 3%	59 4%
LACLEDE GAS CO	93 8%	102 6%	75 8%	85 9%	97 6%	67 4%
NORTHWEST NAT GAS CO	167 3%	155 0%	67 0%	72 1%	73 1%	60 9%
PEOPLES ENERGY CORP	83 4%	85 4%	84 4%	84 5%	101 1%	61 8%
PIEDMONT NAT GAS INC	97 8%	65 0%	65 5%	74 8%	73 8%	68 9%
WASHINGTON GAS LT CO	92 1%	84 3%	83 2%	78 2%	77 2%	61 6%
AVERAGE	97 9%	97 9%	80 7%	80 1%	83 3%	66 7%

Chart 1

Docket No 97-00982
Exhibit CA-SNB____
Direct Testimony___
Chart 1 of 3_____

ESTIMATIONS OF REQUIRED RATES OF RETURN TO EQUITY FOR AGL'S SUBSIDAIRY - CHATTANOOGA GAS



Merrill Lynch Data

MONTH	DCF RATE	RISK PREMIUM RATE	MAXIMUM OF THE TWO RATES
Jan-95	11 0%	10 4%	11 0%
Feb-95	10 6%	10 3%	10 6%
Mar-95	10 3%	10 2%	10 3%
Apr-95	10 2%	10 1%	10 2%
May-95	10 1%	10 0%	10 1%
Jun-95	10 1%	9 5%	10 1%
Jul-95	10 3%	9 3%	10 3%
Aug-95	10 5%	9 4%	10 5%
Sep-95	10 3%	9 3%	10 3%
Oct-95	10 3%	9 4%	10 3%
Nov-95	9 4%	9 6%	9 6%
Dec-95	9 8%	9 6%	9 8%
Jan-96	8 8%	9 2%	9 2%
Feb-96	8 8%	9 3%	9 3%
Mar-96	9 1%	9 3%	9 3%
Apr-96	9 9%	9 7%	9 9%
May-96	9 9%	9 6%	9 9%
Jun-96	10 0%	9 8%	10 0%
Jul-96	9 7%	9 7%	9 7%
Aug-96	10 0%	9 7%	10 0%
Sep-96	9 6%	9 9%	9 9%
Oct-96	9 6%	9 7%	9 7%
Nov-96	9 5%	9 5%	9 5%
Dec-96	10 4%	9 4%	10 4%
Jan-97	10 2%	10 6%	10 6%
Feb-97	10 2%	10 0%	10 2%
Mar-97	10 5%	10 1%	10 5%
Apr-97	10 5%	10 3%	10 5%
May-97	10 5%	10 1%	10 5%

Source *Merrill Lynch Quantitative Profiles* [Published Monthly]
January 1995 through May 1997 Issues, page 11

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Click here

United Cities granted rate increase in Illinois

03:24 p.m. Jun 26, 1997 Eastern

BRENTWOOD, Tenn.--(BUSINESS WIRE)--June 26, 1997--**United Cities Gas** Co. (NASDAQ:**UCIT**), a multistate distributor of natural and propane gas, announced today that the Illinois Commerce Commission has granted the company a rate increase of $428,000 in annual revenues.

An overall rate increase of 2.09 percent was granted for approximately 23,000 customers in or near Harrisburg, Metropolis, Vandalia, Virden and Salem, Ill. The rate increase provides **United Cities** with a 9.85 percent return on rate base and a 10.94 percent return on common equity. The increase is the result of an application filed before the Commission in November 1996.

The net rate increase is part of an agreement reached by **United Cities**, **Atmos Energy** Corporation and the Commission in approving the merger of **United Cities** and **Atmos**. In addition, the rate increase will be followed by a three year rate moratorium.

United Cities Gas Company distributes natural and propane gas to approximately 350,000 customers in 10 states. The company is also engaged in other energy-related businesses (See also http://www.businesswire.com)

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Exhibit CA-SNB____
Direct Testimony___
Schedule 4_____
Page 1 of 1____

United Cities granted rate increase in Virginia
05 03 p m Jun 02 1997 Eastern

BRENTWOOD Tenn --(BUSINESS WIRE)--June 2 1997--United Cities Gas Co (NASDAQ UCIT) a multistate distributor of natural and propane gas announced today that the Virginia State Corporation Commission has granted the company a rate increase of $102 838 in annual revenues by order dated May 27 1997

An overall rate increase of less than one percent was granted for approximately 18 000 current regulated customers The rate increase provides United Cities with a 10 percent return on rate base and an 11 percent return on common equity The increase is the result of an application filed before the Commission in April 1995

Due to the Commission's decision, money over-collected from customers since Sept. 28, 1995, when United Cities began charging interim rates based on its original 3 percent rate increase request, will be credited to customers' accounts with interest The credit amount for customers will vary according to their gas usage during the period interim rates were in effect

United Cities' last rate increase in Virginia was granted in 1989 Since that time rate reductions were implemented in both 1991 and 1994

United Cities Gas Company distributes natural and propane gas to approximately 350,000 customers in 10 states The company is also engaged in other energy-related businesses (See also http //www businesswire com)

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Effect of Monthly Compounding

	Monthly Net Income for Atlanta Gas-FY 1996 *	Monthly Income as a Percentage of Annual Income	Pattern of Monthly Return Based on Monthly Pattern of Income	Cumulative Equity Balance at Start of Month	Monthly Return on Equity	Cumulative Month End Equity Balance
			[col (3) X Allowed Annual Return of 10.55%]		[col (4) X col (5)]	
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Oct-95	3,272	4 1%	0 43%	$1.000	$0 0043	$1 004
Nov-95	9,492	11 8%	1 24%	$1.004	$0 0125	$1 017
Dec-95	17,476	21 7%	2 29%	$1.017	$0.0232	$1 040
Jan-96	18,120	22.5%	2 37%	$1.040	$0.0247	$1 065
Feb-96	14,495	18.0%	1.90%	$1 065	$0 0202	$1 085
Mar-96	13,797	17.1%	1 80%	$1.085	$0 0196	$1 104
Apr-96	5,232	6 5%	0 68%	$1 104	$0.0076	$1 112
May-96	0,836	1 0%	0 11%	$1 112	$0.0012	$1 113
Jun-96	-1,122	-1.4%	-0.15%	$1.113	-$0 0016	$1 112
Jul-96	2,226	2 8%	0.29%	$1.112	$0 0032	$1 115
Aug-96	-0,253	-0.3%	-0.03%	$1.115	-$0 0004	$1 114
Sep-96	-2,918	-3 6%	-0.38%	$1 114	-$0.0043	$1.110
Total	80,653	100 0%	10.55%		$0 1102	

*From CA Data Request 39

BEFORE THE TENNESSEE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: Docket No. 9502116

CHATTANOOGA GAS COMPANY

Tuesday, September 26, 1995
Hamilton County Board of Education
Chattanooga, Tennessee 37402

CROSS EXAMINATION OF DR. VICTOR L. ANDREWS

APPEARANCES:

COMMISSION MEMBERS:

Keith Bissell, Chairman,
Steve Hewlett and Sara Kyle

FOR THE CHATTANOOGA GAS COMPANY:

William L. Taylor, Jr., Esq., of
Spears, Moore, Rebman & Williams
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Chattanooga, Tennessee 37401

L. Craig Dowdy, Esq., of
Long, Aldridge & Norman
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Atlanta, Georgia 30308

FOR THE CONSUMER ADVOCATE:

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Consumer Advocate
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404 James Robertson Parkway
Nashville, Tennessee 37243-0500

Steven A. Hart, Esq.,
Special Counsel
450 James Robertson Parkway
Nashville, Tennessee 37243-0485

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dividends --

A Where are we?

Q I'm sorry, I've got the wrong page citations here. You can tell me whether you remember saying this or not. I can't find it through your testimony right now. In the case of public utilities dividends paid are constant for certain periods and are increased at irregular intervals even though financial processes underlying their movement may be progressing much more smoothly and constantly; does that sound correct?

A I think I would say smoothly and continuously, but whatever, but yes, that is true.

Q Do you agree --

A It's true as a general rule.

Q So you would agree that a public utility and natural gas public utility, their financial activity is basically smooth and continuous?

A Well, what I said, I think if we had the complete quotation would be that earnings and cash flows progress smoothly and continuously. Financial processes occur smoothly and continuously. They go -- if this makes the point for you -- minute by minute, hour by hour, day by day and they're not interruptable.

Q Just to clarify for the record we found the first segment that we didn't really dispute. It starts

CAPITAL STRUCTURE SUBMITTED IN DOCKET 95-02116
AS EXHIBIT 3 SCHEDULE 9

Docket No 97-00982
Exhibit CA-SNB____
Direct Testimony___
Schedule 8_____
Page 1 of 1____

CHATTANOOGA GAS COMPANY
Cost of Capital
For the 12 Months Ending September 30 1996

Line No		Amount	Ratio	Cost	Weighted Cost
1	Short Term Debt	5 190 953	5 36%	8 00%	0 43%
2	Long Term Debt	43 096 531	44 50%	7 96%	3 54%
3	Preferred Stock	4 183 753	4 32%	7 56%	0 33%
4	Common Stock Equity	44 374 900	45 82%	12 50%	5 73%
5	Total	96 846 137	100 00%		10 03%

DCF Recommended Return

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Direct Testimony___
Schedule 9 _____
Page 1 of 1_____

DCF SUGGESTED RATE OF RETURN

Company	12/96. Annual Dividend	Average Daily closing Price: 5/1/96 - 4/30/97	Annual Dividend Yield
Atlanta Gas	$1 06	$19.63	**5.40%**
Bay State	$1.52	$27.08	**5.61%**
Brooklyn Union	$1 42	$28.14	**5.05%**
Indiana Energy	$1 11	$24.70	**4.49%**
LaClede	$1 26	$23 11	**5.45%**
Northwest Natural	$1 20	$23 77	**5.05%**
Peoples	$1 83	$33.79	**5.42%**
Piedmont	$1.15	$23.76	**4.84%**
Washington Gas Light	$1 14	$21 94	**5.19%**
		Average Div. Yield	**5.17%**

	Year of AGL Dividend	
Actual	1996	**$1.06**
Value-Line Projection	2000	**$1.30**

AGL DIVIDEND GROWTH RATE	**5.23%**
DCF Suggested Rate of Return	**10.40%**

Exhibit CA-SNB
Direct Testimony
Schedule 10
Page 1 of 1

History of A Rated Bonds

1992		1993		1994		1995		1996		1997	
Jan 92	8 72%	Jan-93	8 13%	Jan 94	7 24%	Jan 95	8 75%	Jan-96	7 09%	Jan 97	7 93%
Feb	8 83%	Feb	7 80%	Feb	7 45%	Feb	8 55%	Feb	7 31%	Feb	7 81%
Mar	8 89%	Mar	7 81%	Mar	7 82%	Mar	8 40%	Mar	7 75%	Mar	8 08%
Apr	8 87%	Apr	7 66%	Apr	8 20%	Apr	8 31%	Apr	7 90%	Apr	8 23%
May	8 81%	May	7 75%	May	8 37%	May	7 71%	May	8 20%	May	
Jun	8 70%	Jun	7 59%	Jun	8 30%	Jun	7 60%	Jun	8 13%	Jun	
Jul	8 64%	Jul	7 43%	Jul	8 45%	Jul	7 72%	Jul	8 07%	Jul	
Aug	8 65%	Aug	7 16%	Aug	8 38%	Aug	7 84%	Aug	7 87%	Aug	
Sep	8 62%	Sep	6 94%	Sep	8 62%	Sep	7 55%	Sep	8 06%	Sep	
Oct	8 84%	Oct	6 91%	Oct	8 80%	Oct	7 36%	Oct	7 83%	Oct	
Nov	8 58%	Nov	7 25%	Nov	8 95%	Nov	7 30%	Nov	7 54%	Nov	
Dec	8 37%	Dec	7 28%	Dec	8 78%	Dec	7 10%	Dec	7 83%	Dec	
Average	8 727%	Average	7 459%	Average	8 278%	Average	7 562%	Average	7 782%	Average	8 01%

Average Most Recent 12 Months 7 948%

Sources Federal Reserve Bulletin, Table A26 Subtable 1 35, line 38
Federal Reserve Publications H15(518) and G13(415)

Risk Premium Data for Large Companies: 1925-1996

YEAR	Large Company Total Return Index For Year	Year-To-Year Percentage Change In Large Company Total Return Index
(1)	(2)	(3)
1925	1 00	
1926	1.12	11.60%
1927	1 54	37.54%
1928	2 20	43 58%
1929	2 02	-8.44%
1930	1 52	-24 88%
1931	0 86	-43.34%
1932	0 79	-8 15%
1933	1.21	53.87%
.....	.. .. ..	.....
.....	....	. ...
....	....	....
1988	406 46	16 81%
1989	534 46	31 49%
1990	517 50	-3.17%
1991	675 59	30 55%
1992	727 41	7 67%
1993	800.08	9 99%
1994	810 54	1 31%
1995	1113 92	37.43%
1996	1370 95	23 07%

If $1 Were Invested in 1925 and the Investment Grew by 10.7% Every Year, the Result Would Be $1370.95.

ACTUAL RETURN

10 7%

12 7%

BIASED RETURN

The Average Return, 12.7%, Says the Wealth Accumulated Since 1925 should be $4768. This is Inaccurate.

*Source: Ibbotson Associates 1997 Yearbook:
Column (2) - From Table B-1
Column (3) - From Table A-1

The Table Below Shows The Odds In 1996 Of Achieving The Actual Return
And The Biased Average Return From A $1 Investment In 1925 In A Large Company

	NUMBER OF POSSIBILITIES	ALL POSSIBLE VALUES OF INVESTMENT	ALL POSSIBLE RETURNS	ODDS OF ACHIEVING A RETURN EXACTLY EQUAL TO THE RETURN IN COLUMN (3)	ODDS OF ACHIEVING A RETURN LESS THAN THE RETURN IN COLUMN (3)	ODDS OF ACHIEVING A RETURN MORE THAN THE RETURN IN COLUMN (3)
	(1)	(2)	(3)	(4)	(5)	(6)
	1 0E+0	$0 00	-8 3%	0%	0%	100%
	71 0E+0	$0 00	-7 8%	0%	0%	100%
	2 5E+3	$0 00	-7 3%	0%	0%	100%
	57 2E+3	$0 01	-6 8%	0%	0%	100%
	46 2E+18	$82	6 4%	2%	3%	95%
	68 5E+18	$119	7 0%	3%	5%	92%
	95 8E+18	$173	7 5%	4%	8%	88%
	126 8E+18	$253	8 1%	5%	12%	83%
	158 5E+18	$368	8 7%	7%	17%	76%
	187 3E+18	$536	9 3%	8%	24%	68%
	209 3E+18	$780	9 8%	9%	32%	59%
	221 3E+18	$1,136	10 4%	9%	41%	50%
ACTUAL RETURN	----------	$1,370.95	10.7%	----------	50%	50%
	221 3E+18	$1,654	11 0%	9%	50%	41%
	209 3E+18	$2,409	11 6%	9%	59%	32%
	187 3E+18	$3,508	12 2%	8%	68%	24%
BIASED AVERAGE	----------	$4,768.40	12.7%	7%	75%	18%
	158 5E+18	$5,109	12 8%	7%	76%	17%
	126 8E+18	$7,440	13 4%	5%	83%	12%
	95 8E+18	$10,835	14 0%	4%	88%	8%
	68 5E+18	$15,778	14 6%	3%	92%	5%
	46 2E+18	$22,977	15 2%	2%	95%	3%
	29 4E+18	$33,460	15 8%	1%	97%	2%
	17 6E+18	$48,727	16 4%	1%	98%	1%
	10 0E+18	$70,959	17 0%	0%	99%	0%
	1 0E+0	$854,908,330	33 6%	0%	100%	0%

Chart 2

Docket No 97-00982
Exhibit CA-SNB____
Direct Testimony___
Chart 2 of 3_____

THE CUMULATIVE PROBABILITY DISTRIBUTION FOR IBBOTSON'S RETURNS TO LARGE COMPANY STOCKS

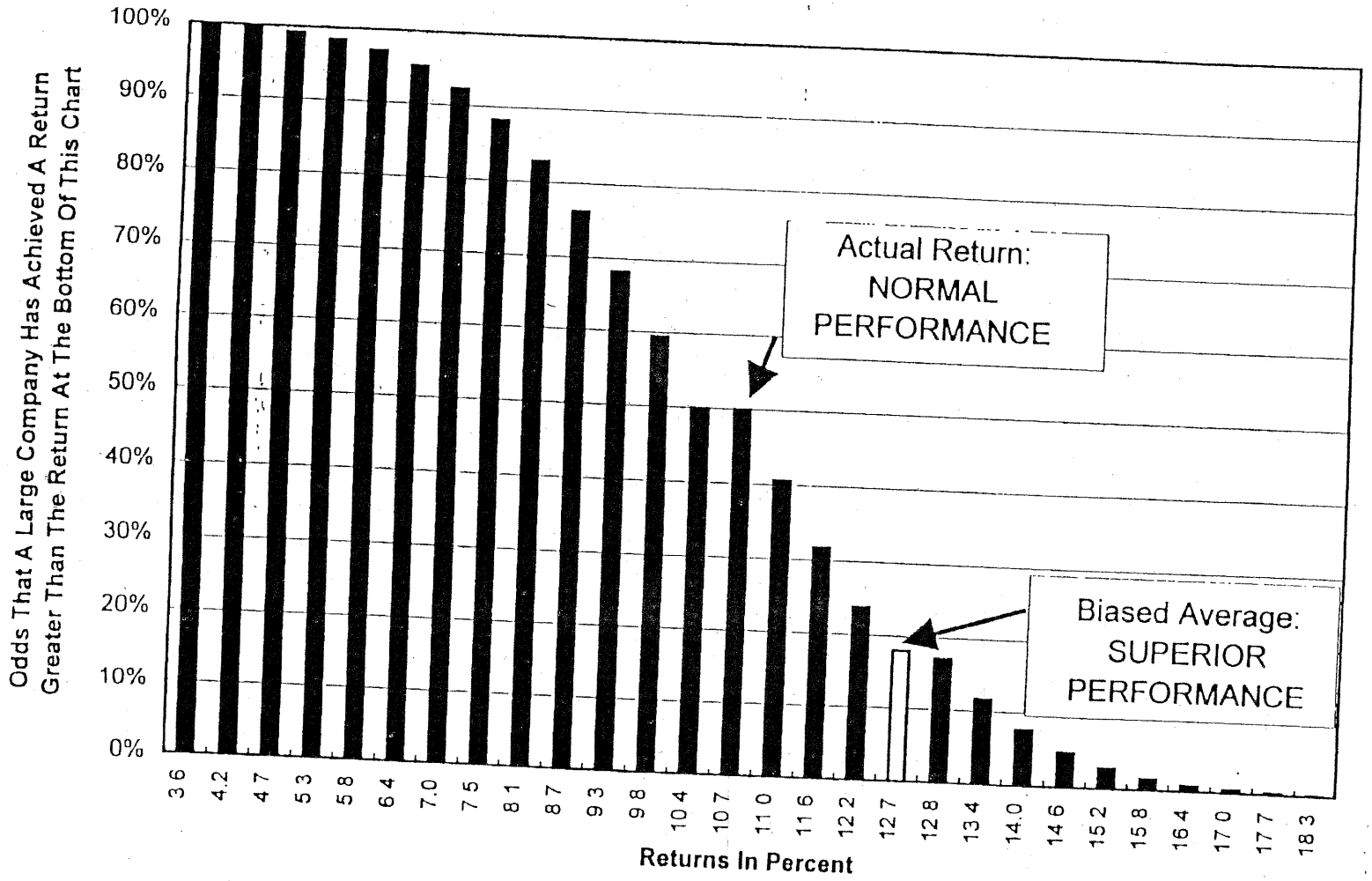
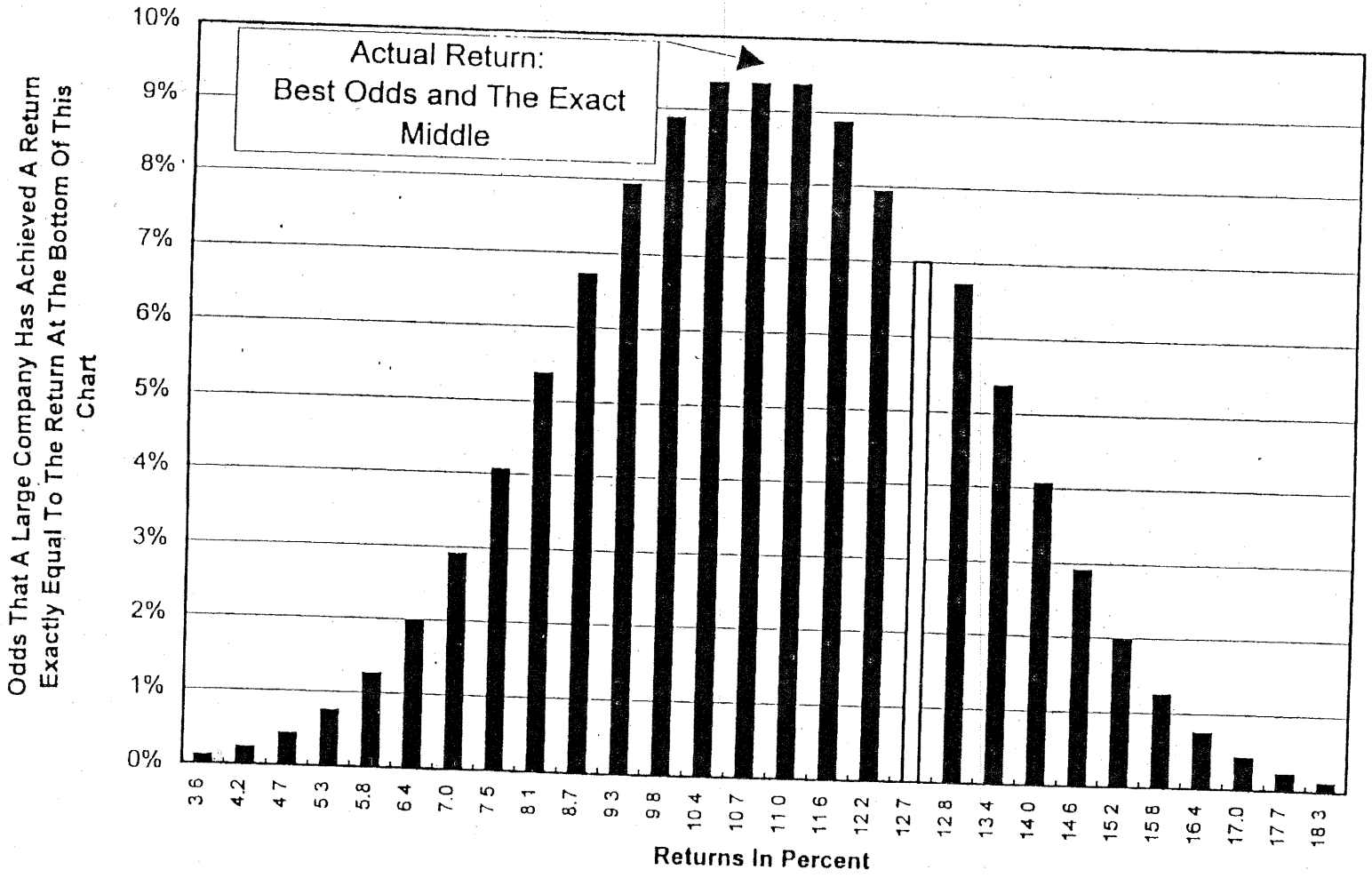


Chart 3

Docket No 97-00982
Exhibit CA-SNB____
Direct Testimony___
Chart 3 of 3_____

THE PROBABILITY DISTRIBUTION FOR IBBOTSON'S RETURNS TO LARGE COMPANY STOCKS



YEAR	T-Bill Total Return Index For Year	Year-To-Year Percentage Change In T-Bill Total Return Index	YEAR	T-Bill Total Return Index For Year	Year-To-Year Percentage Change In T-Bill Total Return Index
(1)	(2)	(3)	(4)	(5)	(6)
1925	1 00000		1961	1 60400	2 10%
1926	1 03300	3 30%	1962	1 64800	2 74%
1927	1 06500	3 10%	1963	1 70000	3 16%
1928	1 10300	3 57%	1964	1 76000	3 53%
1929	1 15500	4 71%	1965	1 82900	3 92%
1930	1 18300	2 42%	1966	1 91600	4 76%
1931	1 19600	1 10%	1967	1 99700	4 23%
1932	1 20700	0 92%	1968	2 10100	5 21%
1933	1 21100	0 33%	1969	2 23900	6 57%
1934	1 21300	0 17%	1970	2 38500	6 52%
1935	1 21500	0 16%	1971	2 49000	4 40%
1936	1 21700	0 16%	1972	2 58500	3 82%
1937	1 22100	0 33%	1973	2 76400	6 92%
1938	1 22100	0 00%	1974	2 98600	8 03%
1939	1 22100	0 00%	1975	3 15900	5 79%
1940	1 22100	0 00%	1976	3 31900	5 06%
1941	1 22200	0 08%	1977	3 48900	5 12%
1942	1 22500	0 25%	1978	3 74000	7 19%
1943	1 22900	0 33%	1979	4 12800	10 37%
1944	1 23300	0 33%	1980	4 59200	11 24%
1945	1 23700	0 32%	1981	5 26700	14 70%
1946	1 24200	0 40%	1982	5 82200	10 54%
1947	1 24800	0 48%	1983	6 33500	8 81%
1948	1 25800	0 80%	1984	6 95900	9 85%
1949	1 27200	1 11%	1985	7 49600	7 72%
1950	1 28700	1 18%	1986	7 95800	6 16%
1951	1 30600	1 48%	1987	8 39300	5 47%
1952	1 32800	1 68%	1988	8 92600	6 35%
1953	1 35200	1 81%	1989	9 67300	8 37%
1954	1 36400	0 89%	1990	10 42900	7 82%
1955	1 38500	1 54%	1991	11 01200	5 59%
1956	1 41900	2 45%	1992	11 39800	3 51%
1957	1 46400	3 17%	1993	11 72800	2 90%
1958	1 48600	1 50%	1994	12 18600	3 91%
1959	1 53000	2 96%	1995	12 87000	5 61%
1960	1 57100	2 68%	1996	13 54000	5 21%

Actual Return	3 74%	3 79%	Average Return

*Source Ibbotson Associates 1997 Yearbook
Column (2) - From Table B-5
Column (3) - From Table A-14
Column (5) - From Table B-5
Column (6) - From Table A-14

Debt Instruments: Actual and Average Returns

Returns of Debt Instruments 1925-1996

	Actual	Biased Average
Long-Term Corporate Bonds	5 60%	6 00%
Long-Term Government Bonds	5 10%	5.40%
Income Portion of Long-Term Government Bonds	5.10%	5.20%
Intermediate Term Government Bonds	5 20%	5 40%
U S. Treasury Bills	3 70%	3 80%

*Source: Ibbotson Associates 1997 Yearbook Page 118

Risk Premium Results

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Exhibit CA-SNB___
Direct Testimony___
Schedule 15 ____
Page 1 of 4_____

RISK PREMIUM ANALYSIS BETAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

BETA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	0 532	0 448	0 490	0 087	0 169	0 289	0 784	0 441	0 389	0 401
Jun-96	0 568	0 397	0 456	0 075	0 170	0 198	0 758	0 430	0 392	0 382
Jul-96	0 584	0 422	0 539	0 171	0 141	0 168	0 785	0 300	0 474	0 398
Aug-96	0 590	0 422	0 561	0 178	0 154	0 168	0 806	0 308	0 470	0 406
Sep-96	0 519	0 418	0 618	0 170	0 205	0 158	0 781	0 328	0 438	0 404
Oct-96	0 545	0 429	0 623	0 171	0 189	0 185	0 785	0 329	0 440	0 411
Nov-96	0 520	0 428	0 703	0 272	0 198	0 100	0 773	0 333	0 515	0 427
Dec-96	0 517	0 521	0 886	0 450	0 323	0 287	0 977	0 437	0 479	0 540
Jan-97	0 433	0 397	0 731	0 481	0 364	0 358	0 915	0 422	0 417	0 502
Feb-97	0 439	0 395	0 735	0 475	0 368	0 361	0 912	0 425	0 418	0 503
Mar-97	0 488	0 386	0 717	0 503	0 427	0 311	0 886	0 404	0 347	0 497
Apr-97	0 506	0 383	0 677	0 464	0 463	0 318	0 858	0 394	0 342	0 490
AV RECENT 12 MTHS	0 520	0 420	0 677	0 333	0 283	0 241	0 848	0 388	0 434	0 458

Risk Premium Results

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Direct Testimony___
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Page 2 of 4_____

RISK PREMIUM ANALYSIS T-STATISTICS OF BETAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

T-STATISTIC OF BETA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	2 569	2 402	2 305	0 361	0 930	1 483	3 222	2 276	1 875	1 934
Jun-96	2 609	2 039	2 073	0 276	0 897	0 988	3 064	2 110	1 791	1 761
Jul-96	2 739	2 203	2 463	0 625	0 764	0 874	3 231	1 468	2 160	1 836
Aug-96	2 712	2 200	2 525	0 652	0 831	0 871	3 261	1 498	2 152	1 856
Sep-96	2 355	2 213	2 935	0 636	1 129	0 828	3 184	1 678	2 033	1 888
Oct-96	2 428	2 280	3 005	0 644	1 036	0 958	3 223	1 689	2 044	1 923
Nov-96	2 321	2 284	3 417	1 069	1 094	0 522	3 189	1 720	2 413	2 003
Dec-96	2 113	2 559	3 935	1 656	1 670	1 406	3 747	2 035	2 047	2 352
Jan-97	1 813	1 870	3 442	1 820	2 025	1 821	3 525	2 006	1 798	2 236
Feb-97	1 842	1 869	3 438	1 791	2 035	1 829	3 515	2 016	1 804	2 238
Mar-97	2 087	1 880	3 435	1 934	2 362	1 612	3 482	1 975	1 535	2 256
Apr-97	2 208	1 929	3 286	1 810	2 591	1 761	3 435	1 970	1 544	2 282
AV RECENT 12 MTHS	2 316	2 129	3 188	1 264	1 554	1 248	3 379	1 805	1 853	2 093

Risk Premium Results

RISK PREMIUM ANALYSIS ALPHAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

ALPHA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-95	-0 003	0 000	0 001	0 007	0 004	0 000	-0 003	0 002	0 004	0 001
Jun-95	-0 003	0 002	0 002	0 009	0 003	0 003	-0 002	0 003	0 005	0 002
Jul-95	-0 003	0 001	0 000	0 005	0 003	0 002	-0 003	0 005	0 002	0 001
Aug-95	-0 002	0 001	0 002	0 006	0 004	0 002	-0 002	0 005	0 002	0 002
Sep-95	-0 003	-0 001	-0 001	0 004	0 003	0 001	-0 003	0 003	0 002	0 001
Oct-95	-0 002	-0 001	-0 001	0 004	0 002	0 001	-0 003	0 003	0 002	0 001
Nov-95	-0 003	-0 001	-0 002	0 001	0 002	0 002	-0 004	0 003	0 001	0 000
Dec-95	-0 002	-0 001	-0 003	0 000	0 002	0 001	-0 005	0 001	0 001	-0 001
Jan-96	-0 001	-0 002	-0 001	-0 001	0 000	0 000	-0 006	0 002	0 000	-0 001
Feb-96	-0 001	-0 002	-0 002	0 000	-0 001	-0 001	-0 006	0 001	0 000	-0 001
Mar-96	-0 003	-0 002	-0 001	0 000	-0 002	0 000	-0 005	0 002	0 002	-0 001
Apr-96	-0 002	-0 001	-0 001	0 000	-0 001	0 002	-0 005	0 002	0 002	-0 001
AV RECENT 12 MTHS	-0 002	-0 001	-0 001	0 003	0 002	0 001	-0 004	0 003	0 002	0 000

Risk Premium Results

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RISK PREMIUM ANALYSIS T-STATISTICS OF ALPHAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

T-STATISTIC OF ALPHA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	-0 452	-0 034	0 131	0 905	0 697	0 083	-0 447	0 337	0 577	0 200
Jun-96	-0 408	0 308	0 289	1 180	0 615	0 488	-0 324	0 508	0 705	0 373
Jul-96	-0 410	0 156	0 032	0 845	0 632	0 324	-0 488	0 822	0 335	0 228
Aug-96	-0 323	0 154	0 258	0 702	0 785	0 322	-0 287	0 902	0 302	0 313
Sep-96	-0 453	-0 118	-0 100	0 447	0 620	0 172	-0 381	0 466	0 346	0 111
Oct-96	-0 355	-0 111	-0 206	0 531	0 428	0 189	-0 437	0 473	0 360	0 097
Nov-96	-0 399	-0 098	-0 360	0 068	0 407	0 398	-0 497	0 439	0 215	0 019
Dec-96	-0 358	-0 216	-0 500	0 063	0 421	0 181	-0 717	0 152	0 082	-0 099
Jan-97	-0 191	-0 333	-0 207	-0 141	-0 050	-0 074	-0 822	0 270	0 067	-0 164
Feb-97	-0 189	-0 368	-0 310	0 036	-0 098	-0 165	-0 738	0 171	0 014	-0 183
Mar-97	-0 378	-0 290	-0 208	-0 040	-0 293	0 076	-0 659	0 309	0 313	-0 130
Apr-97	-0 344	-0 189	-0 229	-0 059	-0 269	0 278	-0 685	0 267	0 333	-0 100
AV RECENT 12 MTHS	-0 355	-0 095	-0 117	0 361	0 325	0 189	-0 540	0 426	0 304	0 055

Risk Premium Suggested Rate Of Return

COMPANY	Debt Yield (a)	Beta (b)	Market Risk Premium = 10 7% - 3 7% (c)	Company Risk Premium (d)=(b)X(c)	Company Equity Cost (e)=(a)+(d)
AGL RESOURCES INC (HLDG CO)	7 95%	0 520	6 97%	3 62%	11 57%
BAY ST GAS CO	7 95%	0 420	6 97%	2 93%	10 88%
BROOKLYN UN GAS CO	7.95%	0 677	6 97%	4 72%	12 67%
INDIANA ENERGY INC	7 95%	0 333	6 97%	2 32%	10 27%
LACLEDE GAS CO	7 95%	0 283	6 97%	1 98%	9 92%
NORTHWEST NAT GAS CO	7 95%	0 241	6 97%	1 68%	9 63%
PEOPLES ENERGY CORP	7 95%	0 848	6 97%	5 91%	13 86%
WASHINGTON GAS LT CO	7 95%	0 368	6 97%	2 57%	10 51%
PIEDMONT NATURAL GAS CO	7 95%	0 434	6 97%	3 02%	10 97%
** Av of Comparable Cos	7 95%	0 458	6 97%	0 032	11 14%

**Average Includes All Betas for All Companies Because the Average T-Statistics Are Greater Than 1 T-Statistics Are Shown In The Prior Schedule

Risk Premium Suggested Rate Of Return	11.14%

Any Model Relying on Ibbotson's Data Uses Monthly Compounding

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Ibbotson's Annual Returns Are Based on Monthly Compounding

ROW	Month	Monthly Return	Monthly Return Relative to the Value "1"	Cumulative Return in the Year Relative to the Value "1"	Cumulative Return in the Year
	(1)	(2)*	(3)	(4)	(5)
				col (3) x prior entry in col (3)	
-	-	-	100 00%		
1	1/1/96	3.44%	103 44%	103 44%	3.44%
2	2/1/96	0.96%	100 96%	104.43%	4.43%
3	3/1/96	0 96%	100 96%	105 44%	5 44%
4	4/1/96	1.47%	101.47%	106.99%	6 99%
5	5/1/96	2 58%	102.58%	109.75%	9.75%
6	6/1/96	0.41%	100.41%	110 20%	10.20%
7	7/1/96	-4 45%	95.55%	105 29%	5 29%
8	8/1/96	2.12%	102.12%	107 52%	7 52%
9	9/1/96	5.62%	105 62%	113 57%	13 57%
10	10/1/96	2.74%	102 74%	116 68%	16.68%
11	11/1/96	7.59%	107.59%	125 53%	25 53%
12	12/1/96	-1 96%	98 04%	123.07%	23.07%

*Source: Ibbotson Associates 1997 Yearbook Page 181, Table A-1 for 1996

CHATTANOOGA GAS COMPANY

Office of the Consumer Advocate Interrogatory/Data Request - June 4, 1997

Item 42

42. Q. With regard to Exhibit 5 Schedule 9 of the company's filing, show the calculations and provide the data used to develop the figures shown under the column headings "Amount", "Ratio" and "Cost".

A. See attached documentation.

AGL Resources
Projected Capitalization Ratios

	1997	1998	Average	Ratio
Short Term Debt	69,620	81,537	75,579	5.28%
Long Term Debt	659,500	659,500	659,500	46.07%
Preferred Stock	58,469	70,090	64,280	4.49%
Common Stock Equity	619,302	644,902	632,102	44.16%
	1,406,891	1,456,029	1,431,461	100.00%

Chattanooga Gas Company
Test Year Projected Capitalization

	Ratio	Amount
Short Term Debt	5.28%	5,060,518
Long Term Debt	46.07%	44,154,936
Preferred Stock	4.49%	4,303,357
Common Stock Equity	44.16%	42,324,333
	100.00%	95,843,144

AGL Resources
Projected Cost of Capital Components

Long Term Debt	
Projected Balance	659,500,000
Less: Unamortized Loss on Repurchase	1,585,136
Less: Unamortized Debt Discount & Expense	3,702,500
Net Projected Balance	654,212,364
Projected Interest Cost	50,730,000
Projected Cost Rate	7.75%
Short Term Debt	
Projected Average Monthly Balance	49,900,000
Projected Interest Cost	2,892,000
Projected Cost Rate	5.80%
Preferred Stock	
Projected Balance	64,280,000
Projected Dividend Accrual	4,525,000
Projected Cost Rate	7.04%
Common Stock Equity	
Projected Cost Rate	
See Cost of Equity Testimony & Exhibits	12.25%

Recommended Over All Return

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		Ratio	Cost	Weighted Cost
1	Short-Term Debt	5 28%	5 80%	0.31%
2	Long-Term Debt	46 07%	7 75%	3 57%
3	Preferred Stock	4 49%	7.04%	0.32%
4	Common Equity	44 16%	10 55%	4.66%
5	Total	100.00%		8 85%

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Standish Small Cap Equity	Small Company	SDSCX	$Closed	9 51	17 36
T Rowe Price Small-Cap Val	Small Company	PRSVX	$Closed	10 36	24 61
MAS Small Cap Value	Small Company	MPSCX	$Closed	9 47	35 15
Montgomery Small Cap R	Small Company	MNSCX	$Closed	12 11	18 69
MFS Aggr Small Cap Eq A	Small Company	MASCX	$Closed	14 24	15 45
Artisan Small Cap	Small Company	ARTSX	$Closed	10 68	11 86
Pioneer Small Company A	Small Company	PSCFX	$Closed	5 07	24 15
Pioneer Small Company B	Small Company	PBSCX	$Closed	5 07	23 21
Pioneer Small Company C	Small Company	PCSCX	$Closed	5 07	n/a
PIMCo Small Cap Growth Instl	Small Company	PSCIX	$Closed	11 07	16 83
GMO Small Cap Value III	Growth	GMSVX	$35,000,000	0	20 16
UAM ICM Small Company	Small Company	ICSCX	$5,000,000	8 89	23 01
Benchmark Small Co Index A	Small Company	BSCAX	$5,000,000	9 37	15 97
Bear Stearns Small Cap Val Y	Small Company	BSVYX	$2,500,000	7 57	15 87
DFA United Kingdom Small Co	Europe Stock	DFUKX	$2,000,000	19 98	29 81
DFA U S Small Cap Value	Small Company	DFSVX	$2,000,000	7 01	22 33
DFA Japanese Small Company	Pacific Stock	DFJSX	$2,000,000	4 35	-22 78
DFA Pacific Rim Small Compny	Pacific Stock	DFRSX	$2,000,000	25 72	14 36
DFA Continental Small Compny	Europe Stock	DFCSX	$2,000,000	14 28	14 32
DFA U S 6-10 Small Company	Small Company	DFSTX	$2,000,000	9 11	17 68
DFA U.S. 9-10 Small Company	Small Company	DFSCX	$2,000,000	8.75	17 65
DFA Intl Small Cap Value	Foreign Stock	DISVX	$2,000,000	10 57	0 95
Lazard Small Cap Instl	Small Company	LZSCX	$1,000,000	8 3	23 93
JPM Instl U S Small Company	Small Company	JUSSX	$1,000,000	9 6	20 84
Crabbe Huson Small Cap Instl	Small Company	CHISX	$1,000,000	3 97	n/a
Lazard Intl Small Cap Instl	Foreign Stock	LZISX	$1,000,000	16 2	15 65
ITT Hartford Small Company Y	Small Company	n/a	$1,000,000	0	n/a
Enterprise Small Co Value Y	Small Company	EIGYX	$1,000,000	7 81	11 83
Munder Small Company Grth Y	Small Company	MULYX	$500,000	11 25	37 17
Compass Small Cap Grth Instl	Small Company	PSGIX	$500,000	11 64	31 58
Compass Small Cap Val Instl	Small Company	PNSEX	$500,000	8 25	19 87
Nations Small Cap Gr Prim A	Small Company	PSCPX	$500,000	9 34	20 72
TCW Galileo Small Cap Growth	Small Company	n/a	$250,000	10 8	17 54
Emerald Small Cap Instl	Small Company	EMSCX	$250,000	10 14	10 69
Hancock Small Cap Equity	Small Company	n/a	$250,000	12 49	13 48
PIMCo Small Cap Value Instl	Small Company	PSVIX	$200,000	9 19	27 72
PIMCo Small Cap Value Admin	Small Company	n/a	$200,000	9 19	27 37
PIMCo Small Cap Growth Admin	Small Company	n/a	$200,000	11 41	16 71
JPM Pierpont U S Small Co	Small Company	PPCAX	$100,000	9 63	20 75
Parkstone Small Cap Instl	Small Company	PKSCX	$100,000	11 45	27 7

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Standish Small Cap Tax-Sen	Small Company	SDCEX	$100,000	11 06	21 23
Turner Small Cap Equity	Small Company	TSCEX	$100,000	11 24	28 85
Avesta Small Capitalization	Small Company	n/a	$100,000	10 78	30 95
Berger Small Cap Value Inst	Small Company	OMNIX	$100,000	8 28	25 6
Kent Small Co Growth Instl	Small Company	KNEEX	$100,000	8 95	19 61
SEI Instl Small Cap Growth A	Small Company	SSCGX	$100,000	10 96	19 14
SEI Instl Small Cap Growth A	Small Company	SSCGX	$100,000	10 96	19 14
59 Wall St Small Company	Small Company	FNSMX	$100,000	10 42	19 12
SEI Instl Small Cap Value A	Small Company	SESVX	$100,000	8	22 13
DLB Global Small Cap	World Stock	DLBSX	$100,000	15 07	9 85
Pictet Intl Small Companies	Foreign Stock	PTSCX	$100,000	14 65	n/a
Rainier Small/Mid Cap Equity	Growth	RIMSX	$25,000	9 37	22 56
Glenmede Small Cap Equity	Small Company	GTCSX	$25,000	9 33	25 1
Target Small Cap Value	Small Company	TASVX	$25,000	9 17	21 84
Target Small Cap Growth	Small Company	TASGX	$25,000	12 36	18 88
Schroder Small Cap	Small Company	WSCVX	$25,000	8 92	23 91
UAM FMA Small Company	Small Company	FMACX	$25,000	8 52	26 2
Quaker Small-Cap Value	Small Company	n/a	$25,000	0	n/a
Hotchkis & Wiley Small Cap	Small Company	HWSCX	$10,000	9 34	14 27
Longleaf Partners Small-Cap	Small Company	LLSCX	$10,000	8 12	30 64
LKCM Small Cap Equity	Small Company	LKSCX	$10,000	8 61	26 95
LKCM Small Cap Equity	Small Company	LKSCX	$10,000	8 61	26 95
CRM Small Cap Value	Small Company	CRMSX	$10,000	5 46	38 95
RCM Small Cap	Small Company	n/a	$10,000	9 71	34 41
Brazos/JMIC Small Cap Growth	Small Company	BJSCX	$10,000	0	n/a
Stratton Small-Cap Yield	Small Company	STSCX	$5,000	9 7	14 97
Compass Small Cap Grth Svc	Small Company	PCGEX	$5,000	11 64	31 39
Compass Small Cap Val Svc	Small Company	PSESX	$5,000	8 25	19 56
Prudential Small Companies C	Small Company	n/a	$5,000	9 09	22 97
Tocqueville Small Cap Val A	Small Company	TSCVX	$5,000	9 78	25 03
PBHG Strategic Small Co PBHG	Small Company	PSSCX	$5,000	0	n/a
Vanguard Index Small Cap Stk	Small Company	NAESX	$3,000	9 32	18 12
Galaxy II Small Co Index Ret	Small Company	ISCIX	$2,500	10 27	19 66
Vista Small Cap Equity A	Small Company	VSEAX	$2,500	10 4	28 8
Vista Small Cap Equity B	Small Company	VSEBX	$2,500	10 4	27 93
T Rowe Price Small Cap Stk	Small Company	OTCFX	$2,500	10 41	21 05
Dreyfus Small Company Value	Small Company	DSCVX	$2,500	7 65	34 15
Galaxy Small Co Equity Ret A	Small Company	GASEX	$2,500	11 05	20 84
BT Investment Small Cap	Small Company	BTSCX	$2,500	11 18	6 9
Scudder Small Company Value	Small Company	SCSUX	$2,500	8 61	23 84

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Warburg Pincus Small Val Com	Small Company	WPSVX	$2,500	8 52	56 2
Galaxy Small Cap Value Ret A	Small Company	SSCEX	$2,500	9 21	26 84
Fidelity Small Cap Stock	Small Company	FDSCX	$2,500	11 18	13 63
Northern Small Cap	Small Company	NOSGX	$2,500	6 92	18 93
Strong Small Cap	Small Company	SCAPX	$2,500	10 12	22 7
Fidelity Japan Small Co	Pacific Stock	FJSCX	$2,500	7 67	-24 59
PIC Small Cap Growth	Small Company	PISCX	$2,000	11 78	18 2
Bridgeway Ultra-Small Co	Small Company	BRUSX	$2,000	10 44	29 74
Sit Small Cap Growth	Small Company	SSMGX	$2,000	12 65	14 97
AARP Small Company Stock	Small Company	ASCSX	$2,000	0	n/a
Columbia Small Cap	Small Company	CMSCX	$2,000	9	n/a
FBR Small Cap Financial	Sp -Financial	n/a	$2,000	8	n/a
FBR Small Cap Growth/Value	Small Company	n/a	$2,000	16 61	n/a
Crabbe Huson Small Cap Prim	Small Company	CHSCX	$2,000	3 97	n/a
Rembrandt Small Cap Inv	Small Company	n/a	$2,000	13 9	19 18
Clover Capital Small Cap Val	Small Company	n/a	$2,000	5 92	n/a
Fremont Intl Small Cap	Foreign Stock	FRISX	$2,000	11 81	12 15
Berger Small Company Growth	Small Company	BESCX	$2,000	11 14	16 77
Federated Small Cap Strat B	Small Company	SMCBX	$1,500	13 04	34 16
Federated Small Cap Strat C	Small Company	SMCCX	$1,500	13 04	33 99
Federated Intl Small Co B	Foreign Stock	ISCBX	$1,500	13 73	n/a
Federated Intl Small Co C	Foreign Stock	ISCCX	$1,500	13 73	n/a
Norwest Advant Small Co Gr I	Small Company	NVSCX	$1,000	8 48	19 82
Colonial Small Cap Value A	Small Company	CSMIX	$1,000	11 02	18 35
Colonial Small Cap Value B	Small Company	CSSBX	$1,000	11 02	17 84
Heritage Small Cap Stock A	Small Company	HRSCX	$1,000	11 71	27 46
Parkstone Small Cap Inv A	Small Company	PKSAX	$1,000	11 45	27 59
Heritage Small Cap Stock C	Small Company	HSCCX	$1,000	11 71	26 45
Parkstone Small Cap Inv C	Small Company	n/a	$1,000	11 45	26 24
Parkstone Small Cap Inv B	Small Company	PKSBX	$1,000	11 45	26 62
Westcore Small-Cap Opport	Small Company	WTSCX	$1,000	8 28	25 58
Goldman Sachs Small Cap Eq A	Small Company	GSSMX	$1,000	6 13	21 84
Goldman Sachs Small Cap Eq B	Small Company	GSQBX	$1,000	6 13	n/a
Gabelli Small Cap Growth	Small Company	GABSX	$1,000	7 54	11 88
Accessor Small to Mid Cap	Small Company	ASMCX	$1,000	11 8	24 74
Munder Small Company Grth A	Small Company	MULAX	$1,000	11 25	36 83
Norwest Advant Small Cap I	Small Company	NVSOX	$1,000	0	n/a
Munder Small Company Grth C	Small Company	n/a	$1,000	11 25	36 23
Munder Small Company Grth B	Small Company	MULBX	$1,000	11 25	35 9
Kemper-Dreman Small Cap A	Small Company	KDSAX	$1,000	8 94	29 6

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
ESC Strategic Small Cap A	Small Company	ESCAX	$1,000	9 67	27 43
Kemper-Dreman Small Cap C	Small Company	KDSCX	$1,000	10	29 94
Kemper-Dreman Small Cap B	Small Company	KDSBX	$1,000	8 94	28 54
ESC Strategic Small Cap D	Small Company	ESCDX	$1,000	9 67	26 83
SSgA Small Cap	Small Company	SVSCX	$1,000	11 43	28 79
Bear Stearns Small Cap Val A	Small Company	BSVAX	$1,000	7 57	15 43
Bear Stearns Small Cap Val C	Small Company	BSVCX	$1,000	7 57	14 83
BB&T Small Company Growth A	Small Company	BBBSX	$1,000	11 59	30 77
BB&T Small Company Growth B	Small Company	n/a	$1,000	11 59	30 98
Montgomery Intl Small Cap R	Foreign Stock	MNISX	$1,000	23 45	14 97
Oakmark Small Cap	Small Company	OAKSX	$1,000	8 82	39 79
Kent Small Co Growth Invmt	Small Company	KNEMX	$1,000	8 95	19 15
TCW/DW Small Cap Growth	Small Company	TCSCX	$1,000	11 33	13 71
Invesco European Small Co	Europe Stock	IVECX	$1,000	21 04	31 03
Harris Ins Small-Cap Instl	Small Company	HSCIX	$1,000	10 57	n/a
Harris Ins Small-Cap A	Small Company	n/a	$1,000	10 57	n/a
HSBC Small Cap	Small Company	MSCFX	$1,000	11 9	15 29
Prudential Small Companies A	Small Company	PGOAX	$1,000	9 09	23 92
Schwab Small Cap Index	Small Company	SWSMX	$1,000	9 72	15 49
SEI Instl Small Cap Growth D	Small Company	n/a	$1,000	10 96	18 75
PIMCo Small Cap Value A	Small Company	PCVAX	$1,000	0	n/a
PIMCo Small Cap Value B	Small Company	PCVBX	$1,000	0	n/a
PIMCo Small Cap Value C	Small Company	PCVCX	$1,000	0	n/a
Pegasus Small Cap Opport I	Growth	PSOPX	$1,000	10 56	25 63
Pegasus Small Cap Opport A	Growth	n/a	$1,000	10 56	24 59
Pegasus Small Cap Opport B	Growth	n/a	$1,000	10 56	24 42
Prudential Small Companies B	Small Company	CHNDX	$1,000	9 09	22 97
Evergreen Small Cap Eq Inc Y	Small Company	ESCEX	$1,000	11 29	22 38
Value Line Small-Cap Growth	Small Company	VLSCX	$1,000	11 24	10 35
Evergreen Small Cap Eq Inc A	Small Company	n/a	$1,000	11 29	22 01
Evergreen Small Cap Eq Inc B	Small Company	n/a	$1,000	11 29	21 1
Evergreen Small Cap Eq Inc C	Small Company	n/a	$1,000	11 29	21 1
Norwest Advant Small Co StkA	Small Company	NCSAX	$1,000	12 77	25 98
Norwest Advant Small Co Stkl	Small Company	NSCTX	$1,000	12 77	26 03
Norwest Advant Small Co StkB	Small Company	NCSBX	$1,000	12 77	24 91
Arch Small Cap Equity Inv A	Small Company	EMGRX	$1,000	9 87	10 5
Invesco Small Company Value	Small Company	IDSCX	$1,000	9 18	12 46
Preferred Small Cap	Small Company	PSMCX	$1,000	11 78	20 46
Heartland Small Cap Contrar	Small Company	HRSMX	$1,000	10	18 86
Arch Small Cap Equity Inv B	Small Company	n/a	$1,000	9 87	9 82

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
North American Small/Mid A	Growth	NSMAX	$1,000	11 94	n/a
North American Small/Mid C	Growth	NSMCX	$1,000	11 94	n/a
North American Small/Mid B	Growth	NSMBX	$1,000	11 94	n/a
Aetna Small Company Sel	Small Company	AESGX	$1,000	10 1	13 62
Gateway Small Cap Index	Small Company	GSCIX	$1,000	9 13	17 04
Invesco Small Company Growth	Small Company	FIEGX	$1,000	12 21	11 62
Aetna Small Company Adv	Small Company	AESAX	$1,000	10 1	12 79
Safeco Small Co Stock NoLoad	Small Company	SFSCX	$1,000	8 08	n/a
PaineWebber Small Cap A	Small Company	PSCAX	$1,000	10 94	17 16
Eastcliff Regional Small Cap	Small Company	EARSX	$1,000	10 12	n/a
PaineWebber Small Cap B	Small Company	PSCBX	$1,000	10 94	16 2
PaineWebber Small Cap C	Small Company	PSCDX	$1,000	10 94	16 22
AAL Small Cap Stock A	Small Company	AASMX	$1,000	9 21	n/a
ITT Hartford Small Company A	Small Company	IHSAX	$1,000	11 36	n/a
ITT Hartford Small Company B	Small Company	n/a	$1,000	0	n/a
Marshall Small-Cap Growth	Small Company	MRSCX	$1,000	0	n/a
Emerald Small Cap Ret	Small Company	n/a	$1,000	10 14	10 05
Keystone Small Co Grth II A	Small Company	KSGAX	$1,000	10 34	n/a
Keystone Small Co Grth II B	Small Company	KSGBX	$1,000	10 34	n/a
Keystone Small Co Grth II C	Small Company	KSGCX	$1,000	10 34	n/a
Dean Witter Intl Small Cap	Foreign Stock	DWISX	$1,000	21 66	1 01
Keystone Small Co Grth (S-4)	Aggressive Growth	KSFOX	$1,000	12 67	0 82
Enterprise Small Co Value A	Small Company	ENSPX	$1,000	7 81	11 28
Kemper Small Cap Equity A	Small Company	KSCAX	$1,000	10 41	14 09
Enterprise Small Co Value B	Small Company	ESCBX	$1,000	7 81	10 77
Kemper Small Cap Equity B	Small Company	KSCBX	$1,000	10 41	12 84
Kemper Small Cap Equity C	Small Company	KSCCX	$1,000	10 41	12 86
Sentinel Small Company A	Small Company	SAGWX	$1,000	10 49	21 3
Sentinel Small Company B	Small Company	n/a	$1,000	10 49	n/a
SunAmerica Small Co Grth A	Small Company	SEGAX	$500	10 23	14 92
SunAmerica Small Co Grth B	Small Company	SEGBX	$500	10 23	14 12
Compass Small Cap Grth Inv A	Small Company	CSGEX	$500	11 64	31 13
Compass Small Cap Val Inv A	Small Company	PSEIX	$500	8 25	19 34
Phoenix Small Cap A	Small Company	PHSAX	$500	12 38	29 96
Federated Small Cap Strat A	Small Company	SMCAX	$500	13 04	35 04
Qualivest Small Comps Val A	Small Company	QSVAX	$500	9 89	20 07
Phoenix Small Cap B	Small Company	PHSCX	$500	12 38	28 93
Qualivest Small Comps Val C	Small Company	n/a	$500	9 89	19 35
RIMCo Monument Small Cap Eq	Small Company	RISCX	$500	10 1	21 92
Federated Intl Small Co A	Foreign Stock	ISCAX	$500	13 73	n/a

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
ONE Fund Small Cap	Small Company	n/a	$500	9 34	17 01
GT Global Amer Small Cap Adv	Small Company	n/a	$500	8 85	14 22
GT Global Amer Small Cap A	Small Company	GTSAX	$500	8 85	13 81
GT Global Amer Small Cap B	Small Company	GTSBX	$500	8 85	13 14
First Omaha Small Cap Value	Small Company	n/a	$500	8 52	n/a
Alger Small Capitalization A	Small Company	n/a	$500	12 59	n/a
Alger Small Capitalization B	Small Company	ALSCX	$500	12 59	4 17
Winthrop Small Company Val A	Small Company	WFAGX	$250	9 6	14 58
Keeley Small Cap Value	Small Company	KSCVX	$250	7 83	25 99
Piper Small Company Growth A	Small Company	PJSCX	$250	9 2	11 65
Franklin Small Cap Grth I	Small Company	FRSGX	$100	10 31	27 07
Franklin Small Cap Grth II	Small Company	FRSIX	$100	10 31	26 07
Templeton Global Small Co I	World Stock	TEMGX	$100	18	22 09
Templeton Global Small Co II	World Stock	TESGX	$100	18	21 35
Munder Small Company Grth K	Small Company	MULKX	$0	11 25	36 89
Landmark Small Cap Equity A	Small Company	LSCEX	$0	9 44	37 8
Alger Small Cap Retirement	Small Company	ALSRX	$0	12 02	14 83
Galaxy Small Co Equity Tr	Small Company	GSETX	$0	11 05	21 59
BB&T Small Company Growth Tr	Small Company	BBCGX	$0	11 59	31 19
DFA U S Small Cap Value II	Small Company	DFAVX	$0	7 01	22 07
Warburg Pincus Adv Small Val	Small Company	n/a	$0	8 52	57
Qualivest Small Comps Val Y	Small Company	QSVYX	$0	9 89	20 36
Prudential Small Companies Z	Small Company	PSCZX	$0	9 09	n/a
Pacific Advisors Small Cap	Small Company	PASMX	$0	10 89	43 7
Galaxy Small Cap Value Tr	Small Company	SMCEX	$0	9 21	27 19
Arch Small Cap Equity Tr	Small Company	n/a	$0	9 87	10 98
Arch Small Cap Equity Instl	Small Company	n/a	$0	9 87	10 62
Rembrandt Small Cap Tr	Small Company	RSMCX	$0	13 9	19 42
SEI Instl Inv Small Cap	Small Company	n/a	$0	9 56	n/a
Kemper Small Cap Equity I	Small Company	n/a	$0	10 41	14 54
Brown Capital Small Co Instl	Small Company			10 44	

Morning Star Report on DFA 9-10 Fund

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DFA U.S. 9-10 Small Company
(Data as of 05-31-97)

Investment Objective	Rating	Load	Yield	Assets ($mil)	NAV
Small Company	**	None	0 21%	1107.8	11.65

DFA U.S. 9-10 Small Company Portfolio seeks long-term capital appreciation.

The fund invests in a diverse group of small companies with readily marketable securities. These companies may be traded on the NYSE, the AMEX, or the over-the-counter market, but their market capitalizations must be comparable with those in the smallest quintile of the NYSE The portfolio is rebalanced at least semiannually.

The fund is designed primarily for institutional investors Prior to April 10, 1989, the fund was named DFA Investment Dimensions Small Company Prior to 1983, the fund was named DFA Small Company.

Performance: Annual Return %

	YTD	1996	1995	1994	1993
DFA U S. 9-10 Small Company	4.02	17.65	34.48	3.09	20.97
S&P 500 Index	15.43	22 95	37 53	1 32	10 06

These Figures Match DFA's and Dr. Andrews' Numbers in his Schedule 6, page 1, Far-left Column

Performance: Trailing Return %

	1 Mo	3 Mo	1 Yr	3 Yr Avg	5 Yr Avg
DFA U.S 9-10 Small Company		10 22	1.92	-1.33	18 60	18 41
S&P 500 Index		6.08	7.80	29 40	25.92	18.36

Risk Measures

Morningstar Risk:	Above Avg.	Beta (3 Yr)	0 78

Morning Star Report on DFA 9-10 Fund

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Morningstar Return: Average Std. Deviation (3 Yr) 16 59
R-Squared 32

Top Ten Portfolio Holdings
(Data as of 02-28-97)

Ticker	Amount 000	Security	Value $000	% Net Assets
KUH	186	Kuhlman	4380	0.38
GLE	117	Gleason	4187	0 36
INVX	179	Innovex	3844	0.33
FRC	157	First Republic Bancorp	3654	0.32
ROG	128	Rogers	3459	0 30
HEI	133	HEICO	3430	0.30
CULP	179	Culp	3214	0.28
CDSI	105	Computer Data Systems	3193	0.28
ELMG	142	Electromagnetic Sciences	3173	0.27
APR	160	American Precision Inds	3027	0.26

Portfolio Statistics

Price/Earnings Ratio 21.64
Price/Book Ratio. 2 80
Return on Assets %· 8.75
Median Market Cap ($mil) 123.29

Income Ratio %· 0.22
Turnover Ratio %· 23 68
Expense Ratio %. 0 61

This figure, 8.75%, is not provided in DFA's Annual Report See Schedule 22, page 2.

These figures are the same as those reported in DFA's 1996 Annual Report

Expenses and Fees

Front-End Load· 0.00
Deferred Sales Charge: 0 00
Redemption Fee: 0.00

12b-1 Fee: 0 00
Management Fee 0 50

Operations

Ticker Symbol· DFSCX

Morning Star Report on DFA 9-10 Fund

Fund Family:	DFA Investment Dimensions Group
Address:	1299 Ocean Avenue 11th Floor
	Santa Monica, CA 90401
Telephone:	310-395-8005
Fund Manager:	Management Team
Manager Tenure	NA years
Min. Initial Purchase	$2000000

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225 W. Wacker Dr. Chicago, IL 60606, 312-696-6000
Although data are gathered from reliable sources,
completeness and accuracy cannot be guaranteed

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DFA Investment Dimensions Group Inc.
and
The DFA Investment Trust Company

ANNUAL REPORT

Year Ended November 30, 1996

DFA INVESTMENT DIMENSIONS GROUP INC.

FINANCIAL HIGHLIGHTS

for a share outstanding throughout each year

	The U.S. 9-10 Small Company Portfolio									
	Year Ended Nov 30, 1996	Year Ended Nov. 30, 1995	Year Ended Nov. 30, 1994	Year Ended Nov. 30, 1993	Year Ended Nov 30, 1992	Year Ended Nov. 30, 1991	Year Ended Nov 30, 1990	Year Ended Nov 30, 1989	Year Ended Nov 30, 1988	Year Ended Nov 30, 1987
Net Asset Value Beginning of Period	$ 11 03	$ 8 49	$ 8 69	$ 7 75	$ 6 33	$ 5 34	$ 7 74	$ 7 66	$ 7 50	$ 8 94
Income From Investment Operations										
Net Investment Income	0 03	0 05	0 01	0 03	0 04	0 04	0 07	0 07	0 10	0 09
Net Gain (Losses) on Securities (Realized and Unrealized)	1 85	2 61	0 40	1 67	1 53	1 64	(1 77)	0 98	1 48	(1 53)
Total From Investment Operations	1 88	2 66	0 41	1 70	1 57	1 68	(1 70)	1 05	1 58	(1 44)
Less Distributions										
Net Investment Income	(0 01)	(0 04)	(0 03)	(0 05)	(0 05)	(0 07)	(0 08)	(0 09)	(0 11)	—
Net Realized Gains	(0 76)	(0 08)	(0 58)	(0 71)	(0 10)	(0 62)	(0 62)	(0 88)	(1 31)	—
Total Distributions	(0 77)	(0 12)	(0 61)	(0 76)	(0 15)	(0 69)	(0 70)	(0 97)	(1 42)	—
Net Asset Value, End of Period	$ 12 14	$ 11 03	$ 8 49	$ 8 69	$ 7 75	$ 6 33	$ 5 34	$ 7 74	$ 7 66	$ 7 50
Total Return	18 05%	31 37%	5 06%	23 91%	25 24%	39 08%	(24 09)%	16 09%	24 36%	(16 04)%
Net Assets End of Period (thousands)	$1,181,804	$925,474	$659 221	$630,918	$651,313	$722,289	$581,102	$949,291	$912,518	$788 821
Ratio of Expenses to Average Net Assets	0 61%	0 62%	0 65%	0 70%	0 68%	0 64%	0 62%	0 62%	0 62%	0 61%
Ratio of Net Investment Income to Average Net Assets	0 22%	0 45%	0 16%	0 26%	0 53%	0 75%	0 99%	0 86%	1 19%	0 92%
Portfolio Turnover Rate	23 68%	24 65%	16 56%	9 87%	9 72%	10 13%	3 79%	7 86%	25 98%	23 05%
Average Commission Rate (1)	$ 0 0604	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Computed by dividing the total amount of brokerage commissions paid by the total shares of investment securities purchased and sold during the period for which commissions were charged, as required by the SEC for fiscal years beginning after September 1, 1995

See accompanying Notes to Financial Statements

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Direct Testimony
Schedule 22
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Exhibit CA-SNB____
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Schedule 23_____
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DFA INVESTMENT DIMENSIONS GR(

1299 Ocean Avenue, 11th Floor, Santa Monica, California 90401
Telephone: (310) 395-8005

STATEMENT OF ADDITIONAL INFORMATION

March 28, 1997

DFA Investment Dimensions Group Inc. (the "Fund") offers thirty series of shares. This statement of additional information relates to twenty-four of those series (collectively, the "Portfolios"):

U.S. 9-10 Small Company Portfolio
U.S. 6-10 Small Company Portfolio
Enhanced U.S. Large Company Portfolio
U.S. Small Cap Value Portfolio
U.S. Large Cap Value Portfolio
DFA Real Estate Securities Portfolio
Japanese Small Company Portfolio
Pacific Rim Small Company Portfolio
United Kingdom Small Company Portfolio
Emerging Markets Portfolio
Emerging Markets Small Cap Portfolio
DFA Intermediate Government Fixed Income Portfolio
Continental Small Company Portfolio
Large Cap International Portfolio
U.S. Large Company Portfolio
DFA International Small Cap Value Portfolio
International Small Company Portfolio
DFA One-Year Fixed Income Portfolio
DFA Two-Year Corporate Fixed Income Portfolio
DFA Two-Year Global Fixed Income Portfolio
DFA Two-Year Government Portfolio
DFA Five-Year Government Portfolio
DFA Global Fixed Income Portfolio
RWB/DFA International High Book to Market Portfolio

This statement of additional information is not a prospectus but should be read in conjunction with the Portfolios' prospectus dated March 28, 1997, as amended from time to time, which can be obtained from the Fund by writing to the Fund at the above address or by calling the above telephone number.

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from the Series to satisfy the Portfolio's redemption request. Any such redemption t the Portfolio would be in accordance with Rule 18f-1 under the Investment Cor Investors may incur brokerage charges and other transaction costs selling securities t payment of redemptions. The International Equity, DFA Two-Year Global Fixed Inc... Global Fixed Income Portfolios reserve the right to redeem their shares in the currencies in which their investments (and, in respect of the Feeder Portfolios and International Small Company Portfolio, the currencies in which the corresponding Series' investments) are denominated. Investors may incur charges in converting such securities to dollars and the value of the securities may be affected by currency exchange fluctuations.

Shareholders may transfer shares of any Portfolio to another person by making a written request therefore to the Advisor who will transmit the request to the Fund's Transfer Agent. The request should clearly identify the account and number of shares to be transferred, and include the signature of all registered owners and all stock certificates, if any, which are subject to the transfer. The signature on the letter of request, the stock certificate or any stock power must be guaranteed in the same manner as described in the prospectus under "REDEMPTION OF SHARES." As with redemptions, the written request must be received in good order before any transfer can be made.

CALCULATION OF PERFORMANCE DATA

Following are quotations of the annualized percentage total returns for the one-, five-, and ten-year periods ended November 30, 1996 (as applicable) using the standardized method of calculation required by the SEC, which is net of the cost of any current reimbursement fees charged to investors and paid to the Portfolios. Also included is a quotation of the annualized percentage total return for the DFA Two-Year Global Fixed Income Portfolio (for the period from February 9, 1996, the date of commencement of operations), the Enhanced U.S. Large Company Portfolio (for the period from July 3, 1996, the date of commencement of operations) and the International Small Company Portfolio (for the period from October 1, 1996, the date of commencement of operations) to November 30, 1996 using the standardized method of calculation required by the SEC. Reimbursement fees of 1%, 1.5% and 1.5% were in effect from the inception of the Japanese, United Kingdom and Continental Small Company Portfolios, respectively, until June 30, 1995. A reimbursement fee of 1% was in effect from the inception of DFA International Small Cap Value Portfolio until June 30, 1995. Effective June 30, 1995, the amount of the reimbursement fee was reduced with respect to Continental Small Company, Pacific Rim Small Company, Japanese Small Company, Emerging Markets and DFA International Small Cap Value Portfolios, and eliminated with respect to the United Kingdom Small Company Portfolio. The current reimbursement fee for each Portfolio, expressed as a percentage of the net asset value of the shares of the Portfolios, is as follows: Continental Small Company, Pacific Rim Small Company and Emerging Markets Small Cap Portfolios - 1.00%; Japanese Small Company and Emerging Markets Portfolios - .50%; DFA International Small Cap Value Portfolio - .70%; and International Small Company Portfolio - .70%.

A reimbursement fee of 1% was charged to investors in The U.S. 9-10 Small Company Portfolio from December 9, 1986 through June 17, 1988. A reimbursement fee of 0.75% was charged to investors in The Large Cap International Portfolio from the date of its inception until March 5, 1992. In addition, for those Portfolios in effect for less than one, five, or ten years, the time periods during which the Portfolios have been active have been substituted for the periods stated (which in no case extends prior to the effective dates of the Portfolios' registration statements).

	One Year	Five Years	Ten Years
U.S. 9-10 Small Company Portfolio	18.03	20.38	12.35
U.S. 6-10 Small Company Portfolio	18.73	57 Months 13.42	n/a
U.S. Large Company Portfolio	27.48	17.88	71 Months 17.97

U.S. Small Cap Value Portfolio	21.77		
U.S. Large Cap Value Portfolio	22.26	46 Months 16.04	n/a
Enhanced U.S. Large Company Portfolio	4 Months 73.24	n/a	n/a
DFA Real Estate Securities Portfolio	28.24	47 Months 9.63	n/a
Japanese Small Company Portfolio	-6.74	-1.07	8.58
Pacific Rim Small Company Portfolio	17.87	47 Months 18.01	n/a
United Kingdom Small Company Portfolio	26.74	10.30	10.73
Emerging Markets Portfolio	12.61	31 Months 5.89	n/a
Continental Small Company Portfolio	12.83	5.39	103.5 Months 8.31
Large Cap International Portfolio	12.68	64 Months 8.27	n/a
RWB/DFA International High Book to Market Portfolio	14.60	42 Months 10.62	n/a
DFA One-Year Fixed Income Portfolio	5.91	5.28	6.70
DFA Five-Year Government Portfolio	7.54	6.25	114 Months 7.79
DFA Global Fixed Income Portfolio	11.13	8.40	72 Months 8.83
DFA Intermediate Government Fixed Income Portfolio	4.98	7.89	73 Months 9.37
DFA International Small Cap Value Portfolio	7.24	23 Months 2.08	n/a
DFA Two-Year Global Fixed Income Portfolio	10 Months 7.14	n/a	n/a
International Small Company Portfolio	2 Months -0.40	n/a	n/a

As the following formula indicates, the average annual total return is determined by finding the average annual compounded rates of return over the stated time period that would equate a hypothetical initial purchase order of $1,000 to its redeemable value (including capital appreciation/depreciation and dividends and distributions paid and reinvested less any fees charged to a shareholder account) at the end

of the stated time period. The calculation assumes that all dividends and distributions are reinvested at the public offering price on the reinvestment dates during the period. The quotation assumes the account was completely redeemed at the end of each period and the deduction of all applicable charges and fees. According to the SEC formula:

$$P(1 + T)^n = ERV$$

where:

P = a hypothetical initial payment of $1,000

T = average annual total return

n = number of years

ERV = ending redeemable value of a hypothetical $1,000 payment made at the beginning of the one-, five-, and ten-year periods at the end of the one-, five-, and ten-year periods (or fractional portion thereof).

Following are quotations of the annualized total returns for the one-, five-, and ten-year periods ended November 30, 1996 (as applicable) using a non-standardized method of calculation which is used in communicating performance data in addition to the standardized method required by the SEC. Also included is a quotation of the annualized percentage total return for the DFA Two-Year Global Fixed Income Portfolio (for the period from February 9, 1996, the date of commencement of operations), the Enhanced U.S. Large Company Portfolio (for the period from July 3, 1996, the date of commencement of operations) and the International Small Company Portfolio (for the period from October 1, 1996, the date of commencement of operations) to November 30, 1996 using a non-standardized method of calculation. The non-standardized quotations differ from the standardized in that they are calculated without deduction of any reimbursement fees charged to investors and paid to the Portfolios which would otherwise reduce return quotations for the Portfolios with such fees. Additionally, the non-standardized quotations are presented over time periods which extend prior to the initial investment in the Portfolios (except for The Continental Small Company (and Large Cap International) Portfolios) by using simulated data for the investment strategies of the Portfolios for that portion of the period prior to the initial investment dates. The simulated data excludes the deduction of Portfolio expenses which would otherwise reduce the returns quotations. Non-standardized quotations are also presented for the United Kingdom and Japanese Small Company Portfolios calculated assuming the local currencies of the corresponding Series are invested and redeemed at the beginning and ending dates of the period. The local currency calculations ignore the effect of foreign exchange rates on the investment and only express the returns of the underlying securities of the Series.

	Effective Date/ Initial Investment	One Year	Five Years	Ten Years
U.S. 9-10 Small Company Portfolio	12/22/81 12/22/81	18.03	20.38	12.46
U.S. 6-10 Small Company Portfolio	03/06/92 03/20/92	18.73	17.00	11.57
U.S. Large Company Portfolio	02/26/90 12/31/90	27.48	17.88	15.02
U.S. Small Cap Value Portfolio	09/18/92 03/01/93	21.77	22.14	14.88
U.S. Large Cap Value Portfolio	09/18/92 02/18/93	22.26	20.47	15.32

...ures and forward contracts is generally governed by Section 1256 of the Code. ...positions generally include listed options on debt securities, options on broad-based ...on futures contracts, regulated futures contracts and certain foreign currency contracts and options thereon.

Absent a tax election to the contrary, each such Section 1256 position held by a Portfolio or Series will be marked-to-market (i.e., treated as if it were sold for fair market value) on the last business day of a Portfolio's or Series' fiscal year, and all gain or loss associated with fiscal year transactions and marked-to-market positions at fiscal year end (except certain currency gain or loss covered by Section 988 of the Code) will generally be treated as 60% long-term capital gain or loss and 40% short-term capital gain or loss. The effect of Section 1256 marked-to-market rules may be to accelerate income or to convert what otherwise would have been long-term capital gains into short-term capital gains or short-term capital losses into long-term capital losses within a Portfolio or Series. The acceleration of income on Section 1256 positions may require a Portfolio or Series to accrue taxable income without the corresponding receipt of cash. In order to generate cash to satisfy the distribution requirements of the Code, a Portfolio or Series may be required to dispose of portfolio securities that it otherwise would have continued to hold or to use cash flows from other sources such as the sale of a Portfolio's or Series' shares. In these ways, any or all of these rules may affect both the amount, character and timing of income distributed to shareholders by a Portfolio.

When a Portfolio (or in the case of a Feeder Portfolio, the corresponding Series) holds an option or contract which substantially diminishes a Portfolio's or Series' risk of loss with respect to another position of a Portfolio or Series (as might occur in some hedging transactions), this combination of positions could be treated as a "straddle" for tax purposes, resulting in possible deferral of losses, adjustments in the holding periods of a Portfolio's or Series' securities and conversion of short-term capital losses into long-term capital losses. Certain tax elections exist for mixed straddles (i.e., straddles comprised of at least one Section 1256 position and at least one non-Section 1256 position) which may reduce or eliminate the operation of these straddle rules.

The Portfolios and those Series taxable as regulated investment companies are also subject to the requirement that less than 30% of their annual gross income be derived from the sale or other disposition of securities and certain other investments held for less than three months ("short-short income"). This requirement may limit a Portfolio's (or in the case of a Feeder Portfolio, the corresponding Series') ability to engage in options, straddles, hedging transactions and forward or futures contracts because these transactions are often consummated in less than three months, may require the sale of portfolio securities held less than three months and may, as in the case of short sales of portfolio securities, reduce the holding periods of certain securities within a Portfolio or Series, resulting in additional short-short income for a Portfolio or Series.

A Portfolio (or in the case of a Feeder Portfolio, the corresponding Series) will monitor its transactions in such options and contracts and may make certain other tax elections in order to mitigate the effect of the above rules and to prevent disqualification of a Portfolio or Series as a regulated investment company under Subchapter M of the Code.

DIRECTORS AND OFFICERS

The names and addresses of the directors and officers of the Fund and a brief statement of their present positions and principal occupations during the past five years is set forth below.

Directors

David G. Booth*, 50, Director, President and Chairman-Chief Executive Officer, Santa Monica, CA. President, Chairman-Chief Executive Officer and Director, Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc. (registered investment company) and Dimensional Emerging Markets Fund Inc. (registered investment company). Trustee, President and Chairman-Chief Executive Officer of The DFA Investment Trust Company. Chairman and Director, Dimensional Fund Advisors Ltd.

George M. Constantinides, 49, Director, Chicago, IL. L Graduate School of Business, University of Chicago. Trustee, Th Director, Dimensional Investment Group Inc. and Dimensional Emt

John P. Gould, 58, Director, Chicago, IL. Steven G. Rothmeier Distinguished Service Professor of Economics, Graduate School of Business, University of Chicago. Trustee, The DFA Investment Trust Company and First Prairie Funds (registered investment companies). Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc. and Harbor Investment Advisors. Executive Vice President, Lexecon Inc. (economics, law, strategy and finance consulting).

Roger G. Ibbotson, 53, Director, New Haven, CT. Professor in Practice of Finance, Yale School of Management. Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc., Hospital Fund, Inc. (investment management services) and BIRR Portfolio Analysis, Inc. (software products). Chairman and President, Ibbotson Associates, Inc., Chicago, IL (software, data, publishing and consulting).

Merton H. Miller, 73, Director, Chicago, IL. Robert R. McCormick Distinguished Service Professor Emeritus, Graduate School of Business, University of Chicago. Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc. and Dimensional Emerging Markets Fund Inc. Public Director, Chicago Mercantile Exchange.

Myron S. Scholes, 55, Director, Greenwich, CT. Limited Partner, Long-Term Capital Management L.P. (money manager). Frank E. Buck Professor of Finance, Graduate School of Business and Professor of Law, Law School, Senior Research Fellow, Hoover Institution, (all) Stanford University (on leave). Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc., Benham Capital Management Group of Investment Companies and Smith Breedon Group of Investment Companies.

Rex A. Sinquefield*, 52, Director, Chairman and Chief Investment Officer, Santa Monica, CA. Chairman-Chief Investment Officer and Director, Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc. and Dimensional Emerging Markets Fund Inc. Trustee, Chairman-Chief Investment Officer of The DFA Investment Trust Company. Chairman, Chief Executive Officer and Director, Dimensional Fund Advisors Ltd.

* Interested Director of the Fund.

Officers

Each of the officers listed below hold the same office in the following entities: Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc., The DFA Investment Trust Company, Dimensional Fund Advisors Ltd., and Dimensional Emerging Markets Fund Inc.

Arthur Barlow, 41, Vice President, Santa Monica, CA.

Maureen Connors, 60, Vice President, Santa Monica, CA.

Truman Clark, 55, Vice President, Santa Monica, CA. Consultant until October 1995 and Principal and Manager of Product Development, Wells Fargo Nikko Investment Advisors, San Francisco, CA from 1990-1994.

Robert Deere, 39, Vice President, Santa Monica, CA.

Irene R. Diamant, 46, Vice President and Secretary (for all entities other than Dimensional Fund Advisors Ltd.), Santa Monica, CA.

Margaret East, 56, Secretary, Dimensional Fund Advisors Ltd.

The Fund commenced offering shares of Emerging Mark International Small Cap Value Portfolio in December, 1994; DFA Two- in February, 1996; Enhanced U.S. Large Company Portfolio in July, 199[illegible] International Small Company Portfolio in October, 1996. The DFA Two-Year Corporate Fixed Income, DFA Two-Year Government and Emerging Markets Small Cap Portfolios had not commenced operations as of November 30, 1996.

Until September, 1995, The DFA Intermediate Government Fixed Income Portfolio was named The DFA Intermediate Government Bond Portfolio, The DFA Global Fixed Income Portfolio was named The DFA Global Bond Portfolio, The Pacific Rim Small Company Portfolio was named The Asia-Australia Small Company Portfolio, The U.S. Large Cap Value Portfolio was named The U.S. Large Cap High Book to Market Portfolio, The U.S. Small Cap Value Portfolio was named The U.S. Small Cap High Book to Market Portfolio, The U.S. 9-10 Small Company Portfolio was named the Small Company Shares, The DFA One-Year Fixed Income Portfolio was named The DFA Fixed Income Shares, and The Continental Small Company Portfolio was named the Continental European Portfolio. Until February, 1996, RWB/DFA International High Book to Market Portfolio was named DFA International High Book to Market Portfolio. From September, 1995 until December, 1996, The DFA Real Estate Securities Portfolio was named DFA/AEW Real Estate Securities Portfolio.

Coopers and Lybrand L.L.P., the Fund's independent accountants, audits the Fund's financial statements.

PRINCIPAL HOLDERS OF SECURITIES

As of February 28, 1997, the following stockholders owned beneficially at least 5% of the outstanding stock of the Portfolios, as set forth below.

THE U.S. 9-10 SMALL COMPANY PORTFOLIO

Charles Schwab & Company, Inc. - REIN* 101 Montgomery Street San Francisco, CA 94104		25.44%
State Farm Insurance Companies One State Farm Plaza Bloomington, IL 61710		10.76%
Pepsico Inc. Master Trust The Northern Trust Company Trustee P.O. Box 92956 801 South Canal Chicago, IL 60675		8.87%
Charles Schwab & Company, Inc. - REIN*	(see address above)	5.97%
Owens-Illinois Master Retirement Trust 34 Exchange Place Jersey City, NJ 07302		5.48%
National Electrical Benefit Fund 1125 15th Street NW Washington, DC 20005		5.26%

THE U.S. 6-10 SMALL COMPANY PORTFOLIO

McKinsey & Company Master Retiremen[illegible] Trust 55 E. 52nd Street New York, NY 10055		26.43%

Data on Dr. Andrews' Companies

Docket No 97-00982
Exhibit CA-SNB___
Direct Testimony___
Schedule 25 _____
Page 1 of 1_____

COMPANY NAME *	PRICE AS OF 4/30/97	STOCK OUTSTANDING (000)	NUM OF SHARE HOLDERS	SHARES PER STOCKHOLDER	VALUE OF HOLDINGS PER SHAREHOLDER 4/30/97	MARKET VALUE 4/30/97 $(Millions)
(1)	(2)	(3)	(4)	(5) [col (3) / col (4)]	(6) [col (2) X col (5)]	(7) [col (2) X col (3)]
Atmos Energy Corporation	$22 63	16135	28,624	564	$12,753	365
Berkshire Gas Company	$15 13	2177	1,881	1157	$17,505	33
Bay State Gas Company	$25 50	13439	10,820	1242	$31,671	343
Cascade Natural Gas Corporation	$16 38	10824	10840	999	$16,351	177
Colonial Gas Company	$20 00	8518	5931	1436	$28,724	170
Chesapeake Utilities Corporation	$16 75	4453	2213	2012	$33,704	75
Delta Natural Gas Company, Inc	$16 63	2325	2,382	976	$16,227	39
Essex County Gas Company	$24 25	1667	1,336	1248	$30,258	40
Energen Corporation	$30 50	13027	7,700	1692	$51,600	397
Energy North Inc	$21 75	3244	2,300	1410	$30,677	71
Energy West Incorporated	$8 50	2357	1,600	1473	$12,522	20
Mobile Gas Service Corporation	$26 75	3228	1,624	1988	$53,171	86
North Carolina Natural Gas Corporation	$29 63	6613	5,094	1298	$38,459	196
Northwest Natural Gas Company	$24 25	22566	10,859	2078	$50,394	547
Public Service Company of North Carolina, Incorporated	$17 25	19296	11,500	1678	$28,945	333
Pennsylvania Enterprises, Inc	$22 13	9608	6,627	1450	$32,077	213
Providence Energy Corporation	$17 75	5767	6,052	953	$16,914	102
Southeastern Michigan Gas Enterprises, Inc	$17 58	13020	8,509	1530	$26,892	229
United Cities Gas Company	$21 50	13221	7681	1721	$37,007	284
Valley Resources, Inc	$12 25	4266	2824	1511	$18,505	52
Yankee Energy System, Inc	$21 13	10450	28,499	367	$7,746	221
Average	$20 39	8867	7,852	1371	$28,195	190

* Excludes Washington Gas Company
It Merged With an Electric Power Company

Gas Company Stocks Owned by the DFA 9-10 Fund

Did the U S 9-10 Small Company Mutual Fund Own Stock in Dr Andrews' Comparable Companies?

COMPANY	YEAR 94	95	96
Atmos Energy Corporation	NO	NO	NO
Berkshire Gas Company	YES	YES	YES
Bay State Gas Company	NO	NO	NO
Cascade Natural Gas Corporation	YES	YES	YES
Chesapeake Utilities Corporation	YES	YES	YES
Colonial Gas Company	YES	YES	YES
Delta Natural Gas Company, Inc.	YES	YES	YES
Energen Corporation	NO	NO	NO
Energy North Inc	YES	NO	YES
Energy West Incorporated	NO	NO	NO
Essex County Gas Company	NO	YES	YES
Mobile Gas Service Corporation	YES	YES	YES
North Carolina Natural Gas Corporation	NO	NO	YES
Northwest Natural Gas Company	NO	NO	NO
Pennsylvania Enterprises, Inc.	NO	NO	NO
Providence Energy Corporation	YES	YES	YES
Public Service Company of North Carolina, Incorporated	NO	NO	NO
Southeastern Michigan Gas Enterprises, Inc	NO	NO	NO
United Cities Gas Company	NO	NO	NO
Washington Energy	NO	NO	NO
Valley Resources, Inc.	YES	YES	YES
Yankee Energy System, Inc.	NO	NO	NO
TOTAL *NOT* INCLUDED IN PORTFOLIO	13	13	11
TOTAL INCLUDED IN PORTFOLIO	9	9	11

SOURCE 1994 & 1996 - DFA ANNUAL REPORT
SOURCE 1995 1OK REPORT

Table A-1 Large Company Stocks: Total Returns

(continued)

Docket No. 97-00982
Exhibit CA-SNB____
Direct Testimony___
Schedule 27_____
Page 1 of 1____

From January 1971 to December 1995

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR	JAN-DEC*
1971	0 0419	0 0141	0 0382	0 0377	-0 0367	0 0021	-0 0399	0 0412	-0 0056	-0 0404	0 0027	0 0877	1971	0 1431
1972	0 0194	0 0299	0 0072	0 0057	0 0219	-0 0205	0 0036	0 0391	-0 0036	0 0107	0 0505	0 0131	1972	0 1898
1973	-0 0159	-0 0333	-0 0002	-0 0395	-0 0139	-0 0051	0 0394	-0 0318	0 0415	0 0003	-0 1082	0 0183	1973	-0 1466
1974	-0.0085	0 0019	-0.0217	-0 0373	-0 0272	-0 0128	-0 0759	-0 0828	-0 1170	0 1657	-0 0448	-0 0177	1974	-0.2647
1975	0.1251	0 0674	0 0237	0 0493	0 0509	0 0462	-0 0659	-0 0144	-0 0328	0 0637	0 0313	-0 0096	1975	0 3720
1976	0 1199	-0 0058	0 0326	-0 0099	-0 0073	0 0427	-0 0068	0 0014	0 0247	-0 0206	-0 0009	0 0540	1976	0.2384
1977	-0 0489	-0 0151	-0 0119	0 0014	-0 0150	0 0475	-0 0151	-0 0133	0 0000	-0 0415	0 0370	0 0048	1977	-0 0718
1978	-0 0596	-0 0161	0.0276	0 0870	0 0136	-0 0152	0 0560	0 0340	-0 0048	-0 0891	0 0260	0 0172	1978	0.0656
1979	0 0421	-0 0284	0 0575	0 0036	-0 0168	0 0410	0 0110	0 0611	0 0025	-0 0656	0 0514	0 0192	1979	0 1844
1980	0 0610	0 0031	-0 0987	0 0429	0 0562	0.0296	0 0676	0 0131	0 0281	0 0187	0 1095	-0 0315	1980	0.3242
1981	-0 0438	0 0208	0 0380	-0 0213	0 0062	-0 0080	0 0007	-0 0554	-0 0502	0 0528	0 0441	-0 0265	1981	-0 0491
1982	-0 0163	-0 0512	-0 0060	0 0414	-0 0288	-0 0174	-0 0215	0 1267	0 0110	0 1126	0 0438	0 0173	1982	0 2141
1983	0 0348	0 0260	0 0365	0 0758	-0 0052	0 0382	-0 0313	0 0170	0 0136	-0 0134	0 0233	-0 0061	1983	0.2251
1984	-0 0065	-0 0328	0 0171	0 0069	-0 0534	0 0221	-0 0143	0 1125	0 0002	0 0026	-0.0101	0.0253	1984	0 0627
1985	0 0768	0 0137	0 0018	-0 0032	0 0615	0 0159	-0 0026	-0 0061	-0 0321	0 0447	0 0716	0 0467	1985	0 3216
1986	0 0044	0 0761	0 0554	-0 0124	0 0549	0 0166	-0 0569	0 0748	-0 0822	0 0556	0 0256	-0 0264	1986	0 1847
1987	0 1343	0 0413	0 0272	-0 0088	0 0103	0 0499	0 0498	0 0385	-0 0220	-0 2152	-0 0819	0 0738	1987	0 0523
1988	0 0427	0 0470	-0 0302	0 0108	0 0078	0.0464	-0 0040	-0 0331	0 0424	0 0273	-0 0142	0.0181	1988	0 1681
1989	0 0723	-0 0249	0 0236	0 0516	0 0402	-0 0054	0 0898	0 0193	-0 0039	-0 0233	0 0208	0 0236	1989	0 3149
1990	-0 0671	0 0129	0 0263	-0 0247	0 0975	-0 0070	-0 0032	-0 0903	-0 0492	-0 0037	0 0644	0.0274	1990	-0 0317
1991	0 0442	0 0716	0 0238	0 0028	0 0428	-0 0457	0 0468	0 0235	-0 0164	0 0134	-0 0404	0 1143	1991	0 3055
1992	-0.0186	0 0128	-0 0196	0 0291	0 0054	-0 0145	0 0403	-0 0202	0 0115	0 0036	0 0337	0 0131	1992	0 0767
1993	0 0073	0 0135	0 0215	-0 0245	0 0270	0 0033	-0 0047	0 0381	-0 0074	0 0203	-0 0094	0 0123	1993	0 0999
1994	0 0335	-0 0270	-0 0435	0 0130	0 0163	-0 0247	0 0331	0 0407	-0 0241	0 0229	-0 0367	0 0146	1994	0 0131
1995	0 0260	0 0388	0 0296	0 0291	0 0395	0 0235	0 0333	0 0027	0 0419	-0 0035	0 0440	0 0185	1995	0 3743

* Compound annual return

Office of the Consumer Advocate Interrogatory/Data Request-7/8/97

Q.47. Regarding the results of Dr. Andrew's regression analysis shown in Schedule 9, produce the T-statistic for each company's alpha and the T-statistic for each company's beta.

A.47. The results of regressions performed on the data for each company listed in Schedule 9 are employed only in summary, aggregated form as average alphas and betas. The average alpha and average beta are analogous to the alpha and beta of a portfolio of common stocks, in this case a "portfolio" of 22 small gas LDC's. Tests of significance, such as T-statistics, from the regressions related to individual stocks intrinsically cannot be summed or averaged across the composite (or portfolio). Accordingly, they were not found in company with the individual regressions and, hence, cannot be supplied as requested.

Victor L. Andrews

Signature

Victor L. Andrews, President, Andrews Financial Associates, Inc.

APPENDIX A

IBBOTSON YEARBOOK'S HYPOTHETICAL DISTRIBUTION OF RETURNS

The derivation of Schedule 12 and Charts two and three is based on the same probability principles used in the example shown in SBBI-97 at pages 154-155. Those pages are attached to and are part of this appendix as Attachments 1 and 2. The hypothetical distribution in the example assumes:

10% is the size of the loss

30% is the size of the gain

50% is the probability of a loss

50% is the probability of a gain.

Starting with an investment of $1, after 1 year there are two possible values, the investment will be worth either $1.3 or 90 cents. After two years there are 4 possibilities, one at $1.69, two outcomes at $1.17 and one at $.81. This shows that the number of possibilities double each year. The example is well-grounded in mathematics and is a simple illustration of a mathematical formula that is over 500 years old. If $1.3 is treated as X and $.9 is treated as Y, the first year after the investment the possible outcomes are:

$$(X + Y)^1 = \underline{1}(\$1.3) + \underline{1}(\$.9)$$

In the second year after the investment the possible outcomes are:

$$(X + Y)^2 = \underline{1}(X^2) + \underline{2}(XY) + \underline{1}(Y^2)$$

$$(\$1.3 + \$.9)^2 = \underline{1}(\$1.69) + \underline{2}(\$1.17) + \underline{1}(\$.81)$$

The underlined values -- 1 and 1 in the first year and 1, 2 ,1 in the second year -- match the total number of possibilities - 2 in the first year and 4 in the second, and the values in the parentheses -- $1.3 and $.9 in the first year and $1.69 ,$1.17, $.81 in the second -- represent the values of the possibilities. There are two important aspects of the example especially in the second year: the geometric mean is the middle value, $1.17, which has a corresponding annual return of 8.2%, is the most likely outcome - 2 chances out of four. Three out of the four chances, 75% of the possibilities, are at or below the middle value. The odds are only 25% that the investment will reach the average of $1.21, which has a corresponding return of 10%.

The heart of the example can be restated.

This information about a distribution:

10% is the size of the loss

30% is the size of the gain

50% is the probability of a loss

50% is the probability of a gain.

Leads to these facts about the distribution:

an 8.2% return is the distribution's middle

a 10% return is the distribution's average

And

the number of possibilities doubles as the years increase: in the first year there are 2

possibilities, 4 in the second, 8 in the third and so forth.

By the time 71 years elapse from 1925 to 1996 the equation above changes to:

$$(X + Y)^{71}$$

Although this term is huge it can be calculated easily with computers, giving the total number of possibilities and the possibilities for each outcome. Attachments 3 and 4 show the possibilities each year, the symmetrical pattern each year and the distribution in percentage terms. The patterns do not depend on the values of X and Y. No matter what values X and Y are, the pattern of possibilities is the same. This is why Chart 3 in my direct testimony is also symmetrical.

ACTUAL DISTRIBUTION OF LARGE COMPANY RETURNS: 1925-1996

Ibbotson's data on large companies covers 71 years. It shows a return of 10.7% as being in the middle of the distribution and an average of return of 12.7%. This is different than the example in the sense that the order of the information is reversed from the example.

The information about the actual distribution:

a 10.7% return is the distribution's middle

a 12.7% return is the distribution's average

50% is the probability of a loss

50% is the probability of a gain.

Leads to these questions about the actual distribution:

What percentage is the size of the loss?

What percentage is the size of the gain?

I calculated the size of the loss to be 8.3% and the size of the gain to be 33.6%. These are the first and last values in column (3) of Schedule 12. I then applied these two figures to the formula

$$(X + Y)^{71}$$

This gives the total number of possible returns, the value of each return ,and the probability of each return in 1996 - given a $1 investment in 1925. This is the data shown in Schedule 12.

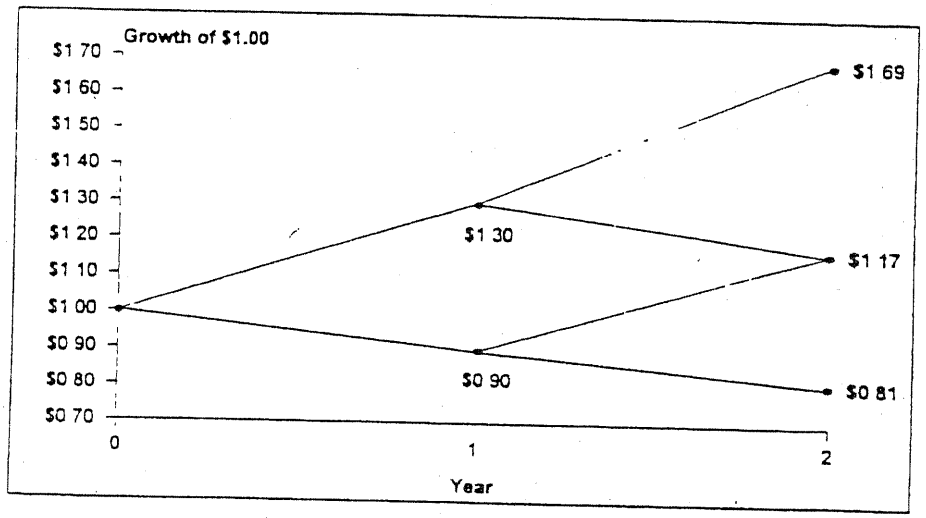
The Schedule indicates that the average return, 12.7%, has a less then 20% chance of being achieved in 1996. If the odds were looked at in 1927, the second year after the investment, the chance of achieving the average return would be no more than 25%. The point here is that as time progresses, the average return has a little less of a chance of being achieved. Its odds shrink from no more than 25% in the second year to less than 20% in the 71st year. This is not much of a change, but it highlights why the average return is not considered a useful measure by the sources I quoted. The average return is not the midpoint of the distribution, and the average return gets further and further away from the midpoint as time progresses.

where the cost of capital is the sum of its parts Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.

Arithmetic Versus Geometric Means

The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. (A simple example given below shows that this is true.) This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their expected (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will, therefore, require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment.

For example, assume a stock has an expected return of +10 percent in each year and a standard deviation of 20 percent. Assume further that only two outcomes are possible each year— + 30 percent and -10 percent (that is, the mean plus or minus one standard deviation), and that these outcomes are equally likely. (The arithmetic mean of these returns is 10 percent, and the geometric mean is 8.2 percent.) Then the growth of wealth over a two-year period occurs as shown below.



Appendix A of ____
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Attachment 2

Note that the median (middle outcome) and mode (most common outcome) are given by the geometric mean, 8.2 percent, which compounds up to 17 percent over a 2-year period (hence a terminal wealth of $1.17). However, the *expected value*, or probability-weighted average of all possible outcomes, is equal to:

	(.25	×	1.69)	=	0.4225
+	(.50	×	1.17)	=	0.5850
+	(.25	×	0.81)	=	0.2025
TOTAL					1.2100

Now, the rate that must be compounded up to achieve a terminal wealth of $1.21 after 2 years is 10 percent; that is, the expected value of the terminal wealth is given by compounding up the *arithmetic*, not the geometric mean. Since the arithmetic mean equates the expected future value with the present value, it is the discount rate.

Stated another way, the arithmetic mean is correct because an investment with uncertain returns will have a higher expected ending wealth value than an investment that earns, with certainty, its compound or geometric rate of return every year. In the above example, compounding at the rate of 8.2 percent for two years yields a terminal wealth of $1.17, based on $1.00 invested. But holding the uncertain investment, with a possibility of high returns (two +30 percent years in a row) as well as low returns (two -10 percent years in a row), yields a higher expected terminal wealth, $1.21. In other words, more money is gained by higher-than-expected returns than is lost by lower-than-expected returns. Therefore, in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

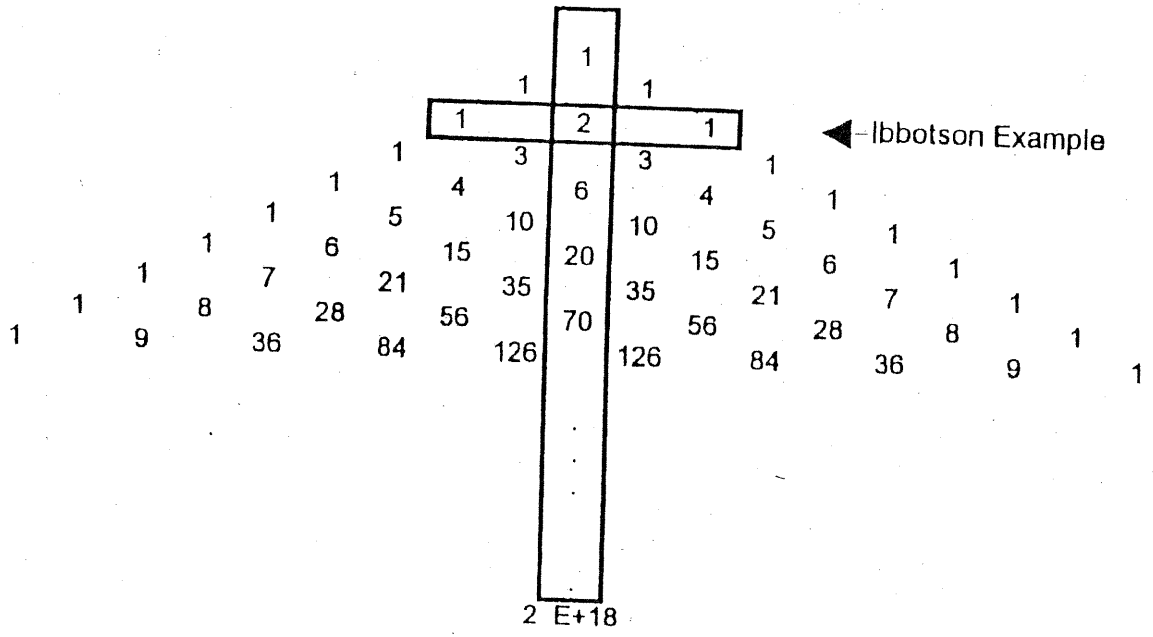
Arbitrage Pricing Theory

APT is a model of the expected return on a security. It was originated by Stephen A. Ross, and elaborated by Richard Roll. APT treats the expected return on a security (*i.e.*, its cost of capital) as the sum of the payoffs for an indeterminate number of risk factors, where the amount of each risk factor inherent in a given security is estimated. Like the CAPM, APT is a model that is consistent with equilibrium and does not attempt to outguess the market. APT

Appendix A of _____
Direct Testimony
Docket No. 97-00982
Exhibit CA-SNB____
Attachment 3

Distribution of Possibilities for (X + Y)

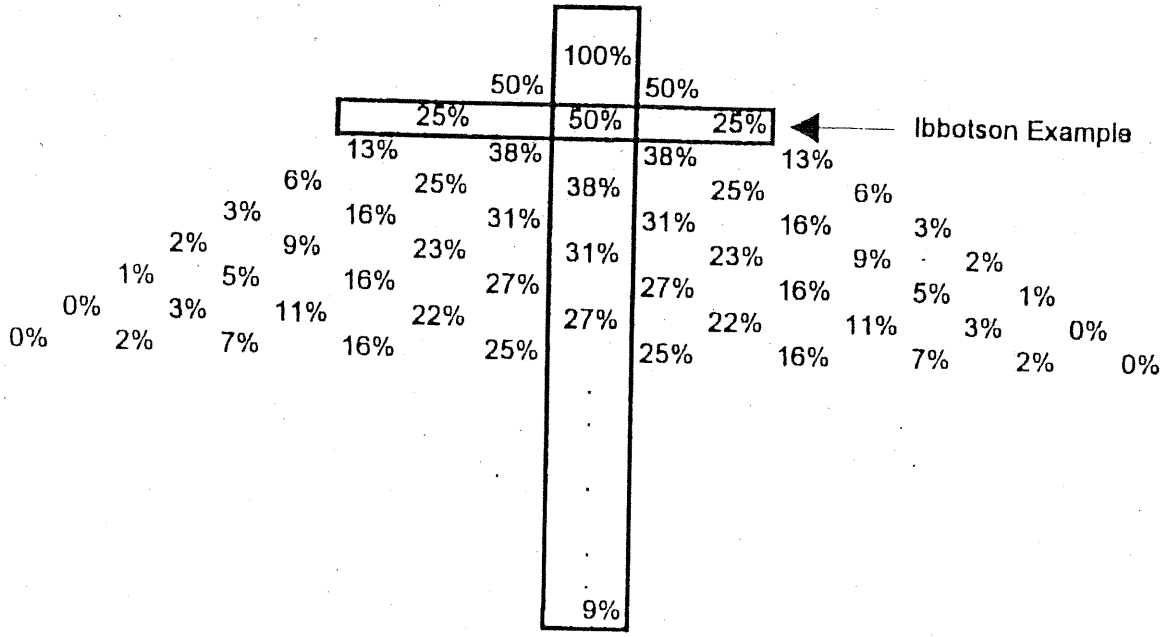
Center of the Distribution



Total Possibilities Each Year	Year
2	0
4	1
8	2
16	3
32	4
64	5
128	6
256	7
512	8
2 E+21	71

Appendix A of _____
Direct Testimony
Docket No 97-00982
Exhibit CA-SNB____
Attachment 4

Distribution of Possibilities for (X + Y)
As a Percent of Possibilities
Center of the Distribution



Ibbotson Example

Total Possibilities Each Year	Year
1	0
4	1
8	2
16	3
32	4
64	5
128	6
256	7
512	8
.	9
.	.
.	.
2. E+21	71

Publications By Dr. Brown

(Copies Attached)

So Long, Calvin Coolidge

Meter Reading Approaches the 1990s Promising a Pivotal Market for Communications Infrastructure

By Stephen N. Brown

Federal and state regulators must become knowledgeable about Automatic Meter Reading (AMR) and all that it entails. After all, AMR is a pivotal market that will shape the nation's communications infrastructure by determining whether energy and water industries move toward an intelligent, public-switched communication network or toward radio-based personalized communication networks.

The junction lies in the eventual replacement of roughly 250 million electric, gas, and water meters in the United States, nearly all of which reflect the technology of the 1920s: they must be read manually, they are incapable of implementing time-differentiated rates, they cannot communicate with anything, and their information storage capability is nil. They will be replaced by devices embodying today's technology, and that will be compatible with the nation's communication infrastructure.

Radio Networks or Wired Networks?

The infrastructure is being shaped by the century-old competition between radio networks and wired networks. Radio-based cellular and microwave technology use the electromagnetic spectrum and offer the promise of personalized communication networks (PCNs) along with decentralized ownership and splintered control of the nation's communication infrastructure.

The AMR market already reflects the struggle over market position and the dichotomies between radio and wired technologies, and between unilateral control and integrated control. AMR products available today encompass various radio offerings, including one combination of spread-spectrum signalling with a power line carrier, as well as telephone-inbound/outbound strategies.Telephone-based products require cooperation between the local exchange carriers and the utility; the spread-spectrum/power-line device is unilaterally operated by the utility. However, there is no dominant AMR strategy or product in the electric, gas, and water industries; also, they have no organized strategy on how to migrate from a 1920's-vintage metering technology to the 1990s. The AMR market today is still immature, disorganized, and untapped, but loaded with potential.

Why?

Because replacing 250 million meters, not to mention possible markets abroad, represents a major demand for new manufactured products that embody new communication technology.

Capable Networks for Energy Industries

More capable networks are needed by the electric utility industry, which is under intense pressure to adopt energy efficiency strategies requiring load monitoring, load management, incentive rates, and perhaps eventually real-time pricing.AMR is essential for all these strategies. Therefore, regulators should advocate AMR investments in energy-utility networks, whether radio or cable-based, that:

- have scale economies;
- possess multi-functionality;
- can easily implement rate structure changes;
- are consistent with open-architecture principles;
- avoid redundancy and duplication of another local utility's investments.

The regulatory community should take the lead in advocating economic cooperation between different utility industries—not only for the potential economic benefits but also because the utilities and American business in general do not value economic cooperation.

Shorter Replacement Cycles

The application to AMR and the regulatory process is this: Regulated industries should be responsive to continual product improvements in AMR. Regulators should not expect AMR products to have a 30- to 40-year depreciation schedule, nor should they expect utilities to make automation investments and then not replace them for decades. Product replacements are likely to occur in shorter cycles such as eight to twelve years.This is true for either radio or wired technologies.

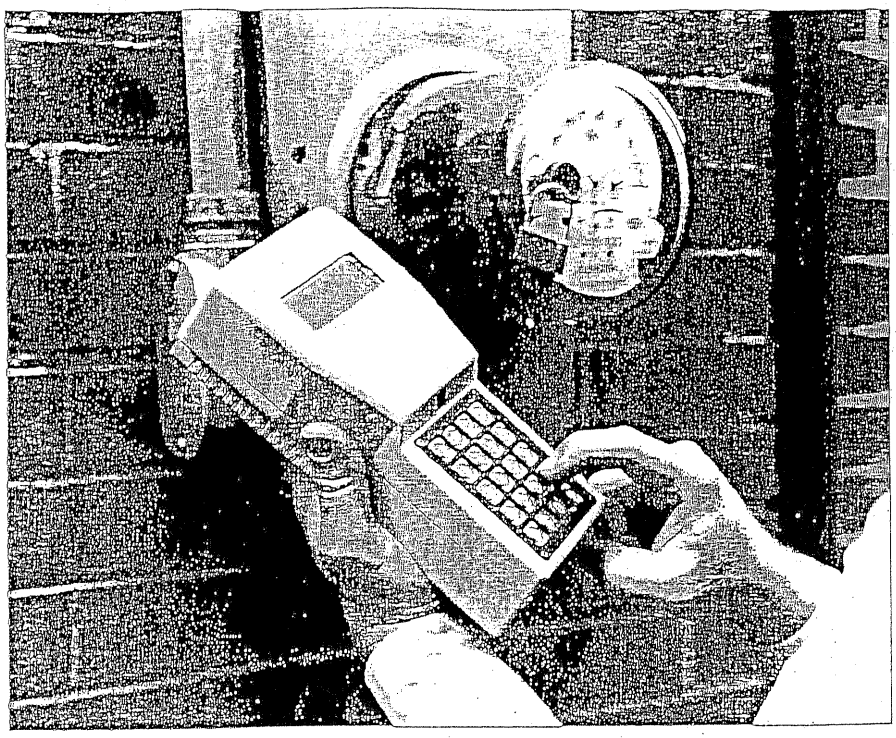
An important feature of continual product improvement is the role of customer feedback in guiding incremental improvements to the product after it has been introduced. This sug-

gests a need for continual cooperation between utilities and AMR manufacturers. In an intelligent network, product improvement means software improvements to create and access data bases that are centralized with regard to a local access transport area (LATA). Without an intelligent network, data bases are located in each local exchange. There are approximately 120-150 LATAs in the country along with several thousand local exchanges. Centralizing data bases in LATAs rather than local exchanges reduces the development cycle for new services from years to months.

However, the communications industry has no plans to develop processing capability in digital central office switches.An intelligent network offering speed but lacking distributed processing may have little value to electric utilities. Their long-term planning is evolving toward the distributed utility concept: the electrical distribution system becomes the focus of planning, processing, reliability, and power quality control. Distribution control was a sideline issue when central station economies of scale dominated the electric power industry, but this situation has changed.

The new emphasis is on the distribution sector, which is ready for massive applications of technology that control and manage the end user's consumption. AMR software and hardware are aimed at the distribution sector; load management is a distribution function.AMR products will also have load management capability. Consequently, there's a clear need for processing capability.But where will that capability be located, at the company's headquarters or at selected points in the field, such as a central office?

The processing capability should be located in the field, making the logical choice for processing in an intelligent network digital central office switches. All organizations, including utilities, would probably recoil at the idea of a digital central office that processes data, fearing for the data's privacy and reliability. Appropriate encryption and validation procedures would make processing viable at the central switch, and provide two separate opportunities for cooperation between a phone company and an energy utility: where the local company does not have a digital switch, coordination between the two utilities could result in the installation of a new digital switch. Where a digital switch already exists, joint investment in its distributed processing capability will expand the intelligent network's scope. A utility's data bases could be placed in the central switch and accessed on a LATA basis. Without this capability, the intelligent network may be a case of bandwidth overkill for AMR and load management functions, with no thought given to the network's potential for time differentiated pricing or other add-on services for utilities.



Property and Profit

An intelligent network's product improvement is tied directly to software, a concrete, easily recognized aspect of the intelligent network.But in a radio network product improvement is amorphous because a frequency cannot be "owned", and there are no codified private property rights regarding the spectrum. Government steps in to allocate the spectrum.In a competitive setting, lack of property rights in the spectrum makes the innovator's profit stream far less secure than for the intelligent network's innovator.In a competitive setting property rights protect the profit stream created by the innovator. For this reason, an intelligent network is more likely to sustain a high rate of innovation than a radio network.In fact, one of the more notable innovations in radio technology thrives on the absence of property rights. Spread spectrum technology hops across adjacent radio frequencies to mask the content of a radio message.While this is successful in military applications, the technology has not yet penetrated the commercial markets to a significant degree.

Product improvement is important for radio-based AMR manufacturers. They will have to demonstrate their product's potential for broad application over time before they can capture the utility industry as a long-term AMR customer.

Dr. Stephen N. Brown is Chief, Bureau of Energy Efficiency, Auditing, and Research Utilities Division, Iowa Department of Commerce. This paper was presented at the New Mexico State University's Center for Public Utilities: Current Issues Challenging the Regulatory Process held in Santa Fe, New Mexico March 11, 1992.

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Opinion

No Second Time Around for AMR

By Stephen Brown, AMRA Treasurer
Iowa Department of Commerce

David Gorton's editorial in AMRA's January newsletter ["Looking Back to See the Future," p. 2] conveyed the notion that AMR's problems are no different today than they were 30 years ago. To an extent, he is right. AMR's problems are perennial because the utility industry's retail business environment has been remarkably stable. But the time will come when the environment changes, allowing a permanent fix for the infirmities of the AMR market.

Utilities have a growing need for accurate and prompt measurement of consumption. This is not caused by a sense of righteous conversion to AMR. Cold, hard self-interest is the reason. The electric and gas utilities, in particular, are more interested in AMR today because they face the prospect of competition in all phases of their business. Competition implies uncertainty about profit margins and a need for detailed knowledge of the retail market. Good information acquired through AMR will make the difference between success and failure in a competitive market.

Standard and Poor's Corp., a major financial ratings firm, believes that competition is making the electric business very risky. Consequently, the firm set new financial standards that may reduce credit ratings for one-third of the nation's electric utilities. This has never happened before. The industry's new competitive environment may compel utilities to install AMR equipment that embodies rapid communication and sophisticated measurement. Thus, the recycling of AMR's familiar problems may truly come to a final end.

However, Gorton's editorial shows the same thought being voiced in 1967: "AMR has been a 'want' of the electric utilities for many years but now is rapidly becoming a 'must.'" That statement was wrong in 1967, but it's right today. If you want to know why, read an insightful article by AMRA member Roger Levy. He cowrote *Reengineering DSM: Opportunities Through Information and Integration*, which appears in last November's issue of *The Electricity Journal*. Levy explains why the electric utility industry failed, in general, to implement automation procedures regarding measurement and communication in the retail market. The dominant reason, says Levy, is "most ... technical and procedural designs incorporate implicit and explicit compromises to make sure that programs cause little disruption and conform as closely as possible to the operating practices and features of existing utility company business management and information systems."

In short, AMR and all automation systems have the potential to create ripple effects throughout a company. If unwilling to live with these or take advantage of them, the company constrains the automation project, cutting it here and tweaking it there until the project is reduced to a shadow, drained of its promise and potential.

In Levy's words, "What starts out as a 'logical compromise' ... artificially limits how ... communication, measurement and control technologies might be used to modernize existing utility systems and practices."

In today's market, many industries depend on rapid information flow for marketing, cost cutting and competing, including: the overnight package delivery industry, the vending machine business, the liquid fuels business of propane and butane delivery, and all "just-in-time" production and inventory businesses. These enterprises have made every effort to automate because it's vital to their success.

In 1967, automation at the retail level didn't mean anything to the utility industry, and AMR was a nonevent. That era is over. The AMR industry should take advantage of the present, push on all fronts and think big.

The advice of Daniel Burnham is appropriate. He was a urban planner who, in 1900, redesigned the cities of Chicago and Washington, D.C. He told the cities' leaders, "Make no small plans, they do not stir men's imagination."

AMR pilot projects have seen their day. The technology won't mature if it's forever limited to trials. Its true potential lies in full-scale, utilitywide projects, and now is the time to pursue them.

Stephen Brown works for the Iowa Department of Commerce, which is based in Des Moines. He also serves as the treasurer of AMRA.

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Opinion

DOE Proposal Trivializes AMR

By Stephen Brown
Iowa Department of Commerce

Automatic meter reading (AMR) received much needed attention when Congress enacted the Telephone Disclosure and Dispute Resolution Act of 1992. It directed the U.S. Department of Energy (DOE) to consider a government demonstration project involving utility communications and AMR.

Last March, the DOE opened docket CE-NOI-93-001, an inquiry meant to implement Congress' directive. After consultation with the U.S. Commerce Department, the DOE released its final report, *Proposal for Demonstrating the Potential of Innovative Communications Equipment and Services for Utility Applications*, on Sept. 2. [See related article on page 3.] In it, the DOE recommends against a "use of federal funds" to develop an AMR or energy-management demonstration project because "it would duplicate demonstrations already planned by utilities."

Despite this reasonable conclusion, the final document is disappointing. It could have been a means for the DOE to show Congress that meter reading and utility communication are vital functions in the American economy. Instead, the DOE sent Congress a message that trivializes AMR.

The report accepts without question a cliched, moss-backed argument used for years to stifle innovation in metering, utility pricing and communication: "Presently the main limitation on automatic meter reading is cost. According to the Edison Electric Institute in their response, a survey of their members shows that it only costs between 30 cents and 60 cents per customer per month to read the meter manually for typical customers...". When Congress reads this, they will wonder why anyone would bother with AMR since manual reading is cheaper than a phone call.

The report is flawed because the agency's world view is confined to the Washington Beltway. Twenty-seven respondents filed comments on CE-NOI-93-001. The DOE apparently thinks only two had opinions that are worthy of Congress' attention. The DOE highlights the filings of the Edison Electric Institute and the Utility Telecommunications Council, two of the oldest guards in Washington. The report does not refer to the opinions of the other 25 respondents — vendors, phone companies, cable companies, utilities and consultants. A balanced report would have drawn from many respondents, not just two. It would have shown the fallacy of the "manual meter reading is cheap" argument.

Manual meter reading is cheap because it is an almost worthless service. It gives practically nothing to consumers and utilities. The inadequacy of meter reading and its failure to facilitate economic decision making by consumers is shown by the popularity of balanced-billing for gas, water and electric utilities.

In balanced-billing, a customer's annual bill is estimated and divided by 12. The result is the customer's monthly bill. At the end of one year, the difference between actual and estimated consumption is reconciled, the customer receives a credit or debit, and the cycle starts again. Millions of consumers use balanced-billing. In short, the payment for consumption of gas, water and electricity in the United States is little different from making a premium payment for insurance. The success of balanced-billing shows the only effective use of manual meter reading — reconciling the customer's estimated annual consumption against actual consumption once a year in order to balance a company's annual cash flow.

It is a mystery why the DOE gladly accepts the cheap meter-read argument and then passes it on to Congress as an unquestioned truth. Consumers need the opportunity and the tools to treat their energy and water purchases like any other commodity or service. AMR is the tool, and a time-sensitive utility price is the opportunity. These will create new patterns of energy and water use, perhaps allowing the next generation of Americans to mitigate and avoid costs for such things as the safe disposal of nuclear fuel used in power plants, which is now estimated at $45 billion.

With AMR, the next generation will shop for the right time to buy energy, from the right source and at the right price — just like it shops for the right groceries and right times to travel. It's time for the utility industry's metering practices to measure up to the 1990s and the next century.

The DOE's report could have sent these messages to Congress while still arriving at the same conclusions. Instead, Congress will now dismiss the issue as trivial.

Stephen Brown works for the Iowa Department of Commerce. He also serves as the treasurer of AMRA.

ECONOMIC INCENTIVES FOR NUCLEAR PLANT PERFORMANCE: A STATE PERSPECTIVE

BY

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STATE OF IOWA

DELIVERED AT THE NRC'S STATE LIAISON OFFICERS' MEETING: REGION III
GLEN ELLYN, ILL., SEPTEMBER 29, 1988

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INTRODUCTION

I had the opportunity to listen to Nuclear Regulatory Commissioner Ken Rogers' presentation at the July 25th meeting of NARUC's subcommittee on nuclear issues. Commissioner Rogers clearly takes the position that capacity factors can be a disincentive to the safe operation of a nuclear power plant when they are used as a sole measure of the plant's overall economic performance. Of course, the Commissioner's stance accurately represents the Nuclear Regulatory Commission's (NRC's) basic opinion regarding target capacity factors and their role in the incentive programs established by state regulatory bodies.

I'm a senior staff member of a state regulatory body, the Iowa Utilities Division, a group that provides line and staff support to the Iowa Utilities Board, a body composed of three appointed officials, the decision-makers who set policy. I do not speak for their policy views on incentive programs. But I am in the position to describe why nuclear plant performance is becoming an issue in Iowa, to make my own professional assessment of the capacity factor issue, and to offer a compromise measure, one that may satisfy the concerns of the NRC and those of state regulatory agencies engaged in economic incentive programs.

NUCLEAR POWER IN IOWA

Nuclear power plants provide approximately 25% of the net electrical generation devoted to consumption in Iowa. The plants are: Cooper, wholely owned and operated by Nebraska Public Power, but one-half of the net output is committed to the Iowa Power & Light Company; Duane Arnold, operated by Iowa Electric Light & Power Company, but jointly owned with two rural electric organizations; and Quad Cities Units 1 and 2, operated by Commonwealth Edison, but jointly owned with Iowa-Illinois Gas & Electric Company.

Nuclear plants are normally operated at a nearly constant level of output during most on-line hours, the exception being those on-line hours either immediately prior to a planned shut-down or during coast-down at the end of the fuel cycle. But the Utilities Division Staff found that Cooper and Duane Arnold substantially deviated from this pattern; from 1983 through

1986 both plants appeared to swing with load rather than operating in the base-load fashion characteristic of most other nuclear plants in the country. Table 1 is a comparison of Duane Arnold and Cooper utilization to utilization of nuclear plants in states adjacent to Iowa. For all four years these two plants were consistently near the bottom of the scale. Table 2 is a similar comparison for nuclear plants in the Mid-Continent Area Power Pool (MAPP), and Cooper and Duane Arnold again fall to the bottom of the scale. Tables 3 and 4 are similar comparisons using all the nuclear plants.

All of this descriptive information substantiates the idea that these two plants, unlike most others in the country, were not being extensively base loaded. This is significant because of the very low fuel costs involved: between 6 and 9 mills per kilowatt-hour at both plants in comparison to costs of 13 to 15 mills at the large coal-fired plants in the state. The very obvious question is: why not increase the output at the nuclear plants as a substitute for the more expensive coal output? This issue is even more puzzling because one of the state's base-load coal fired plants has greater utilization than either Cooper or Duane Arnold during the same time frame. The Iowa Utilities Board ordered an investigation into this issue; interrogatories were sent to the two Iowa companies involved, and responses are expected in mid-October.

This approach appears to be retrospective, but it should also be viewed as a planning consideration. Federal acid rain legislation could have a negative impact on eight major generating plants in Iowa. If and when such legislation becomes law, compliance would most likely require curtailed output at some or all of these plants. As a group, the plants provide 4,600 megawatt hours (MWH) of the state's net electrical output, about 21 percent of the total net output. In addition, the plants' average number of annual service hours exceed 7,000, and the average hourly output is 82 megawatts (MW). Improved performance at the nuclear plants will alleviate some of the negative consequences of compliance with the new legislation. This is a primary reason why nuclear power plant performance in Iowa will be more important in the future.

THE CAPACITY FACTOR ISSUE

Given the scenario just described, how should a regulatory body proceed with the development performance evaluation? A quick answer, but one that would disturb the NRC, would be to use capacity factors. As most of you know, a capacity factor is a composite measure of a plant's availability and output level. If availability falls or if output declines, the capacity factor drops. The NRC's objection to capacity factors is simple but cogent: use of the factor encourages a company to run a nuclear plant when it should be shut down for periodic and preventive maintenance. Therefore, capacity factors lead to incremental deterioration of the plant with a cumulative effect on safety. New York Attorney General Robert Abrams expressed this sentiment when criticizing the New York PSC's incentive program: "A company striving to meet a capacity-factor target would be tempted to ignore or downplay the seriousness of safety problems."

This argument is aimed at state regulatory agencies. These organizations have a direct and large effect on the financial well-being of the utilities involved with the nuclear plants. From a financial view, the state bodies have a much greater impact on the companies than does the NRC. For this reason, state agencies can have substantial influence on how the companies manage nuclear plants. In fact, several states have chosen to exercise their influence, and despite the concerns of the NRC, have adopted incentive programs that include capacity factors. These states include New York, New Jersey, Florida, Virginia, and North Carolina among others. The contention and fractiousness over economic incentives and regulation is quite visible.

For example, a July 1988 Electrical World article summarized a nuclear plant survey conducted by the Reliability Engineering Department of Westinghouse Electric:

> ...organizational and external factors have a far stronger effect on availability of US reactors than physical attributes, such as age, reactor type, or nuclear-steam-supply-system vendor...Economic regulation sometimes hinders preventive-maintenance initiatives and plant equipment upgrades, the report concluded. "On the state level, there appears to be a widespread lack of understanding by utility commissions of the importance of nuclear power..."

The other side of the coin is illustrated by a December 1985 article appearing in the New York Times:

> ...(S)tate regulators seem unimpressed with the NRC's concerns and suggestions. "This is a political process," said one state regulator, adding that the NRC's protestations about the deleterious effect of financial incentive programs on reactor safety are "a nice smokescreen."

There appears to be disagreement between many state regulatory authorities, the nuclear power industry, and the NRC over the use of incentive programs and capacity factors. The most important question here is not who's right, but is there an alternative, one that is tenable for all concerned parties?

I believe that the answer lies in a composite measure that incorporates three ideas: (1) the utilization ratio concept illustrated in Tables 1 through 4; (2) service hours; and (3) reactor trip rates, referred to more formally as Reactor Protection System Actuation Rates.

DEVELOPING A COMPOSITE MEASURE

The utilization ratios in Tables 1 through 4 exclude hours when the plant is not in service, and therefore provide a simple indication about the kind of loading that prevails at the nuclear plant. The ratios are useful because they indicate if an economic dispatch problem is present. An

economic dispatch problem is clearly not a plant performance problem, but this distinction would be hidden by capacity factors. By mixing availability and output level, capacity factors fail to pinpoint and isolate system problems from plant problems.

However, utilization ratios shed no light on plant availability; they are useless in this regard. Plant availability should be synonymous with service hours; this method is simple, clear, and avoids any confusion that might be caused by using capacity factors as a surrogate measure for availability. But there is an important point here; if capacity factors should not be used in an economic incentive program, then how can the capacity factor concept be legitimately used by generation planners when they're assessing the economic feasibility of a new plant? The link between capacity factors used for planning and actual capacity factors is shown in a February 1987 decision by the New Jersey Board of Public Utilities. The following is taken from the decision and order in Docket ER85121163.

> Nuclear plants are constructed with the expectation that their high capital costs will be offset by their low operating costs, thereby providing an economical, year-round energy supply to ratepayers. At the time the decisions were made to construct each of the Company's five operating nuclear plants - Salem I, Salem II, Peach Bottom II, Peach Bottom III and Hope Creek I- they were projected to perform at approximately 80% capacity factors. These projections were subsequently revised downward at the time construction commenced and again at the time of initial commercial operation. Despite these projections, the plants (exclusive of Hope Creek) have not met performance expectations and have been plagued with prolonged outages. The Company reported that the lifetime cumulative capacity factor for Salem I is 51.3%, Salem II - 47.7%, Peach Bottom II - 53.8% and Peach Bottom III - 60%. Further, plant operations have been characterized by wide swings in performance as evidenced by Salem II's 8% capacity factor in 1983 and Salem I's 95% capacity factor in 1985. Thus, ratepayers have been saddled with the cost burden of the plants' high fixed costs in base rates and expensive replacement power costs incurred as a result of substandard nuclear performance ... It is this history of uneven and substandard nuclear performance, its attendant cost burden to ratepayers and the Company's increasing reliance on nuclear generation that gives rise to the need for nuclear performance standards.

Repudiating capacity factors in an economic incentive program also means repudiating them in the generation planning and economic feasibility stage. How is this contradiction resolved to create a workable incentive program, one that also addresses the concerns of the NRC and the criticism of capacity factors voiced by New York State Attorney General, Robert Abrams, mentioned earlier? I believe the answer lies in the use of reactor trip rates.

The concept is clearly explained in a well-documented paper authored by David Dietrich of Technical Analysis Corporation. He makes several points in his paper, and I'm going to highlight just two of them because they're useful in this forum. The author makes this statement:

> An "RPS actuation with control rod motion" -- the standard terminology meaning reactor scram or shutdown -- results in lower economic efficiency because the plant is taken off line. Such an RPS actuation also results in a lower level of safety because the event presents a challenge to safety systems and operating staff that must bring the reactor to a safe condition.

With this comment Mr. Dietrich is establishing a connection between a reactor trip and economic efficiency; the greater the number of trips the lower the overall efficiency. In the next statement the author points out how well reactor trip rates coincide with the NRC's policy goals.

> The NRC has had a formal program to reduce trip frequency since 1984 and every year has seen a gradual reduction in trip rates. The NRC has concluded that "a reduction in the frequency of challenges to plant safety systems should be a prime goal of each licensee." It also finds that large reductions in the risk of an anticipated transient without scram (ATWS) can be achieved by reducing the frequency of transients that call for RPS operation. A reduction in the RPS actuation rate, the goal of the proposed incentive program criterion, is not only consistent with formal NRC policy. It is formal NRC policy.

However, reactor trip rates are not complete substitutes for capacity factors; although the two items are inversely correlated with each other, the correlation is not perfect. David Dietrich points out that while low trip rates are accompanied by high capacity factors and vice-versa, there are also instances where high capacity factors and high trip rates accompany each other. Based on this observation, my conclusion is that reactor trip rates alone should not be the only criteria to evaluate the economic performance of a nuclear plant.

CONCLUSION

In my opinion an economic incentive program should explicitly include reactor trip rates because they are useful and prudent, as well as being responsive to the concerns of the NRC. But I continue to believe that utilization levels and the number of plant service hours should also be a part of an incentive program. The exact weight given to each component would be a matter for the policy makers. The conceptual framework provided here represents a middle road, one that does not rely on a single measure to evaluate performance. An incentive program focusing on reactor trip rates, utilization levels, and service hours provides a workable alternative to reliance on target capacity factors and is a solution to the problem I mentioned earlier: where a company or industry repudiates capacity factors as a method of economic evaluation even

though generation planners used capacity factors to justify economic feasibility for the plants in question. Use of the composite measure put forth in this paper would certainly recognize the interests of the ratepayers, the companies, and the concerns for safety expressed by the NRC.

TABLE 1

Comparison of Cooper and Duane Arnold Utilization to
Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	Palisades	MI	812.00	635.00	3,769,958	5,283.60	713.52	112.37%
2.	1986	Kewaunee	WI	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
3.	1985	Kewaunee	WI	560.00	503.00	3,699,176	7,214.70	512.73	101.93%
4.	1984	Kewaunee	WI	560.00	503.00	3,810,000	7,528.40	506.08	100.61%
5.	1984	Point Beach #1	WI	524.00	485.00	3,109,208	6,380.00	487.34	100.48%
6.	1983	Kewaunee	WI	560.00	503.00	3,706,928	7,335.80	505.32	100.46%
7.	1985	Point Beach #1	WI	524.00	485.00	3,354,176	6,919.30	484.76	99.95%
8.	1986	Point Beach #1	WI	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
9.	1985	Point Beach #2	WI	524.00	485.00	3,603,081	7,491.30	480.97	99.17%
10.	1985	Palisades	MI	812.00	730.00	5,301,797	7,344.40	721.88	98.89%
11.	1986	Point Beach #2	WI	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
12.	1984	Point Beach #2	WI	524.00	485.00	3,512,373	7,406.60	474.22	97.78%
13.	1983	Point Beach #2	WI	524.00	495.00	3,016,298	6,247.60	482.79	97.53%
14.	1984	Cook #2	MI	1,133.00	1,060.00	5,364,363	5,198.70	1,031.87	97.35%
15.	1983	Cook #2	MI	1,133.00	1,060.00	7,013,579	6,838.40	1,025.62	96.76%
16.	1986	Wolf Creek #1	KS	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
17.	1986	Zion #2	IL	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
18.	1984	Palisades	MI	812.00	635.00	811,549	1,336.30	607.31	95.64%
19.	1984	Callaway #1	MO	1,188.00	1,120.00	323,023	302.50	1,067.84	95.34%
20.	1986	Big Rock Pt. #1	MI	60.00	64.00	506,148	8,361.70	60.53	94.58%
21.	1985	Wolf Creek #1	KS	1,250.00	1,128.00	2,942,100	2,771.60	1,061.52	94.11%
22.	1984	La Crosse	WI	65.00	48.00	318,604	7,067.30	45.08	93.92%
23.	1984	Zion #2	IL	1,098.00	1,040.00	5,986,311	6,180.00	968.66	93.14%
24.	1983	Zion #2	IL	1,098.00	1,040.00	6,181,965	6,406.60	964.94	92.78%
25.	1984	Cook #1	MI	1,152.00	1,020.00	7,550,755	8,017.80	941.75	92.33%
26.	1983	Cook #1	MI	1,152.00	1,020.00	5,286,839	5,630.80	938.91	92.05%
27.	1985	Cook #2	MI	1,133.00	1,060.00	5,683,634	5,855.00	970.73	91.58%
28.	1985	Callaway #1	MO	1,236.00	1,120.00	8,045,764	7,884.90	1,020.40	91.11%
29.	1984	Zion #1	IL	1,098.00	1,040.00	5,692,090	6,030.40	943.90	90.76%
30.	1985	Zion #1	IL	1,098.00	1,040.00	4,813,949	5,107.40	942.54	90.63%
31.	1984	Dresden #2	IL	828.00	772.00	4,460,360	6,403.70	696.53	90.22%
32.	1986	Callaway #1	MO	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%
33.	1985	Lasalle #2	IL	1,078.00	1,036.00	3,430,898	3,699.90	927.29	89.51%
34.	1986	Dresden #2	IL	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
35.	1985	La Crosse	WI	65.00	48.00	322,909	7,597.60	42.50	88.54%
36.	1983	Big Rock Pt. #1	MI	60.00	64.00	348,591	6,222.80	56.02	87.53%
37.	1984	Lasalle #2	IL	1,078.00	1,036.00	1,392,117	1,537.40	905.50	87.40%
38.	1986	Cook #1	MI	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
39.	1986	Palisades	MI	812.00	730.00	841,244	1,324.40	635.19	87.01%
40.	1983	Dresden #2	IL	828.00	772.00	3,397,514	5,080.30	668.76	86.63%
41.	1986	Zion #1	IL	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
42.	1984	Big Rock Pt. #1	MI	60.00	70.00	417,523	6,906.20	60.46	86.37%
43.	1985	Dresden #3	IL	828.00	773.00	4,390,064	6,621.30	663.02	85.77%
44.	1985	Dresden #2	IL	828.00	772.00	3,087,488	4,680.40	659.66	85.45%

TABLE 1 (Cont.)

Comparison of Cooper and Duane Arnold Utilization to
Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
45.	1986	Lasalle #2	IL	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
46.	1986	Bryon #1	IL	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
47.	1983	Dresden #3	IL	828.00	773.00	4,147,939	6,403.10	647.80	83.80%
48.	1986	Lasalle #1	IL	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
49.	1985	Zion #2	IL	1,098.00	1,040.00	5,114,186	5,901.30	866.62	83.33%
50.	1985	Cook #1	MI	1,152.00	1,020.00	2,116,062	2,491.10	849.45	83.28%
51.	1985	Lasalle #1	IL	1,078.00	1,036.00	4,809,395	5,584.90	861.14	83.12%
52.	1984	Lasalle #1	IL	1,078.00	1,036.00	5,206,209	6,055.00	859.82	82.99%
53.	1984	D.A.E.C.	*	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
54.	1984	Dresden #3	IL	828.00	773.00	2,105,646	3,311.10	635.94	82.27%
55.	1983	D.A.E.C.	*	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
56.	1986	La Crosse	WI	65.00	48.00	157,179	3,998.10	39.31	81.90%
57.	1985	Big Rock Pt. #1	MI	60.00	69.00	362,428	6,441.70	56.26	81.54%
58.	1986	D.A.E.C.	*	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
59.	1986	Cooper	*	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
60.	1983	La Crosse	WI	65.00	48.00	201,267	5,232.60	38.46	80.13%
61.	1985	D.A.E.C.	*	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
62.	1983	Cooper	*	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
63.	1984	Cooper	*	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
64.	1986	Dresden #3	IL	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
65.	1986	Cook #2	MI	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
66.	1985	Bryon #1	IL	1,175.00	1,129.00	1,012,898	1,192.40	849.46	75.24%
67.	1985	Cooper	*	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
68.	1983	Point Beach #1	WI	524.00	495.00	2,384,844	6,499.20	366.94	74.13%
69.	1983	Zion #1	IL	1,098.00	1,040.00	4,016,176	5,742.20	699.41	67.25%
70.	1983	Lasalle #1	IL	1,078.00	1,036.00	1,639,809	3,085.90	531.39	51.29%
71.	1986	Fermi #2	MI	1,215.00	1,093.00	-23,926	437.70	-54.66	-5.00%
72.	1983	Bryon #1	IL	--	--	--	--	--	--
73.	1984	Bryon #1	IL	--	--	--	--	--	--
74.	1983	Callaway #1	MO	--	--	--	--	--	--
75.	1983	Fermi #2	MI	--	--	--	--	--	--
76.	1984	Fermi #2	MI	--	--	--	--	--	--
77.	1985	Fermi #2	MI	--	--	--	--	--	--
78.	1983	Lasalle #2	IL	--	--	--	--	--	--
79.	1983	Wolf Creek #1	KS	--	--	--	--	--	--
80.	1984	Wolf Creek #1	KS	--	--	--	--	--	--

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC.

1983-1986 Est. Average MW Generation and Utilization of Nuclear Plants Participating in Mapp

No.	Year	Plant Name	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	D.A.E.C.	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
1.	1984	D.A.E.C.	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
1.	1985	D.A.E.C.	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
1.	1986	D.A.E.C.	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
2.	1983	Quad Cities #1	828.30	769.00	5,776,352	8,261.00	699.23	90.93%
2.	1984	Quad Cities #1	828.30	769.00	3,349,735	4,687.00	714.69	92.94%
2.	1985	Quad Cities #1	828.30	769.00	6,072,319	8,244.00	736.57	95.78%
2.	1986	Quad Cities #1	828.30	769.00	4,420,669	5,880.00	751.81	97.77%
3.	1983	Quad Cities #2	828.30	769.00	3,151,307	5,622.00	560.53	72.89%
3.	1984	Quad Cities #2	828.30	769.00	4,983,925	6,840.00	728.64	94.75%
3.	1985	Quad Cities #2	828.30	769.00	4,556,866	6,248.00	729.33	94.84%
3.	1986	Quad Cities #2	828.30	769.00	4,722,778	6,401.50	737.76	95.94%
4.	1983	Cooper	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
4.	1984	Cooper	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
4.	1985	Cooper	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
4.	1986	Cooper	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
5.	1983	Monticello	569.00	525.00	4,147,725	8,439.00	491.49	93.62%
5.	1984	Monticello	569.00	525.00	263,119	808.80	325.32	61.97%
5.	1985	Monticello	569.00	536.00	4,286,986	8,030.60	533.83	99.60%
5.	1986	Monticello	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
6.	1983	Prairie Island #1	593.00	503.00	3,888,853	7,624.20	510.07	101.40%
6.	1984	Prairie Island #1	593.00	503.00	4,159,389	8,286.80	501.93	99.79%
6.	1985	Prairie Island #1	593.00	503.00	3,677,016	7,334.60	501.32	99.67%
6.	1986	Prairie Island #1	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
7.	1983	Prairie Island #2	593.00	500.00	3,716,220	7,578.10	490.39	98.08%
7.	1984	Prairie Island #2	593.00	500.00	3,905,956	7,831.10	498.77	99.75%
7.	1985	Prairie Island #2	593.00	500.00	3,608,478	7,378.20	489.07	97.81%
7.	1986	Prairie Island #2	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
8.	1983	Fort Calhoun #1	502.00	456.00	2,749,832	6,405.00	429.33	98.02%
8.	1984	Fort Calhoun #1	502.00	478.00	2,331,771	5,264.90	442.89	92.65%
8.	1985	Fort Calhoun #1	502.00	478.00	3,066,254	6,455.50	474.98	99.37%
8.	1986	Fort Calhoun #1	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
9.	1983	Total MAPP	5,346.75	4,783.00	29,097,806	54,983.30		
9.	1984	Total MAPP	5,346.75	4,823.00	25,181,411	46,025.60		
9.	1985	Total MAPP	5,346.75	4,834.00	28,276,152	50,287.90		
9.	1986	Total MAPP	5,346.75	4,834.00	30,864,251	57,003.60		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC.
Northwest Power Cooperative has Genoa #2 listed as a nuclear plant in the 1986 MAPP Load and Capacity Report, but Genoa was not listed in the The Licensed Operating Reactors Status Summary Report for 1983-1986.

TABLE 3

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,830,738	6,856.40	850.41	103.08%
2.	Robinson #2	South Carolina	769.00	665.00	4,798,026	7,030.10	682.50	102.63%
3.	Kewaunee	Wisconsin	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
4.	Calvert Cliffs #2	Maryland	911.00	825.00	7,006,666	8,408.70	833.26	101.00%
5.	St. Lucie #2	Florida	850.00	839.00	6,146,561	7,255.50	847.16	100.97%
6.	St. Lucie #1	Florida	890.00	839.00	7,052,031	8,353.60	844.19	100.62%
7.	Ginna	New York	517.00	470.00	3,610,266	7,659.90	471.32	100.28%
8.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,392,716	8,322.30	167.35	100.21%
9.	Maine Yankee	Maine	864.00	810.00	6,241,756	7,694.80	811.17	100.14%
10.	Three Mile Island #1	Pennsylvania	871.00	776.00	4,818,263	6,212.30	775.60	99.95%
11.	Point Beach #1	Wisconsin	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
12.	Turkey Point #3	Florida	760.00	666.00	4,513,059	6,820.50	661.69	99.35%
13.	Palo Verde #2	Arizona	1,403.00	1,221.00	2,654,603	2,195.00	1,209.39	99.05%
14.	Arkansas #2	Arkansas	943.00	858.00	5,305,213	6,276.00	845.32	98.52%
15.	Millstone #1	Connecticut	662.00	654.00	5,247,940	8,176.20	641.86	98.14%
16.	Waterford #3	Louisiana	1,153.00	1,075.00	7,301,595	6,924.80	1,054.41	98.08%
17.	Point Beach #2	Wisconsin	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
18.	Limerick #1	Pennsylvania	1,138.00	1,055.00	6,848,850	6,636.00	1,032.08	97.83%
19.	Prairie Island #2	Minnesota	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
20.	Farley #2	Alabama	860.00	824.00	5,959,872	7,458.30	799.09	96.98%
21.	Summer #1	South Carolina	900.00	885.00	7,160,639	8,350.90	857.47	96.89%
22.	Prairie Island #1	Minnesota	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
23.	Mcguire #2	North Carolina	1,305.00	1,150.00	6,209,772	5,604.60	1,107.98	96.35%
24.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
25.	Farley #1	Alabama	860.00	825.00	5,726,616	7,216.80	793.51	96.18%
26.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,851,048	4,988.80	1,172.84	96.06%
27.	Quad Cities #2	Illinois	828.00	769.00	4,722,778	6,401.50	737.76	95.94%
28.	Millstone #3	Connecticut	1,253.00	1,142.00	5,861,760	5,355.90	1,094.45	95.84%
29.	Zion #2	Illinois	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
30.	Surry #1	Virginia	848.00	781.00	4,488,628	6,015.80	746.14	95.54%
31.	Fitzpatrick	New York	883.00	794.00	6,015,605	7,932.20	758.38	95.51%
32.	Vermont Yankee #1	Vermont	563.00	504.00	2,058,426	4,281.20	480.81	95.40%
33.	Quad Cities #1	Illinois	828.00	769.00	4,420,669	6,037.10	732.25	95.22%
34.	Beaver Valley #1	Pennsylvania	923.00	810.00	4,778,500	6,196.50	771.16	95.21%
35.	San Onofre #2	California	1,127.00	1,070.00	6,361,900	6,267.70	1,015.03	94.86%
36.	Surry #2	Virginia	848.00	781.00	4,498,941	6,075.00	740.57	94.82%
37.	Millstone #2	Connecticut	910.00	857.00	5,160,945	6,354.20	812.21	94.77%
38.	Oconee #1	South Carolina	934.00	860.00	4,784,795	5,872.60	814.77	94.74%
39.	Oconee #2	South Carolina	934.00	860.00	5,801,065	7,124.50	814.24	94.68%
40.	Trojan	Oregon	1,216.00	1,075.00	7,090,231	6,985.30	1,015.02	94.42%
41.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	5,830,291	5,995.20	972.49	94.23%
42.	Hatch #1	Georgia	850.00	750.00	3,645,387	5,164.40	705.87	94.12%
43.	North Anna #1	Virginia	947.00	915.00	6,310,739	7,330.90	860.84	94.08%
44.	Brunswick #1	North Carolina	867.00	790.00	5,973,813	8,069.90	740.26	93.70%
45.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	6,896,565	7,014.00	983.26	93.55%
46.	Pilgrim #1	Massachusetts	678.00	670.00	1,027,531	1,646.00	624.26	93.17%
47.	Turkey Point #4	Florida	760.00	666.00	1,721,504	2,792.10	616.56	92.58%
48.	Salem #1	New Jersey	1,170.00	1,106.00	7,079,276	6,923.80	1,022.46	92.45%
49.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	5,448,219	5,734.20	950.13	92.07%
50.	Brunswick #2	North Carolina	867.00	790.00	2,911,036	4,029.60	722.41	91.44%
51.	Mcguire #1	North Carolina	1,305.00	1,150.00	5,164,769	4,916.00	1,050.60	91.36%
52.	North Anna #2	Virginia	947.00	915.00	6,022,050	7,210.50	835.18	91.28%
53.	Fort Calhoun #1	Nebraska	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
54.	Indian Point #2	New York	1,013.00	849.00	3,810,597	4,926.80	773.44	91.10%
55.	Monticello	Minnesota	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
56.	Oyster Creek #1	New Jersey	674.00	620.00	1,301,476	2,310.90	563.19	90.84%
57.	Oconee #3	South Carolina	934.00	860.00	6,064,306	7,782.80	779.19	90.60%
58.	Callaway #1	Missouri	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 3 (Cont.)

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
59.	Diablo Canyon #2	California	1,164.00	1,079.00	6,548,174	6,730.50	972.91	90.17%
60.	Nine Mile Point #1	New York	642.00	610.00	3,146,883	5,724.10	549.76	90.12%
61.	Dresden #2	Illinois	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
62.	Salem #2	New Jersey	1,162.00	1,106.00	5,312,561	5,416.90	980.74	88.67%
63.	San Onofre #3	California	1,127.00	1,080.00	6,760,591	7,070.80	956.13	88.53%
64.	Crystal River #3	Florida	890.00	821.00	2,653,212	3,661.30	724.66	88.27%
65.	Catawba #1	South Carolina	1,305.00	1,145.00	5,182,492	5,155.00	1,005.33	87.80%
66.	Big Rock Point #1	Michigan	60.00	69.00	506,148	8,361.70	60.53	87.73%
67.	Cook #1	Michigan	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
68.	Palisades	Michigan	812.00	730.00	841,244	1,324.40	635.19	87.01%
69.	Zion #1	Illinois	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
70.	Indian Point #3	New York	1,013.00	1,000.00	5,525,581	6,432.40	859.02	85.90%
71.	Diablo Canyon #1	California	1,137.00	1,073.00	5,293,267	5,758.20	919.26	85.67%
72.	Catawba #2	South Carolina	1,305.00	1,145.00	1,297,202	1,325.80	978.43	85.45%
73.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	4,849,352	5,545.30	874.50	84.49%
74.	Lasalle #2	Illinois	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
75.	Bryon #1	Illinois	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
76.	Lasalle #1	Illinois	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
77.	La Crosse	Wisconsin	65.00	48.00	157,179	3,998.10	39.31	81.90%
78.	Duane Arnold	Iowa	597.00	515.00	3,008,073	7,181.10	418.89	81.34%
79.	Cooper Station	Nebraska	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
80.	Haddam Neck	Connecticut	600.00	569.00	2,132,316	4,698.90	453.79	79.75%
81.	Arkansas #1	Arkansas	903.00	836.00	3,573,159	5,447.70	655.90	78.46%
82.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,183,198	6,134.40	844.94	77.16%
83.	Hatch #2	Georgia	850.00	761.00	3,618,712	6,172.70	586.24	77.04%
84.	Dresden #3	Illinois	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
85.	Cook #2	Michigan	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
86.	River Bend #1	Louisiana	990.00	936.00	2,995,439	4,225.70	708.86	75.73%
87.	San Onofre #1	California	450.00	436.00	874,187	2,731.50	320.04	73.40%
88.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	4,098,054	5,330.50	768.79	67.32%
89.	Hope Creek #1	New Jersey	1,118.00	1,067.00	1,030,793	1,679.00	613.93	57.54%
90.	Fort St. Vrain	Colorado	343.00	330.00	52,007	1,087.10	47.84	14.50%
91.	Davis-Besse #1	Ohio	962.00	860.00	3,486	116.60	29.90	3.48%
92.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-36,374	0.00	0.00	0.00%
93.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-47,061	0.00	0.00	0.00%
94.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-41,625	0.00	0.00	0.00%
95.	Fermi #2	Michigan	1,215.00	1,093.00	-23,916	437.70	0.00	0.00%
96.	Rancho Seco #1	California	963.00	873.00	-32,157	0.00	0.00	0.00%
97.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-40,178	0.00	0.00	0.00%
98.	Sequoyah #2	Tennessee	1,220.00	1,148.00	-64,434	0.00	0.00	0.00%
	Total		90,675.00	83,271.00	407,666,034	538,038.70		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,268,477	6,237.00	844.71	102.39%
2.	Robinson #2	South Carolina	769.00	665.00	4,230,329	6,226.30	679.43	102.17%
3.	Three Mile Island #1	Pennsylvania	871.00	776.00	5,034,307	6,353.60	792.36	102.11%
4.	Kewaunee	Wisconsin	560.00	503.00	4,008,624	7,811.00	513.20	102.03%
5.	Prairie Island #2	Minnesota	593.00	500.00	4,429,989	8,760.00	505.71	101.14%
6.	Ginna	New York	517.00	470.00	3,797,701	7,994.00	475.07	101.08%
7.	Arkansas #2	Arkansas	943.00	858.00	6,605,168	7,681.70	859.86	100.22%
8.	Point Beach #1	Wisconsin	524.00	485.00	3,567,092	7,350.30	485.30	100.06%
9.	St. Lucie #1	Florida	890.00	839.00	5,715,344	6,814.10	838.75	99.97%
10.	Calvert Cliffs #2	Maryland	911.00	825.00	4,831,976	5,861.60	824.34	99.92%
11.	San Onofre #3	California	1,127.00	1,080.00	7,519,728	6,987.80	1,076.12	99.64%
12.	Point Beach #2	Wisconsin	524.00	485.00	3,606,145	7,481.10	482.03	99.39%
13.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	8,598,435	8,431.60	1,019.79	98.82%
14.	Prairie Island #1	Minnesota	593.00	503.00	3,590,268	7,234.20	496.29	98.67%
15.	St. Lucie #2	Florida	850.00	839.00	5,950,184	7,209.70	825.30	98.37%
16.	Millstone #2	Connecticut	910.00	857.00	6,892,531	8,180.10	842.60	98.32%
17.	Millstone #1	Connecticut	662.00	654.00	4,377,008	6,827.10	641.12	98.03%
18.	Fort Calhoun #1	Nebraska	502.00	478.00	3,060,620	6,531.70	468.58	98.03%
19.	Palo Verde #2	Arizona	1,403.00	1,221.00	8,190,044	6,858.20	1,194.20	97.80%
20.	Waterford #3	Louisiana	1,153.00	1,075.00	7,425,710	7,087.80	1,047.67	97.46%
21.	Oconee #3	South Carolina	934.00	860.00	5,084,967	6,069.90	837.73	97.41%
22.	Surry #1	Virginia	848.00	781.00	4,633,405	6,116.90	757.48	96.99%
23.	Vermont Yankee #1	Vermont	563.00	504.00	3,536,411	7,290.60	485.06	96.24%
24.	Hatch #1	Georgia	850.00	750.00	5,076,654	7,046.00	720.50	96.07%
25.	San Onofre #2	California	1,127.00	1,070.00	6,230,341	6,068.30	1,026.70	95.95%
26.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,504,145	6,013.00	1,081.68	95.89%
27.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,268,268	4,504.50	1,169.56	95.79%
28.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,135,611	7,100.70	159.93	95.77%
29.	Indian Point #2	New York	1,013.00	849.00	5,146,333	6,333.00	812.62	95.72%
30.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	7,726,991	7,100.00	1,088.31	95.30%
31.	Farley #1	Alabama	860.00	825.00	6,444,862	8,203.10	785.66	95.23%
32.	Mcguire #1	North Carolina	1,305.00	1,150.00	7,348,715	6,715.80	1,094.24	95.15%
33.	Surry #2	Virginia	848.00	781.00	4,790,953	6,457.90	741.87	94.99%
34.	Summer #1	South Carolina	900.00	885.00	5,151,897	6,136.90	839.50	94.86%
35.	Beaver Valley #1	Pennsylvania	923.00	810.00	5,620,890	7,322.90	767.58	94.76%
36.	Millstone #3	Connecticut	1,253.00	1,142.00	6,742,317	6,234.60	1,081.44	94.70%
37.	Mcguire #2	North Carolina	1,305.00	1,150.00	7,572,577	6,957.10	1,088.47	94.65%
38.	Haddam Neck	Connecticut	600.00	569.00	2,527,207	4,700.50	537.65	94.49%
39.	Quad Cities #1	Illinois	828.00	769.00	4,456,087	6,141.70	725.55	94.35%
40.	Quad Cities #2	Illinois	828.00	769.00	4,952,988	6,836.20	724.52	94.22%
41.	Catawba #1	South Carolina	1,305.00	1,145.00	6,377,839	5,928.60	1,075.77	93.95%
42.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	6,127,879	6,333.00	967.61	93.76%
43.	Monticello	Minnesota	569.00	536.00	3,533,357	7,052.90	500.98	93.47%
44.	Lasalle #2	Illinois	1,078.00	1,036.00	4,542,494	4,700.20	966.45	93.29%
45.	Nine Mile Point #1	New York	642.00	610.00	4,615,169	8,130.50	567.64	93.06%
46.	Farley #2	Alabama	860.00	824.00	4,902,626	6,397.80	766.30	93.00%
47.	Diablo Canyon #1	California	1,137.00	1,073.00	8,284,201	8,342.80	992.98	92.54%
48.	Oyster Creek #1	New Jersey	674.00	620.00	3,110,919	5,422.90	573.66	92.53%
49.	Vogtle #1	Georgia	1,157.00	1,084.00	3,921,520	3,920.40	1,000.29	92.28%
50.	Maine Yankee	Maine	864.00	810.00	4,042,901	5,415.40	746.56	92.17%
51.	Diablo Canyon #2	California	1,164.00	1,079.00	5,715,218	5,754.50	993.17	92.05%
52.	Callaway #1	Missouri	1,236.00	1,120.00	6,321,776	6,143.90	1,028.95	91.87%
53.	Turkey Point #4	Florida	760.00	666.00	2,636,070	4,318.90	610.36	91.65%
54.	Hope Creek #1	New Jersey	1,118.00	1,067.00	7,277,090	7,457.10	975.86	91.46%
55.	Zion #2	Illinois	1,098.00	1,040.00	5,114,145	5,384.50	949.79	91.33%
56.	North Anna #2	Virginia	947.00	915.00	5,653,448	6,785.50	833.17	91.06%
57.	Harris #1	North Carolina	950.00	860.00	3,378,829	4,323.60	781.49	90.87%
58.	River Bend #1	Louisiana	990.00	936.00	4,964,440	5,837.70	850.41	90.86%
59.	Brunswick #1	North Carolina	867.00	790.00	4,046,631	5,652.30	715.93	90.62%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4 (Cont.)

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
60.	Palisades	Michigan	812.00	730.00	2,634,430	3,983.10	661.40	90.60%
61.	Hatch #2	Georgia	850.00	761.00	5,755,607	8,390.40	685.98	90.14%
62.	Zion #1	Illinois	1,098.00	1,040.00	6,058,385	6,482.40	934.59	89.86%
63.	Indian Point #3	New York	1,013.00	1,000.00	4,850,586	5,399.90	898.27	89.83%
64.	Fitzpatrick	New York	883.00	794.00	4,198,340	5,894.80	712.21	89.70%
65.	Duane Arnold	Iowa	597.00	515.00	2,540,837	5,514.80	460.73	89.46%
66.	Catawba #2	South Carolina	1,305.00	1,145.00	7,169,495	7,019.00	1,021.44	89.21%
67.	Perry #1	Ohio	1,250.00	1,205.00	828,484	773.40	1,071.22	88.90%
68.	Big Rock Point #1	Michigan	60.00	69.00	374,931	6,132.20	61.14	88.61%
69.	Salem #1	New Jersey	1,170.00	1,106.00	6,211,441	6,363.20	976.15	88.26%
70.	Salem #2	New Jersey	1,162.00	1,106.00	6,172,052	6,343.40	972.99	87.97%
71.	Brunswick #2	North Carolina	867.00	790.00	5,694,104	8,205.80	693.91	87.84%
72.	Beaver Valley #2	Pennsylvania	923.00	885.00	738,104	949.80	777.12	87.81%
73.	Oconee #1	South Carolina	934.00	860.00	5,028,061	6,694.70	751.05	87.33%
74.	Trojan	Oregon	1,216.00	1,075.00	4,347,772	4,631.60	938.72	87.32%
75.	Cooper Station	Nebraska	836.00	764.00	5,522,126	8,292.40	665.93	87.16%
76.	Dresden #3	Illinois	828.00	773.00	4,395,502	6,595.70	666.42	86.21%
77.	North Anna #1	Virginia	947.00	915.00	3,568,907	4,525.50	788.62	86.19%
78.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	1,552,256	1,724.00	900.38	85.67%
79.	Limerick #1	Pennsylvania	1,138.00	1,055.00	5,318,987	5,926.70	897.46	85.07%
80.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	1,460,062	1,659.60	879.77	85.00%
81.	San Onofre #1	California	450.00	436.00	2,708,001	7,323.40	369.77	84.81%
82.	Oconee #2	South Carolina	934.00	860.00	6,228,692	8,567.10	727.05	84.54%
83.	Crystal River #3	Florida	890.00	821.00	3,620,784	5,263.80	687.87	83.78%
84.	Cook #1	Michigan	1,152.00	1,020.00	5,033,767	5,918.80	850.47	83.38%
85.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,397,981	5,981.00	902.52	82.42%
86.	Turkey Point #3	Florida	760.00	666.00	856,146	1,567.70	546.12	82.00%
87.	Clinton #1	Illinois	NA	933.00	684,103	898.30	761.55	81.62%
88.	Dresden #2	Illinois	828.00	772.00	3,342,347	5,345.30	625.29	81.00%
89.	Davis-Besse #1	Ohio	962.00	860.00	5,063,984	7,312.40	692.52	80.53%
90.	Bryon #1	Illinois	1,175.00	1,129.00	5,330,576	6,007.30	887.35	78.60%
91.	Bryon #2	Illinois	1,175.00	1,120.00	1,970,901	2,280.40	864.28	77.17%
92.	Cook #2	Michigan	1,133.00	1,060.00	5,026,564	6,251.60	804.04	75.85%
93.	Arkansas #1	Arkansas	903.00	836.00	4,763,342	7,723.10	616.77	73.78%
94.	Lasalle #1	Illinois	1,078.00	1,036.00	4,073,067	5,456.80	746.42	72.05%
95.	Braidwood #1	Illinois	NA	1,120.00	1,456,651	2,610.70	557.95	49.82%
96.	Palo Verde #3	Arizona	1,403.00	1,221.00	319,661	620.70	515.00	42.18%
97.	Fermi #2	Michigan	1,215.00	1,093.00	1,392,801	4,084.20	341.02	31.20%
98.	Fort St. Vrain	Colorado	343.00	330.00	180,922	2,030.40	89.11	27.00%
99.	Nine Mile Point #2	New York	1,214.00	1,080.00	260,995	1,059.00	246.45	22.82%
100.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-12,718	0.00	0.00	0.00%
101.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-34,470	0.00	0.00	0.00%
102.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-50,980	0.00	0.00	0.00%
103.	Pilgrim #1	Massachusetts	678.00	670.00	0	0.00	0.00	0.00%
104.	Rancho Seco #1	California	963.00	873.00	-56,759	0.00	0.00	0.00%
105.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-48,236	0.00	0.00	0.00%
106.	Sequoyah #2	Tennessee	1,220.00	1,148.00	-59,378	0.00	0.00	0.00%
	Total		98,682.00	92,731.00	449,087,064	584,375.40		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

END NOTES

[1] Tables 1 and 2 are drawn from a report authored by Shari Cameron of Utilities Division, Department of Commerce, State of Iowa. A full reference appears in the Bibliography. Tables 3 and 4 were prepared by Leighann O'Tool of the Utilities Division, Department of Commerce, State of Iowa.

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Bubble Memory Technology: Its Impact on Metering and Rate Structure

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Supervisor of Rate Design
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Bubble memory will replace magnetic tape as the principal means of implementing product differentiation and rate structures within the electric utility industry for two reasons: first, research and commercial development of bubble memory technology is moving forward after the technology was abandoned by several U.S. producers. Advances in the technology will reduce the importance of silicon and increase the importance of ferrous magnetic substances by achieving very high density rates of bit storage, which in turn will bring economies of scale and rapidly declining average costs for the storage of information. Second, bubble memory's performance already exceeds that of magnetic tape, and the difference between these levels of performance will become even greater.

The remainder of this discussion is divided into three parts: the first is a brief explanation of how product differentiation in the electric utility industry creates a need for efficient information storage; the second is a comparison of magnetic tape and bubble memories; and the third section explains why bubble memory technology is viable, marketable, and dependable.

I

In the context of an electric utility, product differentiation means that electric power sales represent several different services that are distinguished from one another by such criteria as the time of the sale, the customer making the purchase, whether the sale is short-term, long-term, intermittent, or continuous, and any other criteria that would be relevant. Product differentiation naturally entails different prices for different commodities. For example, electric power subject to interruption is clearly a different commodity than power not subject to interruption; similarly, electric power sold at the time of the system's peak demand is different from power sold at another time.

A utility that charges for its product on a time-of-day basis has to know the moment-by-moment purchases of a customer; such information becomes voluminous in a matter of hours and must be processed, evaluated, and stored. Since charging for power sales on a time-of-day basis is now a regular feature of many utilities' rate structure; and since interruptable and standby power sales are becoming more common both to industrial customers and to other utilities, even more information (and storage) will be required. These needs will rapidly exceed the capabilities of magnetic tape as a sales recording device.

II

Bubble memory is a storage medium in solid state form, in which the presence or absence of a "bubble" in a submicroscopic magnetic domain on a chip represents respectively a 0 or a 1, so that data can be stored in binary form. Unlike other kinds of memory, bubble memory has no moving parts and is nonvolatile (i.e., not power-dependent): it retains recorded data even if the power supply is interrupted. [1] Although magnetic tape also retains data when the power supply is interrupted, measurement of consumption using magnetic tape entails a mechanical system installed and reset manually, the shortcomings of which make possible inaccurate measurement of consumption and concomitantly lower revenue. This is readily demonstrated by an examination of the steps required for magnetic tape to measure power consumption by an industrial customer on a time-of-day rate.

The tape of a magnetic tape meter is usually divided into two or more tracks: one track always records time pulses sent from an external clock, while the other tracks record data pulses that represent power consumption. The time pulses are recorded according to a predetermined interval length. Consumption within a time period is determined by adding up the number of data pulses recorded between two adjacent time pulses. Once an initial start time is determined, all time pulses will occur at those regular intervals that subdivide the billing period. For example, if the start time is 9:00 and the interval length is 15 minutes, the time pulses occur at 9:15, 9:30, 9:45, and so on.

While this may seem simple to implement theoretically, practically it poses several problems. Magnetic tape metering requires extensive training of the personnel that install, maintain, and remove the tapes from the metering site. A tape metering system is essentially a mechanical system, insofar as it relies on the tape drive gears to operate properly and move the tape at the required number of inches per second; otherwise the space between adjacent time pulses may not represent the time interval specified by the utility. Referring to the example above, the interval could represent 9:00 to 9:12, or 9:03 to 9:20 depending on the speed of the tape drive.

The metering tapes also have nonmagnetic leaders and trailers, which record nothing [2] so that when the tape begins, it must be positioned properly for the initial time and data pulses to fall on the magnetic portion. Otherwise there is a mismatch between tape start time and recorded information, causing a loss of information, and in metering situations, loss of information usually means loss of

revenues.

There is another possibility for error. The tape must be replaced before the magnetic trailer is reached, or billing information is lost at this stage, too. This means that the tape must be physically replaced; therefore, the utility must follow a precise schedule not only to read the tapes but to replace them as well.

There are other problems. The initial start time of the first interval on the tape must be set from an external clock, one that runs independently of the tape. The interval length can only be changed by changing the external clock. While this is not a problem for a single meter, it would be a very expensive problem, in terms of labor costs, where several hundred meters are involved. So once a utility selects an interval's starting point and its length, change is a problem.

All of these points underscore the importance of trained personnel in maintaining, setting, and reading the meters. But this also highlights the vulnerability of billing in the event of a labor strike.

Performance characteristics are particularly important in metering situations because the storage medium is subject to the extremes of weather: heat, cold, humidity, and dust. How does magnetic tape hold up compared with bubble memory under these conditions?

Magnetic tape expands with heat and contracts with cold, ages, wrinkles, and develops ripples. The recording head is subject to oxide buildup and must be regularly cleaned [3]. Any of these can cause data loss or data error, so that the tape is incorrectly read and translated to a mainframe computer. Bubble memories produced by Intel Magnetics can operate within a range of 0 to 70 Celsius [4]; the limits of the range will expand to -20 and 85 Celsius in the very near future [5]. Bubble memory is minimally affected by dust, vapor, vibration [6], and hard radiation [7], even in very harsh environments. It maintains data integrity.

Furthermore, the reliability of bubble memory is a distinct advantage to a utility's metering capability. The failure rate for a 128K bubble memory device is 1 in 10 to the 15th power; this is about once in every 100 years of operation [8]. The mean repair time (i.e., for replacement) of a bubble memory unit is only a few minutes [9]. The reliability of a magnetic tape system is far less simply because it is a mechanical system [10]; a major portion of any magnetic tape storage system involves mechanically operated systems-control and -drive hardware.

Another point of comparison is storage capacity, and magnetic tape used in metering situations has a maximum capacity of 3 M bits/square inch [11]. In 1983, Intel Magnetics introduced a 4M bit chip measuring 1.46 x 1.35 centimeters with a storage capacity of slightly more than 2 M bits per square centimeter or 5 M bits per square inch [12]. On this basis, bubble memory has a 60capability of magnetic tape does not apply in metering situations because increasing data storage on tape at a metering site requires decreasing the speed at which the tape moves and because there is a limit to how slow a tape can be set to move [13]. For example, for data collected on a 15-minute interval basis, tapes used in metering situations have a practical storage limit of 90 days. Bubble memory, on the other hand, has no moving parts; its full storage capacity can always be utilized as this capacity continues to increase with technological advances. Bubble memory already has a capacity in the range of 6 months for 15-minute intervals and 2 months for 5-minute intervals. Unlike magnetic tape, bubble memory technology offers the possibility of remote readings over telephone lines or other data transmission paths. Telephone interrogation of magnetic tapes is not practical. Remote data access and bubble memory technology also offer the possibility of automatic reprogramming from a central source of all interval lengths and start times for all meters simultaneously.

The foregoing clearly implies that the use of bubble memory would be substitution of capital for labor, thereby providing greater management control over the entire process. More important, however, is the flexibility (that does not now exist) in a utility's rate structure that bubble memory can provide. Consider the following as a case in point. For billing purposes, the practical minimum interval length on a magnetic tape is 15 minutes. This interval length cannot accurately measure power used in time periods that are shorter than the interval and that overlap interval boundaries.

For example, given the 15-minute interval beginning at 9:00, there is no way to measure the power flow from 9:07 to 9:22, and this is particularly important where large inductive loads operate intermittently and where the operation of these loads is timed to circumvent the real measure of the power flow; for example, if an electric drag line or an electric furnace is used between 9:07 and 9:22, the power flow measure on a magnetic tape meter with 15-minute intervals described above would only capture half the actual power flow. In this situation, the unmeasured power sales become system-demand losses to the utility. These losses usually range from 5 percent to 10 percent of a utility's net generation.

However, a bubble memory using a one-minute or five-minute interval would solve this problem by recording a higher sales volume, leading to lower system-demand losses and to either greater revenue for a given sales price or lower prices because of a given revenue requirement. This could have a substantial industry-wide effect by bringing in several hundred millions of dollars that are otherwise lost or by keeping electrical price levels lower. Furthermore, bubble memory's capability to record power usage accurately no matter how short the duration will also provide for more precise cost-of-service studies, enhance the utility's ability to sell interruptible power, and thereby more fully utilize spinning reserve. The last point of comparison to be made here between bubble memory and magnetic tape is data access. At one time, both magnetic tape and bubble memory entailed sequential access to data; the only way to access data in the middle of stored information was by accessing all information leading up to what was desired. Improvements in chip architecture for bubble memories now make data access time two to four times faster than either hard or floppy

disk drive access times [14] Of course, data access time on a magnetic tape cannot be improved by manipulating the medium, and this further demonstrates that bubble memory storage is superior to tape storage

III

Major factors in adopting any new technology are expected life and serviceability. Bubble memory is not new, but it is still a fairly recent development. The driving force behind the discovery of magnetic bubbles was a group of scientists at Bell Laboratories, prominent among them A.H. Bobeck, U.F. Gianola, R.C. Sherwood, H.E.D. Scovil, and W. Shockley [15] Theoretical discoveries in the late 1960's by the Bell group gave impetus to further research and attempts at commercial development throughout the 1970's. Research has been conducted along several lines of development: materials analysis, chip architecture, and chip fabrication, to mention a few. At one time in the late 1970's, development programs were underway at Texas Instruments, National Semiconductor, Rockwell International, Motorola, Intel, and Signetics. Bell Labs developed an experimental 11.5 M bit bubble device only 1.3 inches square; even Hewlett Packard developed applications in desktop calculators [16] All of this is sufficient indication that the bubble memory market was perceived as one that would grow and be viable. In the late seventies, there was a consensus that the annual sales volume in the United States would approach 1 billion dollars and that the technology would cost only 10 millicents per bit [17] but by 1981 Intel was the only domestic producer of bubble memory: all the others had abandoned the market.

Far from being sidelined in terms of research and development, bubble memory remains viable because it is ideally suited for portable applications and because of its radiation- hardness. For example, in the mid-1970's it was considered for inclusion as a component for an on-board attitude control computer for spacecraft [18] Research on magnetic bubbles continues in Japan, Britain, France, West Germany, and the Soviet Union. From the standpoint of development, in the United States, Intel negotiated a "second source" agreement with Motorola in 1982, so that technological research, product development and manufacture of bubble memory will be shared between the two firms [19] This is significant because bubble memory will have a full line of support electronics, the lack of which had previously hampered commercial development. Furthermore, research done by IBM at San Jose determined that "magnetic bubble memories must have a capacity of at least 4 M bits to challenge RAM devices on the basis of cost." [20] It is no coincidence, therefore, that Intel introduced a 4 M bit chip in 1983. This is a clear signal that further commercial development of bubble memory is anticipated: A 16 M bit device is the next logical step [21] and it could be available by the early 1990's. Research is under way at Hitachi, Fujitsu, Sagem [22] IBM, and Bell Labs [23] It must not be forgotten that the original corporate developer of the bubble memory, Bell Labs and its parent AT&T, were prevented from entering the computer technology market. But this has all changed with the recent divestiture of AT&T. It is only logical to conclude that the founder of the technology would seek to commercialize and expand it now that legal restrictions are removed from commercial competition in the industry.

Further development of the technology can be expected because of the tremendous potential for miniaturization and scale economies in bubble fabrication In fact, scale economies are already occuring. In 1979 Intel published a series of guaranteed prices for bubble devices purchased in quantities of 25,000. The prices of devices were $1000 in 1980, $600 in 1981, and $300 in August of 1982. By January of 1983, the prices fell below $250 in lots of 10,000 [24] The price of the 4 M bit device is expected to approach $150 by 1986 [25] Achieving low-cost chips requires high device density and large chip capacity. The complementary technologies to achieve this are either in place or undergoing advancement themselves. For example, the Intel 4 M chip referred to earlier in this essay was fabricated using x-ray lithography [26] this is the production tool that enabled the achievement of 4 M bit density, but as time and research continue, x-ray lithography can be expected to give way to electron beam lithography [27] the ultimate key to bubble miniaturization and scale economies.

The ongoing research and commercial development makes a myth of the notion that bubble memory is a dead technology. The complexities of the utility industry are already outdistancing the capabilities of the magnetic tape, and new avenues must be investigated. Bubble memory is a viable and superior option to develop for the long term.

Conclusion

Some of the technological differences between magnetic tape and magnetic bubble memory have been discussed and policy implications briefly outlined. The industry cannot ignore the technological changes that are coming in the 1980's and 1990's. The limitations of magnetic tape necessitate a vigorous search for a suitable substitute, one that does not allow data error/loss in metering, one that can measure interruptible and standby power and insure against revenue erosion by means of interval adjustment, one that allows for remote monitoring using data communications technology, and one that makes for greater flexibility in the development of rate structures.

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The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Stephen N. Brown

The FERC completed a remarkable turnaround in regulatory philosophy in its gas pipeline restructuring order.

Competition for natural gas supply will promote the nation's economic growth. That idea describes the essence of Federal Energy Regulatory Commission (FERC) Order No. 636 and provides the driving force behind the commission's effort to restructure the natural gas industry. But the FERC's eventual success ultimately depends on the spirit of "cooperative competition": The willingness of individual players to share information about day-to-day pipeline operations and the vital conditions that determine rate design and prices.

The FERC itself is acutely aware of this vulnerability. That is why the commission framed Order 636 with language that simultaneously coaxes, cajoles, and urges the industry to do its patriotic duty (see box).

This language makes FERC's order 636 truly remarkable. It tells the pipelines that their traditional way of doing business blocks the spread of competition within the natural gas industry. This finding was unthinkable twenty years ago. The natural gas industry was built on the principle of bundled, city-gate, firm sales service. During the industry's early years, certificates of convenience and necessity were issued to pipelines only if they offered such service to distribution companies. The industry's building block is now an unlawful restraint of trade.

The pipelines' old virtue is now a vice because the merchant function is gradually fading away. In the first quarter of 1984 pipeline sales made up 94 percent of throughput. By the second quarter of 1991 pipeline sales totaled only 12 percent of throughput. Nevertheless, in 1991 pipeline sales consumed over 60 percent of peak-day capacity. This surprising mismatch between throughput and capacity told the FERC that pipeline sales enjoy a clear advantage over the open-access firm transportation of nonpipeline natural gas:

Free-flowing Information

The FERC intends to solve the fairness problem by establishing equivalency between bundled, city-gate firm sales by the pipeline and open-access firm transportation of nonpipeline natural gas. The solution lies with the idea of "No-Notice Transportation Service." Success will depend on cooperation between the various segments of the industry, as the FERC is quite aware:

> [We] expect the pipelines and all interested participants to craft . . . the operating conditions needed to

The Spirit of 636

Drawing on Patriotism:

"[We] . . . remind the industry that it is in the nation's best interest and the industry's interest . . . to keep gas flowing and deliverable when and where needed and . . . not unreasonably inhibit the meeting of gas purchasers and gas sellers in a competitive market." [Order No. 636, p. 96.]

From Virtue to Vice:

"[The] pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry . . . this harm has an unreasonable impact on gas sellers and is an unlawful restraint of trade." [Order No. 636, p. 39.]

To Level the Field:

"Pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors." [Order No. 636, p. 32.]

An Open Book, But Who Will Read It?

Pipelines In a Fishbowl:

Pipelines will retain operational control, but will perform in a fishbowl, since all buyers and sellers must now constantly monitor pipeline operations.

Second-guessing by Customers:

Buyers and sellers are likely to develop "shadow" operations groups that not only will monitor operating conditions, but are also likely to second-guess the pipelines from time to time.

Information Overload:

A tremendous need will arise for accurate, speedy, and voluminous information on storage facilities, receipt and delivery points, pressure, pumping stations, capacity reallocations, and anything else that might be viewed as relevant.

ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlement on a daily basis without incurring daily balancing and scheduling penalties.

To its lasting credit, the FERC recognizes that "no-notice" markets will not be fully competitive without another simultaneous development — the rapid and free flow of information. The FERC clearly says "that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations." This policy will work only if all players cooperate. Any effort to tilt the scales by withholding or disguising relevant information may easily subvert the FERC's goal of uniting gas purchasers and gas sellers in a competitive market place. The importance of good and timely information cannot be overestimated for a competitive market, whether it's the New York Stock Exchange, the Chicago Board of Trade, or the natural gas industry.

The FERC's policy on information flow has major implications. The pipelines may not yet have realized that the order lays out their operations for all to see. It's just like letting one person cut the cake while others choose which piece they want. For example, the pipelines must make electronic bulletin boards accessible to all users and no one will be granted preferential access to the boards:

> The pipelines must keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records . . . pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information.

The FERC is right to be cautious, considering the impending modernization of the nation's telecommunications infrastructure and uncertain behavior of the players in the natural gas industry. How will the new infrastructure affect the competitiveness of the natural gas industry? Will the pipelines really want to give up their advantage of occupying 60 percent of the peak-day capacity, particularly when their sales are less than 20 percent of annual throughput? Do local distribution companies (LDCs) really want to jump into a competitive market with complexities that rival those of a major stock exchange? Will the upstream and downstream pipelines really cooperate with one another?

Rate Design

The restructuring hearings will not deal with the single biggest rate design issue for pipelines: transportation cost recovery through the "straight fixed-variable method" (SFV). This rate design definitely affects the central feature of the FERC's restructuring proposal: The presumed willingness of gas buyers to participate in "no-notice transportation service."

The SFV method removes all fixed costs from the pipeline's commodity charge for transporting gas. For years the FERC allowed significant amounts of fixed costs in the pipeline's commodity charge. The commission now believes such practice inhibits competition by preventing gas purchasers from making accurate comparisons of prices, terms, and conditions offered by various gas sellers. The SFV method corrects this mistake and promotes "head-to-head, gas-on-gas competition."

The FERC prefers the SFV rate design but suggests that it may be avoided by any particular pipeline if the parties agree on an alternative costing method. If the parties can't persuade the FERC to deviate from its preference, or if they lack a consensus on rate design, the SFV method will prevail. The odds favor SFV, since rate design is rarely characterized by harmony. It's an impossible goal because the customers' load factors are too diverse. In fact, the SFV method reduces costs for customers with high annual load factors, and increases costs for customers with poor load factors. This explains both the support and the opposition to SFV — with a rate design consensus unlikely, there will be no viable alternative.

The SFV method will increase costs for some customer groups. The FERC has agreed to limit such increases to 10 percent and to phase in the increase over a four-period after the pipeline's initial compliance filing. But after four years, the phase-in terminates and the limitations expire for SFV-related cost increases. After that customers are on their own; they must adapt to changed circumstances. The burden cannot be laid at the door of producers or pipelines. It falls exclusively on gas consumers and perhaps their agents acting as gas purchasers.

What does this mean for hot new designer rates? It means that "no-notice" transportation rates must strongly

reflect the prevailing operating conditions on the pipeline.

I'm not advocating a different price for every hour of the year on every different section of the line. But I am advocating that the industry get far away from the idea that "one rate fits all." The nature of a competitive market place allows for some tailoring and customizing of individual prices and contract terms. Indeed, if the market doesn't exhibit these characteristics at all, then it's not really a competitive market. Customizing may be one way to develop a "no-notice" competitive transportation market. There's certainly room for this market considering that interruptible transportation now accounts for 51 percent of pipeline deliveries to market.

Tailored rate designs ought to reflect a match between the customers needs, the producer's supply, and the pipeline's operating conditions. This brings me back to my emphasis on the need for good information. More than ever before, there will be an emphasis on the optimal scheduling of pipeline flows, storage, maintenance, controlling, and shifting consumer demand. In this situation command and control of information is paramount because a competitive market inevitably reduces profit margins for the poorly organized and inefficient party. To be effective negotiators, gas purchasers and sellers must have the ability to recognize and act on the opportunities offered by the ebb and flow of a pipeline's operating conditions. FERC clearly understands this and accordingly has decided to make pipeline operations an open book for both gas buyers and sellers.

I hope LDCs and their customers are ready for the responsibilities of a competitive natural gas market. The LDCs fit the national pattern already noted by the FERC: Buying a lot of gas on the spot market, using interruptible transportation, and relying on pipeline sales for peak-day purchases, while keeping overall bills below the potential cost of exclusive reliance on pipeline gas. The LDCs have had an extended learning opportunity. It's up to them to take this experience and skillfully apply it the emerging market that the FERC is now creating.

The competitive market certainly raises uncertainties at the federal and state levels. How will the FERC draw the boundary between proprietary information and information required to make the market competitive? How does state regulation establish risk-sharing between the core customers and an LDC making a gas purchase on their behalf? Will a purchased gas adjustment (PGA) clause continue to serve a useful purpose once pipelines comply with Order 636?

These questions don't exhaust the possibilities, but sooner or later, perhaps in a rate case setting or in a notice of inquiry, the LDCs will have to show their state regulatory body that they've read the open book on pipeline operations and made good use of it. This would serve everyone's interest, and the LDCs should avoid putting truth to old sayings: "You can lead a horse to water but you can't make it drink," or, in the case of pipeline operations, "seeing a book open does not make its reader think."

Order 636-A: A Short-term Solution?

On July 30 the FERC met and voted to approve Order No. 636-A, in which it slightly relaxed its effort to push the natural gas industry into the information age. Pipeline capacity released for less than one calendar month will now require neither advanced posting on electronic bulletin boards nor bidding.

But the practicality of omitting short-term transactions from posting and bidding requirements will diminish as the industry learns better how to handle transactions of various sizes and duration. These short-term events cause a nuisance only when the players in the market are not ready to use or interpret the information that they provide. Any competitive market features short-term, low-volume transactions, and there is no inherent reason why such transactions should hinder a competitive market in its allocative efficiency. Thus, we can likely expect that the FERC will eventually withdraw Order 636-A and replace it in a subsequent rule making.

Competition Versus Reliability

The importance of pipeline operations cannot be overstated because major changes in public policy towards regulated industry are constrained by technical considerations. The FERC's restructuring efforts are no exception. At the inception of the "Mega-NOPR," pipeline system reliability was incompatible with competition — one condition precluded the other. With the industry's help, the FERC resolved this apparent contradiction and found that system reliability and competition coexist. Neither one preempts the other.

With a little imagination, the FERC might apply this reasoning to the issue of transmission access in the electric power industry. All that's needed is to substitute "electric utility" for "pipeline" and "no-notice transmission" for "no-notice transportation". Can the FERC make competition in the electric industry compatible with system reliability? Perhaps not, but the electric industry may soon be hard pressed to explain why system reliability and competition cannot coexist in the power industry.

The FERC has offered a number of individual steps that, if taken quickly and cooperatively, will speed the gas industry's adoption of competitive market practices. But I emphasize the *fragility* of the FERC's proposal and the need for cooperation to make the system work. Hot new designer rates won't sell in the market place if the players torpedo the restructuring. I agree with the unspoken sentiment expressed by the FERC: Restructuring the industry will work only if the players adopt the spirit of "cooperative competition." That should characterize all bargaining between sellers, buyers, and pipelines.

Stephen N. Brown is chief of the Bureau of Energy Efficiency, Auditing and Research, Utilities Division, of the Iowa Utilities Board.

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Twenty-five years of experience with the Public Utility industry:

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2004 - Present Office of the Attorney General for the State of Tennessee - Consumer Advocate and Protection Division - Regulatory Analyst

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Direct Testimony: http://www.state.tn.us/tra/dockets/0700224.htm

TRA #07-00105 Atmos Energy Corporation
Direct Testimony: http://www.state.tn.us/tra/orders/2007/0700105cg.pdf

TRA # 06-00290 Tennessee American Water Company
Direct Testimony: http://www2.state.tn.us/tra/dockets/0600290.htm

TRA # 06-00175 Chattanooga Gas Company

Direct Testimony: http://www2.state.tn.us/tra/dockets/0600175.htm

TRA # 05-00258 Atmos Energy Corporation
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TRA #98-00626 UTSE

TRA #97-00982 Chattanooga Gas Company

TRA #96-00977 Nashville Gas Company

TPSC #95-02258 United Cities Gas Company

TPSC #95-02116 Chattanooga Gas Company

TPSC #94-02876 BellSouth Telecommunications

PSC #92-13527 South Central Bell - Earnings Investigation for the years 1993-1995 (Copy of Testimony Not Available)

Docket N/A GTE - Rate Filing
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Before the

TENNESSEE PUBLIC SERVICE COMMISSION

Nashville, Tennessee

In Re:

South Central Bell Telephone Company

Docket 94-02876

****

Direct Testimony

of

Terry Buckner

****

November 18, 1994

Q. Please state your name for the record.

A. My name is R. Terry Buckner.

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

A. I am employed by the Consumer Advocate Division (CA) in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. How long have you been employed in the utility industry?

A. Approximately seventeen years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission (Commission) as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems (TDS) for eight years and the First Utility District of Knox County for three years.

Q. What is your educational background and what degrees do you hold?

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. Would you briefly describe your responsibilities as a Senior Regulatory Analyst since your employment with the CA?

A. My responsibilities include evaluating financial data, submitting data

requests to Companies, making recommendations to the Director of the CA Division and the Consumer Advocate, and preparing testimony and exhibits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present information to the Commission as to the reasonableness of the proposed tariff filing #94-223 by South Central Bell (SCB) in Docket #94-02876 regarding the establishment of regulations, rates, and charges for the provision of Directory Assistance (DA) services in Tennessee.

Q. Would you please identify the general issues regarding Docket #94-02876?

A. The Consumer Advocate has filed a motion with the Commission to dismiss SCB's request to impose a charge for DA in Tennessee. In the filed motion, it is the Consumer Advocate's contention that SCB's filing was in fact improperly filed according to Commission rules and that the filing is inappropriate and untimely.

Additionally, the CA received responses from SCB to our data request dated November 1, 1994 on November 14, 1994. The CA staff is presently reviewing SCB's responses many of which were inadequate or were not responded to due to SCB's objections. On November 17, 1994, the CA spoke with counsel for SCB and SCB agreed to provide additional information which may offset other

issues.

Q. Would you please identify the specific issues regarding Docket #94-02876?

The specific issues within the filing are as follows:

(1) Whether the filing is valid and appropriate under rule 1220-4-2-.55. In exchange for the opportunity to make excessive profits by cutting costs and inefficiencies, SCB agreed that it would not initiate any requests to adjust its earnings except in accordance with rule 1220-4-2-.55. SCB is not to initiate any requests and the Commission is not to entertain any unless and until the situation comes within the provision of the rule.

The rule requires that SCB not initiate any adjustment unless its earnings are 60 basis points below its prescribed rate of return. The 60 basis points translates into 6/10 of 1% or .60%. SCB's prescribed rate of return is 11.25%. Using simple math to subtract .60% from 11.25%, one arrives at 10.65% as the point at which SCB can legitimately request an adjustment to its earnings. The Commission Staff knows SCB's most recent report of its earnings in relationship to its prescribed rate of return through the submission of the Commission monthly report 3.01. The Commission 3.01 report for August 1994 shows that SCB is earning 10.79% for the last twelve months to date. Therefore it is clear on its face to SCB and the

Commission Staff that there are no grounds to consider this earnings adjustment. The CA believes that this proceeding is illegal, illegitimate and very irregular. It is contrary to both the spirit and the letter of rule 1220-4-2-.55. In addition, it is contrary to what prompted that rule which was to encourage SCB to reduce its expenses and to improve its efficiency. SCB does neither with this particular earnings increase, so therefore it goes even against the policy behind the rule. Certainly, SCB is not offering to reduce any costs or improve its efficiencies by this particular rate increase or rate proposal. SCB has not shown that it is threatened or that the consumer's interests are jeopardized by denying this earnings adjustment. Simply put, SCB is proposing to reduce service that it is presently providing to its customers.

The CA would first say that this matter should be dismissed outright and that there was no need for this hearing in the first place if SCB complied with the rule. The Commission should dismiss this proceeding in its entirety and deny SCB any adjustment to its earnings;

(2) The determination of the 50% destimulation factor used by SCB to calculate revenue is not factually supported in their filing and calls into question the projected earnings increase identified by SCB. In addition, the imposition of the directory assistance charge will likely

increase revenues in the future from the Company's electronic white page offering. The Company has not included the additional revenue from this service in its projection;

(3) A local call allowance of 5 residential and 3 business per month for DA calls but no long distance DA allowance. This is backwards, logically there should be a greater DA allowance for long distance calls since a directory for the distant calling area is not normally available to the caller;

(4) While SCB has not provided the average monthly amount of new number listings by month, it only provided the activity for October 1994 during which 67,889 in new number listings were issued. If this is representative of a normal month, an average of approximately 600,000 numbers are not available during the directory publishing cycle. This recognizes that there is a sixty to ninety day lag in the time a number list is compiled and the date when a directory is issued for a particular year. The directory does not include the new number listings during the lag time or for future new number listings until a new directory is published the following year. As a result, there is a significant number of listings which are not available in the directories and the ratepayer has no option but to use DA;

(5) SCB is attempting to take advantage of or circumventing the proposed local competition rule currently pending. Under the

proposed rule, SCB would be required to reduce access charges half way to the interstate level without offsetting rate increases. By using the DA charge to more than offset the access reductions, SCB avoids the earnings reductions required in the proposed local competition rule. This filing is also an attempt by SCB to stifle potential competition at the expense of the captive monopoly ratepayers by increasing the charges for monopoly directory assistance charges and reducing rates for the potentially competitive access charges;

(6) There is a general vagueness in the determination of who the "handicapped or disabled" are and who makes that determination to qualify for an exemption from this tariff filing;

(7) Additionally, SCB's recent tariff filing revision filed November 14, 1994, includes a fifty call allowance for "qualified handicapped or disabled" employees of businesses. The Company has provided nothing to show an allowance is adequate. Obviously, the imposition of such a charge on business will impact a business' decision when considering the employment of a disabled person who must obtain telephone numbers in the performance of their jobs. The allowance of approximately 2 calls per work day may not be sufficient especially when the position calls for extensive use of the telephone;

(8) There are illiteracy concerns for those citizens who cannot read

and would be disadvantaged by this tariff filing. While we recognize that it is not the duty of the telephone company to teach reading, it must be recognized that a large number of Tennesseans are functionally illiterate. Based on data obtained from the Tennessee Department of Education, approximately 1 in 6 Tennesseans is functionally illiterate. This indicates that approximately 816,000 are functionally illiterate based upon the U.S. Census Bureau estimate of the population of Tennessee;

(9) SCB's rationale for determining the proposed reductions in access and toll rates, and the amounts per service to be reduced by SCB is questionable as to its propriety. It may be more appropriate to reduce Caller ID or reduce touch-tone calling rates. SCB has not shown any linkage between its revenues for long distance and directory assistance rates;

(10) There is no assurance that 100% of the proposed access reductions by SCB will be flowed through by the Inter-exchange Carriers (IXCs) to the ratepayer. There are no new reductions in tariff filings pending for any long distance carrier. In other words, the earnings of the IXCs would increase if the access reductions are not flowed through dollar for dollar by reduced interlata long distance rates;

(11) Uncertainty exists as to whether the filing would jeopardize the

accuracy of the annual access reduction ordered by the Commission (Megacom Order U-87-7492). The filing made by the Company to reduce access rates in accordance with order U-87-7492 is under the assumption that the proposed tariff is already in effect. This assumption impacts the magnitude of the access reductions;

(12) Privacy concerns also exist in that SCB will release name and address to a DA caller seeking identification for a phone number. Presently, SCB's DA will not provide the name and address when the caller has only the telephone number. Under the proposed tariff a caller will be able to obtain such information. In addition, this proposal raises safety issues as well as privacy concerns;

(13) SCB should realize a dramatic increase in revenues from unpublished number listings if the tariff is approved. This increase is not recognized anywhere in the filing. Additionally, the tariff filing is a disincentive to timely updates of directories. Also, SCB has not quantified the expected revenue increase and earnings from this new service;

(14) SCB has failed to provide evidence to demonstrate the reasonableness and fairness of this tariff filing when it is presently recovering the cost of DA through other revenue streams. This Commission has historically denied SCB's filings for a per call charge for DA, as recent as September 1993 in tariff filing 92-190. SCB has

provided NO evidence since September 1993 to change the Commission's current policy DA service in Tennessee.

Q. Are there other concerns with SCB's tariff filing?

A. Yes, the CA requests that public hearings be held across SCB's Tennessee service area to allow SCB customers the opportunity to express an opinion as to whether customers should be charged on a per DA call basis or that DA be recovered on a business as usual basis. The hearings should be scheduled to allow a representative number of customers of all types, areas and means to express their views on the proposed DA filing. Additionally, the public should be adequately notified of their opportunity and the potential change in the ratepayers bill. After public opinion is expressed, the Commission can more adequately determine the reasonableness of the current DA tariff filing.

SCB has not stated how the safety, efficiency, or adequacy of DA relates to those rates. Moreover, the CA is concerned that the DA rate request is priced to operate contrary to a free market system by discouraging calls rather than establishing a low rate and encouraging calls.

It must also be recognized that while this tariff was made by SCB, it will impact all Tennessee ratepayers. If approved, it will be a precedent for filings by other carriers such as AT&T.

Q. Does this conclude your testimony?

A. Not necessarily. As I indicated earlier SCB was not fully responsive to our data request. We may have additional concerns upon receipt of that information.

CERTIFICATE OF SERVICE

I, L. Vincent Williams, hereby certify that a true and correct copy of the foregoing Testimony of Terry Buckner has been served on the following parties of record by depositing a copy of the same in the United States mail, postage pre-paid, addressed to them, in accordance with the following list, this 18th day of November, 1994:

Charles Howorth, Esq.
South Central Bell Telephone Company
333 Commerce St.
Suite 2101
Nashville, TN 37201-3300

John M. Farris, Esq.
50 North Front St.
Suite 1400
Memphis, TN 38103

Roger Briney, Esq.
AT&T
1200 Peachtree St., NE
Room 4068
Atlanta, GA 30309

Val Sanford, Esq.
230 4th Ave., North
3rd Fl.P.O. Box 198888
Nashville, TN 37219-8888

for L. Vincent Williams

STATE OF GEORGIA

COUNTY OF FULTON

BEFORE ME, the undersigned authority, duly commissioned and qualified in and for the State and County aforesaid, personally came and appeared James K. Brinkley who, being by me first duly sworn deposed and said that:

He is appearing as a witness on behalf of BellSouth Telecommunications, Inc., d/b/a South Central Bell Telephone Company, before the Tennessee Public Service Commission in Docket No. 94-02876, Application of South Central Bell to Establish Regulation, Rates and Charges for the Provision of Directory Assistance Service in Tennessee, and if present before the Commission and duly sworn, his testimony would be set forth in the annexed Testimony consisting of 8 pages and 0 exhibits.

James K. Brinkley

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 11th DAY OF NOVEMBER, 1994.

Martha E. McDougal
Notary Public

Notary Public, Gwinnett County, Georgia
My Commission Expires March 8, 1997

DIRECT TESTIMONY OF
JAMES K. BRINKLEY
ON BEHALF OF BELLSOUTH TELECOMMUNICATIONS, INC.,
D/B/A
SOUTH CENTRAL BELL TELEPHONE COMPANY

NOVEMBER 18, 1994

Q. PLEASE STATE YOUR NAME, EMPLOYER, POSITION AND BUSINESS ADDRESS.

A. My name is James K. Brinkley. I am employed by BellSouth Telecommunications, Inc., d/b/a South Central Bell Telephone Company in Tennessee (hereinafter referred to as "South Central Bell" or "the Company"). My present position is Director - Pricing & Economics in the Regulatory and External Affairs department. My business address is 675 West Peachtree Street NE, Atlanta, Georgia 30375.

Q. PLEASE GIVE A BRIEF DESCRIPTION OF YOUR BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Science degree from Clemson University in 1969 and a Master of Engineering degree from the University of South Carolina in 1973. After graduating from Clemson University, I served approximately two years active duty in the U.S. Army and am presently a Battalion Commander in the U.S. Army Reserves. I began my telephone

career with Southern Bell in 1973 in Columbia, South Carolina as an Outside Plant Engineer. Since then, I have served in various positions in the Engineering, Support Services, Marketing, and Pricing organizations in both South Carolina and Georgia. Currently, I have responsibilities for tariff and rate development for switched access, operator services, and billing and collections services for the nine states in the BellSouth region.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On October 6, 1994, South Central Bell filed a revenue neutral tariff package to implement a charge for Directory Assistance (hereinafter referred to as "DA"). My testimony will describe the elements of the Company's filing package, why it is appropriate to charge for DA, and the benefits to consumers that will occur with approval of this package by the Tennessee Public Service Commission.

Q. DESCRIBE THE TARIFF PACKAGE FILED BY SOUTH CENTRAL BELL.

A. There are three parts to this tariff filing:

1. The implementation of a charge for DA service,
2. A reduction of Message Telecommunications Service ("MTS") charges, and
3. A reduction of intrastate Switched Access charges.

The revenue generated by a DA charge will be passed on to customers through lower long distance rates and access charges. Specifically, the DA charge proposal will generate approximately ~~$19.9~~ 22.9 million in revenue and cost savings annually. The MTS charge proposal will reduce revenues by approximately ~~$6.6~~ 7.7 million annually. The Switched Access charge proposal will reduce revenues by approximately ~~$13.3~~ 15.2 million annually.

It should be noted that the impact of the Switched Access charge reduction on Tennessee consumers will depend on the pricing actions of the interexchange carriers ("IXCs").

Q. DID SOUTH CENTRAL BELL INITIATE THIS PROCEEDING TO ADJUST ITS EARNINGS?

A. No. As I have explained above, if this filing is approved, it will be revenue neutral and thus will have no effect on the company's earnings.

Q. WHAT WILL SOUTH CENTRAL BELL CHARGE FOR DIRECTORY ASSISTANCE?

A. The proposed tariff provides that all residence customers will have an allowance of five free DA calls per line per month and business customers will receive a three call

allowance per line or equivalent per month. A charge of $.25 per call will be applied on DA calls exceeding the allowance. There will be no charge for DA calls made from hospitals, nursing homes, public and semi-public telephone service locations and customer-provided public telephones. Customers with disabilities that prevent their use of the printed directory will be exempt from the charges on their residential line and will receive a fifty call allowance on their business line.

South Central Bell's proposal protects those customers who use DA service only when necessary by moving some of the responsibility for paying for the service to those who use the service frequently. While the frequent DA user will begin paying for this service, all customers will have access to lower toll rates.

Q. WHY IS IT APPROPRIATE TO CHARGE FOR DIRECTORY ASSISTANCE?

A. In an increasingly competitive telecommunications environment, prices for individual services should reflect their underlying cost. Currently, competitive applications of Time Warner AxS of Tennessee, L.P., AVR, L.P., d/b/a Hyperion of Tennessee; Access Transmission Service, Inc. ("ATS"), Teleport Denver Inc., and Metropolitan Fiber Systems of Tennessee, Inc. ("MFS") are pending before the Commission,

and a rulemaking is underway to open the local exchange to competition. Tariffs such as this one which move rates toward reflecting their underlying cost must be implemented in order to transition customers in Tennessee to a rate structure which will be sustainable in this increasingly competitive environment.

Today, because there is no charge for DA service in Tennessee, over $27 million of this service cost is recovered each year through prices customers pay for other services. Almost every customer, therefore, pays for DA service whether they use the service or not. Tennessee is the only state in the nation where there is no charge for customers to use intrastate DA service. Present usage studies show that eighty percent of residential customers make five or fewer DA calls, and ninety-five percent of business customers make three or fewer DA calls. From our studies, the majority of Tennessee's customers will not even be affected by the DA charge proposed in the tariff.

Q. IF THIS TARIFF IS APPROVED, WILL SOUTH CENTRAL BELL LAY OFF OPERATORS WHEN THERE IS LESS DEMAND FOR THE SERVICE?

A. The Company does not expect any layoffs as a result of implementing a directory assistance charge and has made this commitment to the Communications Workers of America. Any

necessary reduction in force will be handled by attrition and reassignment.

Q. DESCRIBE THE TOLL CHARGE REDUCTION PROPOSED IN THE TARIFF.

A. There are two parts to the toll reduction proposed in the tariff. First, the tariff proposes to lower the rate on all mileage bands 31 miles and over. This reduction equates to $2,770,292 annually. The second part of this tariff filing is a volume discount which equates to a ~~$3,803,000~~ $4,724,000 revenue reduction.

The volume discount will apply to both residential and business customers. For each billing period, customers billed up to $10 in intraLATA toll will receive a one percent discount, for ~~$10.01~~ to $25 - a ~~five~~ 5 1/2 percent discount, and for more than $25 - an ~~eight~~ 11% percent discount. The discounts will be applied on an account basis for calls carried by South Central Bell and are in addition to rate period discounts. The discounts will not apply to Optional Calling Plan calls, local exchange service charges, DA charges, operator-handled surcharges, or RegionServ calls. This volume discount will provide a benefit to those customers who rely on long distance service.

Q. DESCRIBE THE SWITCHED ACCESS CHARGE REDUCTION PROPOSED IN THE

TARIFF.

A. The annual projected gross revenue impact for Switched Access services is a reduction of $15,738,867 to South Central Bell. The projected net revenue impact, assuming flow through of the access rate decreases by the IXCs, is a reduction of $13,300,000. This reduction equals approximately half of the amount necessary to attain parity with current interstate Switched Access rates in Tennessee. Additionally, this reduction equates to approximately a twenty percent change in the composite Switched Access rate.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. South Central Bell's tariff filing will result in a much greater benefit to customers than does free DA. Present usage studies show that eighty percent of residential customers make five or fewer DA calls, and ninety-five percent of business customers make three or fewer DA calls. From our studies, the majority of Tennessee's customers will not even be affected by the DA charge proposed in the tariff.

There are many customer benefits to be gained from implementation of South Central Bell's proposed tariff:

* responsibility for paying for DA service shifted to the

individuals and businesses who use it frequently (i.e., move prices toward reflecting their underlying cost);

* lower MTS rates for the longer mileage bands;

* a volume discount for customers who use South Central Bell's intralata long distance service and, by choice or necessity, use long distance services frequently; and

* a reduction in the difference between intrastate and interstate access rates in Tennessee by approximately half.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF TENNESSEE

Office of the Attorney General

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EXEC[illegible]ETARY

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ATTORNEY GENERAL AND REPORTER

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April 30, 1999

Mr David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: United Telephone-Southeast, Inc. Tariff to Reflect Proposed Changes Under Price Regulation Plan
Docket No. 98-00626

Dear Mr. Waddell:

I have enclosed an original and thirteen copies of Direct Testimony of Consumer Advocate Division witness Robert T. Buckner, Senior Regulatory Analyst in the above referenced matter. Copies are being furnished to counsel of record for interested parties.

Sincerely,

L. Vincent Williams
Consumer Advocate

c: Counsel of record

#103500

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE: UNITED TELEPHONE-SOUTHEAST, INC. TARIFF TO REFLECT PROPOSED CHANGES UNDER PRICE REGULATION PLAN
DOCKET NO. 98-00626

****

DIRECT TESTIMONY
of
ROBERT T. BUCKNER

****

April 30, 1999

#103500

Q. Please state your name for the record.

A. My name is Robert T. Buckner ("Terry").

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. How long have you been employed in the utility industry?

A. Approximately twenty years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS") for eight years and the First Utility District of Knox County for three years.

Q. What is your educational background and what degrees do you hold?

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants. Additional

education background with respect to my qualifications is provided in Exhibit No. 1 (Attachment A).

Q. Would you briefly describe your responsibilities as a Regulatory Analyst since your employment with the CA?

A. I prepared testimony and exhibits as an employee with the Commission before becoming a member of the CA. My responsibilities have not changed significantly since becoming employed with the CA.

Q. What is the purpose of your testimony before the Tennessee Regulatory Authority ("TRA")?

A. The purpose of my testimony is to present the CA's recommendations on the calculated amount to be used in changing United Telephone-Southeast ("UTSE") Tariff under their Price Regulation Plan in Tennessee Regulatory Authority ("TRA") Docket #98-00626. Also, my testimony will address the methodology set forth in the stipulation in TRA Docket #96-01423 and its concurrence with Tenn. Code Ann. § 65-5-209.

Q. By what amount should UTSE be allowed to change their Tariff under the Price Regulation Plan?

A. It is the CA's position that UTSE should reduce their Non-Basic Rates by an annual amount of $351,935 in contrast to UTSE's proposal to increase rates $2,072,472 for a total difference of $2,457,406. See Attachment B, Line 10 of Exhibit No. 1. This amount is consistent with the CA's Statement of Issues filed with the TRA on December 1, 1998.

Q. Does this reduction include the imputation of Yellow Page revenues?

A. No. UTSE has refused to identify the Yellow Page revenue that would have been imputed had the procedures that were in place in 1995 were being followed today. Consequently, the impact of this alleged deficiency cannot be determined at this time.

Q. Does the methodology as set forth in the stipulation in TRA Docket #96-01423 conflict with the requirements of Tenn. Code Ann. § 65-5-209?

A. No. The methodology does not conflict. Tenn. Code Ann. § 65-5-209 establishes the limit in the amount of rates increases that may occur in any one year:

> **§ 65-5-209(e)** A price regulation plan shall maintain affordable basic and non-basic rates by **permitting a maximum annual adjustment that is capped at the lesser of one half (1/2) the percentage change in inflation for the United States using the gross domestic product-price index ("GDP-PI") from the preceding year as the measure of inflation, or the GDP-PI from the preceding year minus two (2) percentage points.** An incumbent local exchange telephone company may adjust its rates for basic local exchange telephone services or non-basic services only so long as its aggregate revenues for basic local exchange telephone services or non-basic services generated by such changes do not exceed the aggregate revenues generated by the maximum rates permitted by the price regulation plan. (Emphasis added.)

The stipulation establishes the method of determining the cumulative percentage increases and the maximum cumulative increase allowed over a period of years assuming that rates are increased the maximum allowed each year in accordance with Tenn. Code Ann. § 65-5-209. The stipulation does not modify the provisions of the statute and does not allow UTSE to increase rates in any one year more than the amount otherwise allowed under the statute. The maximum increase in any one year continues to be limited by the statute.

Additionally, the stipulation as interpreted by UTSE does conflict with the Telecommunications Act of 1996 and the FCC order

in Docket #96-128. Section 276(b)(1)(B) of the Telecommunications Act (See Attachment E) directs the FCC to "discontinue the intrastate and interstate carrier access charge payphone service elements and payments.... and all intrastate and interstate payphone subsidies from basic exchange and exchange access revenue...." In its Docket #96-128, the FCC ordered such subsidies to be removed. UTSE has notified the TRA that its intrastate rates included an estimated subsidy for payphone operations of $143,500. (See Attachment D.) UTSE reduced its access charges to remove the subsidy in April 1997. If the base rates in effect on June 6, 1995 are used in the computation of the SPI as proposed by UTSE, this subsidy is restored. Clearly, this is contrary to the FCC's Orders.

Q. Does the methodology as adopted in the stipulation create an additional limit that was not specifically identified in Tenn. Code Ann. § 65-5-209?

A. Yes, it could. If the mix in the type of services being provided were to change materially, the formula for establishing the maximum cumulative increase could prohibit a company from increasing rates in any one year to the full amount otherwise allowable under Tenn. Code Ann. § 65-5-209.

Attachment C to my testimony is an example of how the

stipulation could result in rates that are less than the maximum allowed under Tenn. Code Ann. § 65-5-209.

As shown on page 3 of the example, the adjustment allowed under Tenn. Code Ann. § 65-5-209 is a .8% reduction. The cumulative PRI as computed in accordance with the stipulation is 100.29%. However, when calculated using the rates that produce the .8% reduction the SPI is 101.23%. Since under the stipulation the SPI cannot exceed the PRI, the proposed rates that produce a .8% reduction would exceed those allowed under the stipulation. In this example, the rates allowed under the stipulation would be lower than those allowed by Tenn. Code Ann. § 65-5-209.

This does not indicate that the stipulated methodology is faulty. The parties simply agreed to a methodology that may result in some instances where rates are lower than the maximum allowed otherwise under the statute. As a result, the stipulation serves as the limiting factor. This does not indicate that there is a conflict between the statute and the stipulation since the resulting rates are lower than the maximum allowed by the statute. I have been advised by counsel that while the parties may agree on a procedure that imposes an additional limit on the level of rates, the parties cannot implement a procedure that results in rates greater than those allowed by statute.

Q. What caused the stipulation methodology to result in a lower rate level in the example?

A. The change in the mix of services. I point out that this is a hypothetical example that is being used for illustrative purposes and does not reflect an actual change in mix that has occurred.

Q. Does this conclude your testimony?

A. Yes, it does.

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE: UNITED TELEPHONE-SOUTHEAST, INC. TARIFF TO REFLECT PROPOSED CHANGES UNDER PRICE REGULATION PLAN

DOCKET NO. 98-00626

****

EXHIBITS

****

April 30, 1999

#103500

Attachment A

Robert T. Buckner (Terry)

Senior Regulatory Analyst

Office of the Attorney General for the State of Tennessee

Consumer Advocate Division

Additional Education Background:

Micro-Computer Training, **University of Wisconsin, Madison**

Cost Separations School, **United States Telephone Association, San Diego**

Rate Case School, **Arthur Andersen LLP, Chicago**

Telecommunications Conference, **University of Georgia, Athens**

NARUC Conference, **Michigan State University, Lansing**

Management Training Seminar, **Vanderbilt University**

Interstate Access Settlements, **National Exchange Carrier Association**

SEARUC Conferences, **Birmingham, AL. and Charleston, S.C.**

Telephone Plant Accounting Program, **Ernst and Young LLP, Atlanta**

ATTACHMENT B

Sprint United Telephone-Southeast, Inc
1998 Annual Price Adjustment Filing

Line	Aggregate Non-Basic Revenues at Current Rates	Aggregate Non-Basic Revenues @ 6/98 Rates		
1	General Subscriber Service Tariff	$30,697,976 40	a/	
2	Access	9,103,137 60	b/	
3	Directory Revenue	58,353 60	c/	
4	Miscellaneous Revenues	4,132,349 88	d/	
5	Total Non-Basic per Company [L1+L2+L3+L4]			$43,991,817 48
	Computation of the Maximum Adjustment Factor			
6	Inflation First QTR 1997 vs First Qtr 1998	1 20%	e/	
7	Maximum Annual Adjustment Factor is the lesser of 1/2 Inflation Rate [L6 X 5]	0 60%		
	or			
8	Inflation less 2% [L6-2%]	-0 80%		
9	Maximum Adjustment Factor [L8]			-0 80% f/
10	Maximum Allowed Annual Adjustment to Aggregate Non-Basic Revenue [L5 X L9]			($351,934 54)
	Aggregate Non-Basic Revenues Proposed Rates	**Aggregate Non-Basic Revenues @ UTSE Proposed Rates**		
11	General Subscriber Service Tariff	$32,755,722 24	a/	
12	Access	9,120,864 00	b/	
13	Directory Revenue	58,353 60	c/	
14	Miscellaneous Revenues	4,132,349 88	d/	
15	Total Company Proposed Non-Basic Revenue [L11+L12+L13+L14]	$46,067,289 72		
16	UTSE Proposed Increase in Aggregate Non-Basic Revenues [L15-L5]			$2,075,472 24
17	Proposed Increase in Aggregate Non-Basic Revenues Exceeds Allowed Adjustment [L16-L10]			$2,427,406 78
18	UTSE Proposed % Increase in 1998 Non-Basic Aggregate Revenues	4 72%		

a/ Sprint UTSE Filing as revised 10/16/98 Non-Basic Service Price out page 12
b/ Sprint UTSE Filing as revised 10/16/98 Non-Basic Service (Access)Price out page 2
c/ Sprint UTSE Filing as revised 10/16/98 Non-Basic Service General Ledger [Directory compensation] page 1
d/ Sprint UTSE Filing as revised 10/16/98 Non-Basic Service General Ledger [Miscellaneous] page 1
e/ ATTACHMENT B of Sprint UTSE's Filing as revised 10/16/98
f/ Tenn Code Ann 65-5-209

Hypothetical Example

Proposed changes for each of the three years fall under the maximum annual increase allowed under Tenn Code Ann. 65-5-209. However in the third year the proposed rates exceed the maximum level established by the Stipulation accepted in 1996.

Assumptions:	Year 1	Year 2	Year 3
Inflation (GDP-PI)	2 40%	2.70%	1 20%
Maximum Factor [Lesser of (1/2)X(GPI-PI) or(GDP-2%)]	0 40%	0.70%	-0.80%
Year 1 - rate reduction			
Year 2 - No rate change			
Year 3- Rate reduced inaccordance with Tenn. Code Ann 65-5-209			
Computed Results			
Computed Annual Increase	-1.00%	0 00%	-0.80%
Computed PRI per Stipulation	100 40%	101 10%	100.29%
Computed SPI per Stipulation	99 00%	99 00%	101.23%
SPI Exceeds the Cumulative PRI by			0.93%

Year 1
Comparison of SPI, PRI, and Annual Increase

	Base/Current Rates			Proposed Rate			
		Initial			Proposed		
Service	Volume	Rates	Revenue	Volume	Rates	Revenue	
Service 1	1,000	$1 000	$1,000 00	1,000	$0 9900	$990.00	
Service 2	4,000	2 0000	8,000.00	4,000	$1 9800	7,920.00	
Service 3	200	5 0000	1,000.00	200	$4 9500	990.00	
Service 4	600	7 0000	4,200.00	600	$6.9300	4,158.00	
Service 5	800	3.0000	2,400.00	800	$2 9700	2,376.00	
Service 6	900	4 0000	3,600.00	900	$3 9600	3,564.00	
			$20,200 00	Aggregate Revenue		$19,998 00	99 00% SPI
				PRI			100 40% PRI
				Annual % Change			-1.00%
				Cumulative Change			-1.00%

Year 1 proposed rate changes comply with both Tenn Code Ann 65-5-209 and the Stipulation

Hypothetical Example
Year 2

Comparison of proposed increase with annual limit per statute.

	Current Rates			Proposed Rate			
Service	Current Volumes	Current Rates	Revenue	Proposed Volume	Proposed Rates	Revenue	
Service 1	1,100	$0 9900	$1,089 00	1,100	$1.2500	$1,375 00	
Service 2	4,500	1 9800	8,910 00	4,500	2.2500	10,125 00	
Service 3	300	4 9500	1,485.00	300	4.9500	1,485.00	
Service 4	650	6 9300	4,504.50	650	6 9300	4,504.50	
Service 5	850	2 9700	2,524.50	850	2 9700	2,524.50	
Service 6	1,000	3 9600	3,960.00	1,000	2 4590	2,459 00	
Aggregate Revenues			$22,473.00	Aggregate Revenues		$22,473 00	100.00%
				Allowed annual Increase			0 70%
				Annual % Change			0 00%

Comparison of PRI with SPI.

	Base Rates			Proposed Rate			
Service	Current Volumes	Initial Rates	Revenue	Proposed Volume	Proposed Rates	Revenue	
Service 1	1,100	$1 0000	$1,100.00	1,100	$1.2500	$1,375 00	
Service 2	4,500	2 0000	9,000 00	4,500	2 2500	10,125 00	
Service 3	300	5 0000	1,500.00	300	4.9500	1,485 00	
Service 4	650	7 0000	4,550 00	650	6.9300	4,504 50	
Service 5	850	3 0000	2,550.00	850	2.9700	2,524.50	
Service 6	1,000	4 0000	4,000 00	1,000	2 4590	2,459 00	
Aggregate Revenues			$22,700.00	Aggregate Revenues		$22,473.00	99.0000% =SPI
				Cumulaltive % Change			-1 00%
							101.10% =PRI
				Allowed Cumulative % Change			1 10%

Year 2 proposed rate changes comply with both Tenn Code Ann 65-5-209 and the 1996 Stipulation

Hypothetical Example
Year 3

Comparison of proposed increase with annual limit per statute.

	Current Rates			Proposed Rate			
Service	Current Volumes	Current Rates	Revenue	Volume	Proposed Rates	Revenue	
Service 1	3,100	$1.2500	$3,875.00	3,100	$1 5000	$4,650 00	
Service 2	5,000	$2 2500	11,250.00	5,000	$2 3000	11,500.00	
Service 3	450	$4 9500	2,227.50	450	$4 9000	2,205.00	
Service 4	700	$6 9300	4,851.00	700	$6 9300	4,851 00	
Service 5	860	$2.9700	2,554 20	860	$2.9000	2,494 00	
Service 6	900	$2 4590	2,213.10	900	$1.1720	1,054 80	
Aggregate Revenues			$26,970.80	Aggregate Revenues		$26,754 80	99 20%
				Allowed annual Increase			-0 80%
				Annual % Change			-0 80%

Comparison of PRI with SPI.

	Base Rates			Proposed Rate			
Service	Current Volumes	Initial Rates	Revenue	Volume	Proposed Rates	Revenue	
Service 1	3,100	$1 0000	$3,100.00	3,100	$1.5000	$4,650 00	
Service 2	5,000	$2 0000	10,000 00	5,000	$2.3000	11,500.00	
Service 3	450	$5 0000	2,250 00	450	$4.9000	2,205.00	
Service 4	700	$7 0000	4,900.00	700	$6.9300	4,851.00	
Service 5	860	$3 0000	2,580.00	860	$2.9000	2,494.00	
Service 6	900	$4.0000	3,600.00	900	$1.1720	1,054.80	
Aggregate Revenues			$26,430.00	Aggregate Revenues		$26,754 80	**101.23%** =SPI
				Cumulaltive % Change			1.23%
				PRI			**100.29%** PRI
				Allowed Cumulative % Change			0 29%

Year 3 rate changes comply with the limit in Tenn. Code Ann. 65-5-209 but exceed the limit established by the 1996 Stipulation.

Computation of Cumulative Adjustment Limit

	First Qtr. 1995 vs First Qtr 1996	First Qtr. 1996 vs First Qtr 1997	First Qtr. 1997 vs First Qtr 1998
Inflation (GPI-PI)	2 40%	2.70%	1.20%
Calculation			
Step 1			
Base Rate of 100	100.00%	100.00%	100.00%
Step 2			
Plus: The lessor of			
1/2 Inflation Rate	1.20%	1 35%	0 60%
or			
Inflation Rate - 2%	0 40%	0 70%	-0.80%
Annual Adjustment Factor Tenn Code Ann. 65-5-209	0 40%	0 70%	-0 80%
	100 40%	100 70%	99.20%
Step 3			
Divided by 100%	1 004	1.007	0 992
Step 4			
Current PRI	100 00%	100 40%	101 10%
New PRI=Current PRI X Annual Adjustment Factor	100 4000%	101.1028%	100 2940%

Attachment D

May 27, 1997

MEMORANDUM

TO: Lynn Greer, Chairman
Sara Kyle, Director
Melvin Malone, Director

FROM: Chris Klein, Chief Utility Rate Division
Mike Gaines, Telecommunications Manager

SUBJECT: Tariff filing by United Telephone Southeast (UTSE) to reduce the intrastate CCLC access rate to remove the subsidy to pay telephones. Tariff 97-206, Docket 97-00409

UTSE filed tariffs effective April 1, 1997, to remove payphone operations from its tariffs. At that time, UTSE estimated the subsidy to payphone operations to be immaterial and did not reduce rates. However, on May 19, 1997, UTSE submitted a revised subsidy estimate and filed this tariff to reduce access rates $143,500, effective the same day.

The Staff reviewed this estimated amount, but has not audited the number because this matter will be addressed in the pending Payphone Docket 97-00409. Unless otherwise notified, this tariff will go into effect pending the outcome of Docket 97-00409.

cc: Docket File 97-00409

Attachment E

Telecommunications Act of 1996 Section 276

"SEC. 276. PROVISION OF PAYPHONE SERVICE.

"(a) NONDISCRIMINATION SAFEGUARDS.--After the effective date of the rules prescribed pursuant to subsection (b), any Bell operating company that provides payphone service--

"(1) shall not subsidize its payphone service directly or indirectly from its telephone exchange service operations or its exchange access operations; and

"(2) shall not prefer or discriminate in favor of its payphone service.

"(b) REGULATIONS.--

"(1) CONTENTS OF REGULATIONS.--In order to promote competition among payphone service providers and promote the widespread deployment of payphone services to the benefit of the general public, within 9 months after the date of enactment of the Telecommunications Act of 1996, the Commission shall take all actions necessary (including any reconsideration) to prescribe regulations that--

"(A) establish a per call compensation plan to ensure that all payphone service providers are fairly compensated for each and every completed intrastate and interstate call using their payphone, except that emergency calls and telecommunications relay service calls for hearing disabled individuals shall not be subject to such compensation;

"(B) discontinue the intrastate and interstate carrier access charge payphone service elements and payments in effect on such date of enactment, and all intrastate and interstate payphone subsidies from basic exchange and exchange access revenues, in favor of a compensation plan as specified in subparagraph (A); (Emphasis Added)

"(C) prescribe a set of nonstructural safeguards for Bell operating company payphone service to implement the provisions of paragraphs (1) and (2) of subsection (a), which safeguards shall, at a minimum, include the nonstructural safeguards equal to those adopted in the Computer Inquiry-III (CC Docket No. 90-623) proceeding;

"(D) provide for Bell operating company payphone service providers to have the same right that independent payphone providers have to negotiate with the location provider on the location provider's selecting and contracting with, and, subject to the terms of any agreement with the location provider, to select and contract with, the carriers that carry interLATA calls from their payphones, unless the Commission determines in the rulemaking pursuant to this section that it is not in the public interest; and

"(E) provide for all payphone service providers to have the right to negotiate with the location provider on the location provider's selecting and contracting with, and, subject to the terms of any agreement with the location provider, to select and contract with, the carriers that carry intraLATA calls from their payphones.

"(2) PUBLIC INTEREST TELEPHONES.--In the rulemaking conducted pursuant to paragraph (1), the Commission shall determine whether public interest payphones, which are provided in the interest of public health, safety, and welfare, in locations where there would otherwise not be a payphone, should be maintained, and if so, ensure that such public interest payphones are supported fairly and equitably

"(3) EXISTING CONTRACTS.--Nothing in this section shall affect any existing contracts

between location providers and payphone service providers or interLATA or intraLATA carriers that are in force and effect as of the date of enactment of the Telecommunications Act of 1996

"(c) STATE PREEMPTION.--To the extent that any State requirements are inconsistent with the Commission's regulations, the Commission's regulations on such matters shall preempt such State requirements.

"(d) DEFINITION --As used in this section, the term 'payphone service' means the provision of public or semi-public pay telephones, the provision of inmate telephone service in correctional institutions, and any ancillary services.".

BEFORE THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE: UNITED TELEPHONE-SOUTHEAST, INC TARIFF TO REFLECT PROPOSED CHANGES UNDER PRICE REGULATION PLAN	)	DOCKET NO. 98-00626

AFFIDAVIT

I, Robert T Buckner, Senior Regulatory Analyst for the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above referenced case and the opinion of the Consumer Advocate Division

Terry Buckner

Sworn to and subscribed before me
this 13th day of April, 1999.

Teresa G. Harris
NOTARY PUBLIC

My commission expires on. Jan. 25, 2003

#103500

CERTIFICATE OF SERVICE

I hereby certify that this document was served on parties of record by U.S. Mail or by facsimile this 30th day of April, 1999.

James B. Wright, Esq.
United Telephone-Southeast, Inc
14111 Capital Blvd.
Wake Forest, NC 27587-5900

L. Vincent Williams

#103500

STATE OF TENNESSEE

Office of the Attorney General

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July 30, 1999

Mr David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Proceeding for the Purpose of Addressing Competitive Effects of Contract Service Arrangements Filed by BellSouth Telecommunications, Inc. in Tennessee
Docket No. 98-00559

Dear Mr. Waddell:

I have enclosed an original and thirteen copies of Rebuttal Testimony of Consumer Advocate Division witness Robert T. Buckner, Senior Regulatory Analyst, in the above referenced matter Copies are being furnished to counsel of record for interested parties.

Sincerely,

L. Vincent Williams
Consumer Advocate

c: Counsel of record

15999

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE: PROCEEDING FOR THE PURPOSE OF ADDRESSING COMPETITIVE EFFECTS OF CONTRACT SERVICE ARRANGEMENTS FILED BY BELLSOUTH TELECOMMUNICATIONS, INC. IN TENNESSEE
DOCKET NO. 98-00559

****

REBUTTAL TESTIMONY
of
ROBERT T. BUCKNER

****

July 30, 1999

Q. Please state your name for the record.

A. My name is Robert T.("Terry") Buckner.

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. How long have you been employed in the utility industry?

A. Approximately twenty years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS Telecom") for eight years and the First Utility District of Knox County for three years.

Q. What is your educational background and what degrees do you hold?

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Certified Public Accountant, a member of the Tennessee Society of Certified Accountants, and a member of the American Institute of

Certified Public Accountants. Additional education background with respect to my qualifications is provided in Exhibit RTB-1.

Q. Would you briefly describe your responsibilities as a Senior Regulatory Analyst since your employment with the CA?

A. Before becoming a member of the CA, I prepared testimony and financial exhibits as an employee with the Commission. Since becoming employed with the CA, my responsibilities have not changed significantly.

Q. What is the purpose of your testimony before the Tennessee Regulatory Authority ("TRA")?

A. The purpose of my testimony is to present factual information, which supports the CA's position concerning the two Contract Service Arrangements ("CSAs") initiated by BellSouth ("Bell") in TRA Dockets #99-00210 and #99-00244, CSA's TN98-2766-00 and KY98-4958-00 respectively, and to respond to the positions taken by Bell's witness Frame.

Q. Have you done any other analysis of Bell's CSAs than the work specifically related to these two CSAs?

A. Yes. In Docket #97-01105, I reviewed many of Bell's CSAs

that had been filed for period of time in 1997. I set forth the results of my review in a document filed in that docket entitled, *Consumer Advocate Division's Comments on BellSouth's Contract Service Arrangements*, July 22, 1998. At this time, I wish to adopt my opinion as set forth in that document as part of my testimony in the present Dockets. A copy of the Comments on BellSouth's Contract Service Arrangements is attached as Exhibit RTB-2.

Q. In your investigation of Docket #97-01105, what was Bell's apparent motive for CSAs?

A. I met with representatives of Bell on February 18, 1998 to discuss the matter of CSAs. I concluded from our discussions that it was Bell's position that there were three basic reasons for the CSAs: (1) Response to a competitive telecommunications provider; (2) To protect Bell's revenue stream for the long-term; and (3) As an incentive for customers to increase the usage of services.

Q. In the meeting of February 18, 1998, what was the basis for determining discount levels?

A. The basis for determining the discount levels was the following: (1) Up to the individual marketer; (2) There was no specific Bell policy for determination; and (3) The discount amount was dependent

upon the volume of services purchased by the customer.

Q. How is the information gained in Docket #97-01105 relevant to these Dockets?

A. I believe that the information is relevant in that it is indicative of the fluid and evolving nature of the CSAs in Tennessee. Additionally, there is evidence of anti-competitive behavior and price discrimination.

Q. In these Dockets, the Bell witness, Mr. Frame, defends the CSAs primarily on the basis of competition. (See Frame Direct Testimony, Page 2, Lines 19-21.) Has the TRA, the FCC, or any other authority found that Bell has complied with the requirements necessary to open its local market in Tennessee to competition?

A. No. The Telecommunications Act of 1996 requires incumbents such as Bell to take action to allow competition to develop in the local market. Those requirements are found in Sections 251 and 252 of the Act. In Section 271(B), a checklist is provided for determining if an incumbent Regional Bell Operating Company ("RBOC"), such as Bell, has complied with Sections 251 and 252. Neither the TRA, the FCC, nor any other appropriate authority has found that Bell has yet

complied with the requirements of the Act in Tennessee.

In May 1998, the TRA conducted an extensive hearing of more than ten days in Docket #97-00309 for the purpose of determining if Bell had opened its local market in Tennessee to competition in accordance with the Act and as required to be eligible to enter the regional interLATA long distance market. On April 8, 1999, Bell filed a Notice of Voluntary Dismissal and Withdrawal in Docket #97-00309 volunteering to withdraw its request that the TRA find that it had opened its market to allow competition as required by the Telecommunications Act of 1996. Since April 8, 1999, Bell has not filed or otherwise provided persuasive evidence that it has opened its local Tennessee market to competition.

Q. Have you reviewed the "Rate Assurance" provisions included in the CSA identified by Bell as CSA TN-98-2766-00?

A. Yes, on page 9 of the CSA TN98-2766-00 in Docket #99-00210, the following provision is found:

> If _____ is offered a service proposal from an unauthorized carrier that is comparable both in rate and in level of support provided by BellSouth for any V&T Eligible Service which priced at least 15% less than those provided to _____ by BellSouth which priced at least 15% less than those provided to _____ by BellSouth then these services may be considered for a price reduction. _____shall provide

BellSouth written notice of the service proposal, and sufficient information to validate the terms and rates of the offer and the option to respond to the alternative proposal.

BellSouth shall respond in writing within seven (7) calendar days as to whether or not BellSouth will pursue a new rate for _____. In the event BellSouth elects to respond to the offering from the alternative carrier and offers _____ a service proposal with rates that are within ten percent (10%) of the alternative carrier's competitive offering, this agreement shall continue in effect at the new customized rate and charges until the expiration of the V&T Agreement. The parties shall amend the Minimum Annual Revenue Base and the corresponding Discount Levels listed in Appendix II to reflect the rate reduction and any other portions of the Agreement necessary to effect this Rate Assurance Adjustment

If BellSouth elects not to respond to the offer from the alternative carrier or does not offer _____ a service proposal with rates that are within ten percent (10%) of the alternative carrier's offering, the parties shall amend Appendix IA, Appendix IB and Appendix II and any other pertinent provisions of this Agreement as necessary to reduce _____'s Minimum Annual Revenue Base, the Annual Revenue Base and the corresponding Discount Levels listed in Appendix II, if necessary, to permit _____ to purchase the services in question from the alternative carrier.

While this provision is labeled "Rate Assurance," the assurance provided is that Bell will be able to stop a customer from moving to a competitor of Bell. This provision does not assure the customer that

Bell will match a competitor's offer. Instead, it tends to guarantee that Bell can retain the customer by offering to provide the service at rates that are 10% higher than the rates offered by the competitor. While the customer could theoretically reject the higher Bell rates, the punitive effect of the termination penalty included in the CSA would likely result in any potential saving being captured by Bell and not by the customer.

Q. What amount of a discount would a competitor have to offer the customer under this CSA before Bell would need to respond?

A. Under this provision, a competitor would have to offer the customer a rate that is 23.5% below Bell's Tariffed rate before Bell would even have to consider responding.

As stated, the prices offered by the competitor must be priced at least 15% less than those provided by Bell under the contract. Since the CSA provides a discount of 10%, the prices under the CSA are at 90% of the tariffed rates for the services provided. A 15% reduction in these rates would require the offered rates to be equal to 76.5% of the tariffed rates. (90% X 85%= 76.5%) This, of course, reflects a 23.5% discount.

Bell CSA provided Discount off Tariffed Rates	10%
Bells' Rates as % of Tariffed	90%
The required competitive offer must be 15% below Bell	90% X 85%=76 5% of Tariffed Rates
Total minimum discounts offered by the Competitor	100% - 76 5%=**23.5%**

Q. What level of a discount would Bell have to include in its counter offer in order to invoke the termination penalty if the customer elects to purchase service from the competitor?

A. Since Bell needs only to come within 10% of the competitor in order to bind the customer, Bell is only required to increase its contract discount from 10% to 15.85%.

A competitor offers a 23 5% discount off Bell Tariffed Rates Competitors' rates as a percent of Tariffed	76 5%
Bells' response must be within 10% of Competitive offer	79 5% X 110%=84 15%
Discount Required by Bell to retain the customer	100%-84 15%=**15.85%**

As a result, the customer would not be able to take advantage of what might otherwise be deemed a more economic and competitive offer, but instead will be bound to Bell.

While the customer could theoretically reject the Bell counter offer of the 15.85% discount, the punitive termination provision would

likely eliminate any savings.

How the termination provision would penalize the customer depends on when the contract terminates. As Mr. Frame stated in his pre-filed testimony, termination of the contract at the end of a contract year results in a flat charge. (See Frame Direct Testimony, Page 18, Lines 6-8.) However, if the contract is terminated during a contact year, the charge is likely to be much greater.

> IX Termination Liability
>
> B If written notice of termination is delivered to BellSouth to be effective prior to the end of the current V&T Contract Year, BellSouth will bill ____ the appropriate termination charges calculated in A. above, in addition to an amount equal to the difference between the current Contract Year to date billing for V&T Eligible billings and the current year Minimum Annual Revenue Base.

The Minimum Annual Revenue Base for CSA TN98-2766-00 is $5,750,000. Therefore, if the contract is to terminate in the middle of the year and the customer has been billed only $2,850,000, the termination penalty will be $2,850,000 in addition to the flat rate charge as stated by Mr. Frame.

Q. Would the customer be subject to any additional termination charges?

A. Yes. Paragraph C of Section IX of CSA TN98-2766-00 provides:

> C. The application of termination charges pursuant to this Section shall not affect the application of termination charges pursuant to the tariff or any other agreement.

In accordance with BellSouth's tariffs, the customer would be liable for termination charges for some of the services listed on Mr. Frame's Exhibit RLF-1. For example, from the discounted rate for MegaLink® ISDN identified on the exhibit, it appears that the customer has entered into a 49-72 month agreement[1] to purchase this service. Therefore, the provision of BellSouth's Tariff Section B7.5.4 E would apply.

> Tariff Section B7.5.4
>
> E. A Termination Liability Charge is applicable at the date of termination. The applicable charge is dependent on the contract period subscribed to and will be equal to the number of months remaining in the contract times the monthly rate provided under the contract.

Therefore, not only would the customer be liable for the

[1] The rate for MegaLinK® ISDN on Exhibit RLF-1 is $217.50 with a 13% discount Therefore the pre-discounted rate would be $250 ($217 5/ 87%= $250.00) BellSouth Tariff Section 7 5 6 D (1) Primary Rate Interface for a 49-72 month commitment is $250 00 / month USOC PRFS1

termination penalty in Section IX of the CSA, but the customer would also be required to pay $250 for each MegaLink ®ISDN Primary Rate Interface for each of the remaining months on its contract to purchase MegaLink ®ISDN service.

Q. Are the termination provisions in this CSA consistent with those included in other Bell CSAs?

A. No. The termination provisions in this CSA and CSA KY 98-4598-00 are different from some other CSA's filed by Bell. For example, in some CSAs the cancellation language is patterned as follows:

> If Subscriber cancels this Agreement at any time prior to the expiration of the service period set forth in this agreement, Subscriber shall be responsible for all termination charges. Unless otherwise specified by tariff, termination charges are defined as **reasonable** charges due or remaining as a result of the minimum service period agreed to by Company and Subscriber and set forth in the Attachments. (Emphasis added.)

While the provision calls for the termination charge to be reasonable, as evident from information obtained during our review of the CSA process, the actual charges set forth in the CSA Attachments are arbitrary and dependent upon the ability of the customer to

negotiate. For example, Bell provided copies of correspondence between certain of its employees that included the following discussions:

> ....wants the first year termination liability to be reduced $75K ($325,000 to $250,000). This shouldn't be an issue since I added an additional $!00K(sic) as a termination liability in the first year of the Supplemental agreement.
>
> ....I have done some calculations on the services that we have under contract at _____. Based on the termination penalties on these contracts I share _____ concern that they would be "double gigged" in the highly unlikely event of an early termination on an MSA. For example, if_____ enters into a 36 month MSA agreement with an effective date of 2/01/97, but they cancel ALL services through BellSouth at the conclusion of year 1 on 2/01/98, their termination penalties would be as follows
>
> $938,000 Contract termination penalties (ESSX, SMARTPath, PRI ISDN, Synchronet)
> $775,000 MSA cancellation penalty at end of Year 1
>
> $1,713,000 TOTAL TERMINATION PENALTY
>
> _____understands that the individual contracts and the MSA agreement are two different issues, but they do not feel that we should have such hefty penalties. My contact tells me that if we can get the MSA penalties more like the following, we can continue with negotiations:
>
> $266,000 Year 1
> $134,000 Year 2
>
> (See Exhibit RTB-3.)

From these statements, I infer that the termination liabilities included in these contracts are not based on Bell's unrecovered costs or damages that might be incurred by Bell if the contract is breached by the customer. Instead, termination liabilities are largely arbitrary and subject to the ability of the customer's and of Bell's negotiators.

Further, these exorbitant Termination Liability amounts are not a financial incentive to the customer as Bell contends, but a penalty imposed on customers. Otherwise, the customer might select services from a competing telecommunications service provider that offers more economical rates. A true financial incentive for the customer would be additional discounts at greater service volumes, not the penalty of paying for services the customer no longer wishes to receive.

The revised termination provisions in CSA KY98-4598-00, however, tie the penalties to the discounts received, and do not reflect incurred costs or damages to Bell, which might result from the termination of the contract.

Q. Does CSA KY98-4958-00 include the same "Rate Assurance" provisions as CSA TN98-2766-00?

A. No. The Rate Assurance provision is not included in KY98-4958-00.

Q. Is the computation of the termination penalty under CSA KY98-4958-00 consistent with computation under CSA TN98-2766-00?

A. No. Although when Bell filed the CSA, a page identified as "Additional Terms and Conditions" included replacement language for the computation of the termination liability that would have been similar, Mr. Frame testified that the substitute language was not accepted for CSA TN98-2766-00. (See Frame Direct Testimony, Page 17, Line 16.)

Q. Does the Consumer Advocate Division have a concern with the termination provisions in CSA KY98-4958-00?

A. Yes. While the procedure for determining the termination penalty is different in CSA KY98-4958-00 than in CSA TN98-2766-00, it also results in an amount that is not related to any cost or damages that Bell would incur as the result of the contract being prematurely terminated.

In fact, the procedure works somewhat in reverse of what one might expect. It would normally be expected, that the longer the contract has been in effect and the less time remaining on the contact when terminated, the smaller the termination liability. This is not the case as stated in the revised language of CSA KY98-4958-00. The termination penalty actually increases each month for the first year and

then remains constant. Therefore, if the customer terminates the contact at the end of the first year or even at the end of the 35th month, when there is only one month remaining on the contract, the termination penalty will be the same. Obviously, any damages, that Bell incurs as the result of the early termination, would not be the same if the contract is terminated after one year when compared to termination with only a month remaining. This termination penalty is unjust and unreasonable.

Q. You state that the termination penalty is not related to costs incurred by Bell. Doesn't the revised language in KY98-4958-00 specifically address costs incurred by Bell?

A. Yes, it does. The recovery of the costs, however, is in addition to the penalty computed based on the length of time that the CSA has been in place.

Q. Are there other provisions in these CSAs that cause you concern?

A. In addition to the anti-competitive "Rate Assurance" provision in CSA TN98-2766-00 (TRA Docket #99-00210) and the punitive termination provision as previously discussed, these and other CSAs filed by Bell are discriminatory.

Q. Does Tennessee law prohibit discrimination?

A. Yes. Discrimination is addressed in several statutes. For example, Tenn. Code Ann. §65-4-122. Discriminatory charges - Reasonableness of rates - Unreasonable preferences - Penalties provides the following:

> (a) If **any common carrier** or public service company, directly or indirectly, **by** <u>any special rate</u>, <u>rebate</u>, <u>drawback</u>, or **other device, charges, demands, collects,** or **receives** from any person a **greater** or **less compensation** for **any service** within this state **than it charges, demands, collects**, or **receives** from **any other person** for **service of a like kind under substantially like circumstances and conditions**, and if such common carrier or such other public service company **makes any preference between the parties aforementioned** such common carrier or other public service company commits **unjust discrimination**, which **is prohibited** and **declared unlawful**. (Emphasis Added.)

Q. Is Bell a common carrier?

A. Yes.

Q. Does Bell directly or indirectly, by any special rate, rebate, drawback, or other device, charges, demands, collects, or receives from any person a greater or less compensation for any service within this state than it charges, demands, collects, or receives

from any other person for service of a like kind under substantially like circumstances and conditions?

A. Yes. Paragraphs II A, B, C, D, & E, III A of CSA KY98-4958-00 (TRA Docket #99-00244) and paragraphs II A & B of CSA TN 98-2766-00 (TRA Docket #99-00210) provide that service will be furnished to these two customers at a discounted rate, with the amount of the discount being dependent upon the amount of service to which the customer commits to purchase. The level of the service commitment is measured by total revenue collected from the customers. If the actual volume (revenue) during the contract year exceeds the projected volume, the customer is to receive a rebate.

As provided in paragraph III A, the customer served under CSA TN98-2766-00 will be billed for services at rates 10% less than the tariffed rates if the customer purchases the contracted level of service. If, however, in accordance with paragraph XIV B, the customer's annual billing equals or exceeds $6,250,000, the customer will receive a rebate equal to an additional 1%. If the customer's actual purchase equals or exceeds $6,750,000, the rebate is increased to an additional 2% and to an additional 3%, if the actual purchase equals or exceeds $7,250,000. Bell is providing these customers both a discount and a rebate.

Q. Are the same discounts and rebates provided to these two customers of the CSAs in this case?

A. No. When the discount and rebate provisions of the two contracts in this proceeding are compared, it is obvious that the amounts being charged, demanded, billed, and collected are lesser for one than the other. For example, the customer served in CSA TN98-2766-00 is required to purchase $4,750,000 in order to obtain an 8% discount, while the customer served under CSA KY98-4598-00 is required to purchase half the service of $2,375,000 to obtain the same 8% discount. In order to obtain an 11% discount, the customer served under CSA TN98-2766-00 must purchase $6,250,000 of service, while the customer served under CSA KY98-4598-00 must purchase only $3,000,000.

Q. Is the difference in the amount of the discounts based on a difference in the cost?

A. No. The CA previously requested Bell to admit that the difference in the rates charged customers under the approved tariffs and the CSAs was no greater than the difference in the cost of providing the service to the customers served under the CSAs. Bell responded that it could neither admit nor deny because it had not performed the analysis required. Consistent with its response to our

discovery request, the cost studies filed by Bell in support of the CSAs in this docket do not reflect customers specific cost, but are the same cost supports that Bell filed in support of its tariffed rates for the services provided under the CSA. When this data is reviewed, it found that many of the services are common to both CSAs, and that the same costs are identified. This again supports the position that the difference in the rates charged under CSA KY98-4958-00 (TRA Docket #99-00244) and CSA TN98-2766-00 (TRA Docket #99-00210) is not based on the costs of providing the services.

Q. Are the same discounts and rebates provided to these customers as the discounts and rebates provided to other customers, who purchase service under CSAs?

A. No. To illustrate that different discounts and rebates are being offered. The following table is provided, which identifies the percent discount provided under the two CSAs that are the specific subject of these dockets as well as discounts provided to customers that are parties to four other CSAs filed by Bell. While each of the CSAs requires the customer to commit to purchase service for a three year period, the amount of service that the customers must agree to purchase in order to qualify for the discounts varies greatly. As I previously explained, the customer served in CSA TN98-2766-00 is

required to purchase $4,750,000 in order to obtain an 8% discount, while the customer served under CSA KY98-4598-00 is required to purchase half the service, $2,375,000 to obtain the same 8% discount.

In order to obtain an 11% discount, the customer served under CSA TN98-2766-00 must purchase $6,250,000 of service, while the customer served under CSA KY98-4598-00 must purchase only $3,000,000.

This disparity in the amount of revenue required to obtain the discount is also present with CSA TN97-1641-00, which requires the customer to purchase $5,000,000 of service to obtain a 12% discount, while the customer served under CSA TN98-2766-00 must purchase $6,500,000.

Similarly, the customer that is a party to CSA TN97-5138-00 receives a 10.5% discount by committing to purchase only $1,360,000 of service, while the customers under CSAs TN98-2766-00 and KY98-4598-00 must purchase $5,750,000 and $2,750,000 respectively, in order to obtain 10% discounts.

Other Example CSAs

Discount Provided by CSA	Required Volume under CSA TN98-2766-00	Required Volume under CSA KY98-4598-00	Required Volume under CSA TN96-7973-01	Required Volume under CSA TN96-7961-02	Required Volume under CSA TN97-1641-00	Required Volume under CSA TN97-5138-00	Required Volume under CSA TN96-7967-03
2.0%							
3 0%							
4.0%			$104,236				
5 0%				$284,648			$63,516
6 0%		$2,000,000					
7 0%		$2,250,000					
8.0%	$4,750,000	$2,375,000					
9.0%	$5,250,000	$2,500,000					
10 0%	$5,750,000	$2,750,000					
10 5%						$1,360,000	
11 0%	$6,250,000	$3,000,000					
11 5%						$1,632,000	
12 0%	$6,750,000				$5,000,000		
12 5%						$1,904,000	
13 0%	$7,250,000						

Q. Why is it appropriate to compare the discount in these CSAs that are subject to this proceeding with the discounts offered in other CSAs?

A. To determine if CSAs, CSA TN98-2766-00, and CSA KY98-4598-00 are discriminatory, it is not appropriate to simply compare the

rates charged the two customers served under these two CSAs. The rates charged in these dockets must be compared to those charged other customers, who are provided service under tariffed rates or under other CSAs. The table, which is provided here, is not an attempt to identify all of the CSAs that provide for discriminatory rates. The comparisons' presented in the table, however, accurately represent the unjust disparities in the rates that exist among the CSAs filed by Bell.

Q. Have you made any comparison of the rates charged for specific services billed under the CSAs and those for customers billed under Bell's General Subscriber Service Tariff rates?

A. Yes. The following table compares the rates charged for some of the services under the provision of the CSAs with the rates for the same service billed at the General Subscriber Service Tariff rates. Again, these are only examples of the disparity and are not intended to be all inclusive. Attachment III,[2] which was filed with the TRA in support of CSA TN98-2766-00 and identifies the services provided in accordance with that CSA, consists of 17 pages. I have not prepared a schedule that compares the discounted rates charged with the tariffed rates for each service on that listing or for all of the services listed on

[2] Exhibit RLF-1 filed by BellSouth as an exhibit to Mr. Frame's testimony is a duplicate of Attachment III.

similar supporting schedules filed in support of the other CSAs. Instead, I have compared the rates for some of the more familiar services.

As shown in this table, the price demanded, charged, and collected from a customer, who purchases one party business line (USOC[3] 1FB) service at the tariffed rate in a Group 5 exchange is $39.70 per month. (Group 5 Exchanges are those exchanges, which have 300,001 -500,000 lines, see BST TN Tariff Section A 3.2.1 Eighth Revised Page 1.1) Bell collects $34.54[4] per month for this service from the customer billed in accordance with CSA TN98-2766-00. This is a $5.16 difference. The customer served under KY98-4598-00 is charged $35.53 [1] and the customers served under CSAs TN96-7961-02, TN97-1641-00, and TN97-5138-00 are charged $37.72, $34.94, and $31.87 respectively, for this same one party business line service. This evidence shows an unjust difference in rates for exactly the same service.

[3] USOC (Universal Service Ordering Code)

[4] This is the rate at the maximum discount level provided under the contract.

Q. Are their similar disparities between the rates charged customers served under Bell's General Subscriber Service Tariff and those served under these CSAs for other services?

A. Yes. The charges for single business lines in rate group 3 & 4 exchanges are compared as are the charges for MegaLink ® ISDN, MegaLink ®Channel Service, and DID service. In each instance, the customers, who are billed the General Subscriber Service Tariff Rates pay more than those billed under the CSAs.

Q. Are the same amounts billed for these services under the various CSAs?

A. No The discounts provided under the CSAs vary. Therefore, the amount charged for the same services are different under the various CSAs.

Service	USOC	Tariff Rate	Rate CSA TN98-2766-00 [5]	Rate CSA KY98-4958-00 [1]	Rate CSA TN96-7961-02	Rate CSA TN96-7973-01	Rate CSA TN97-1641-00	Rate CSA TN97-5138-00 [1]
Flat Rate Business Line	1 FB Group 5	$39 70	$34 54	$35 33	$37 72		$34 94[6]	$31.87[7]
Flat Rate Business Line	1 FB Group 4	$39 05	$33 97	$34 75				
Flat Rate Business Line	1 FB Group 3	$32 75	$28 49	$29 15		$31 44[8]		
Megalink ISDN	PRFS1 (3yr commit)	$260 00	$217 50[9]		$247 00	$240 00		
Megalink Channel Service	VUM 24 (3 yr commit)	$189 00	$182 70[10] 164 43	$168 21				$165 38
DID/AIOD	NDT	$20 00[11]	$17 40	$17 80	$19 00	$19 20	$17 60	$17 56

[5] Prices based on the maximum discount provided under the CSA

[6] Tariff Rate Group 1 $39 70 X 88%=$34.94 (100%-12%=88%)

[7] Discounted rate per workpapers filed with the TRA Staff in support of CSA

[8] Clarksville is a Class 3 rate schedule wire center. The business rate for a class 3 wire center is $32.75 (BellSouth Tariff Eighth revised page 1.1 Tariff Section A3 2 1, and Fifteenth revised page 20, Tariff Section A3 7 1) Discount is 4% $32 75 X 96%=$31 44.

[9] The Tariff rates for MegaLink®ISDN service are $360/ month, Month to Month, $260/ month with a contract commitment 24 - 48 months, $250/ month with a contract commitment 49-72 months, $240 / month with a contract commitment 73 - 96 months (BellSouth Tariff Section B7 5.6 First Revised Page 37 4)While each of these contracts are for 3 years the discount for MegaLink ®ISDN service under CSA TN98-2766-00 appears to have been computed on Attachment III assuming a $250 / month rate indicating a commitment of at least 49 months. It appears that the discounted rate for TN96-7961-02 was computed based on the $260/month for a 3 yr commitment The discounted rate for TN96-7973-01 again appears to have been computed assuming that the $250/month rate for a 49 to 72 month commitment was used $250 discounted 4% is $240.

[10] The Tariff rates for MegaLink® Channel Service are $210/month, Month to Month, $189/ month with a contract commitment 24 - 48 months, $171/ month with a contract commitment 49-72 months, $154/ month with a contract commitment 73 - 96 months (BellSouth Tariff Section B7 3 4 First Revised Page 19)Each of these contracts are for 3 years. Therefore it would appear that the discounts would have been computed based on the $189 tariffed rates The discounted rate for CSA TN98-2766-00 would be $164 43 (13% discount) instead of the discounted rate of $182 70 based on the Month to Month rate of $210 The result is an actual discount is only 3 4%. (182 70/189=96 6%) [Four MegaLink® Channel were discounted to $164 43, apparently based on a 3 yr contract commitment.]

The discounted rate for KY98-4958-00 was computed correctly using the $189 rate for a 24-48 month contract $189 discounted at 11% is $168 21

[11] BellSouth Tariff Section A12.7 2 Eighth Revised Page 2

Q. Is the customer billed under CSA TN98-2766-00 provided any additional discounts from that specified in the CSA?

A. Yes. For example, Bell's Tariff Section B7.5.6 First Revised Page 37.4 provides that the monthly rate for MegaLink® ISDN service is $360. If the subscriber commits to take the service for a period of 24 to 48 months, the rate is discounted to $260. (A 27.7% discount.) If the customer commits to take the service for a period of 49 to 72 months, the rate is reduced to $250 and to $240 with a commitment of from 73 to 96 months. From the price-out filed by Bell with the Authority in support of this CSA, it is apparent that the customer is being given a discount for committing to purchase MegaLink®ISDN for at least four years. The discounted rate shown on Attachment III filed in support of the CSA is $217.50 per month, which is a 13% discount off of the $250 tariffed rate charged to a customer that signed a 49 to 72 month commitment. It appears that the service billed in accordance with CSA TN98-2766-00 is receiving a 30.55% discount for committing to continue to purchase the service as provided in the tariff and an additional 10%-13% discount[12] under the CSA for a total discount of 37.5% to 39.6%[13].

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[12] The 13% discount assumes the customer billing reaches the maximum discount level provided under the CSA The discount at the contract level is 10%.

[13] At 10% discount level under the CSA the rates would be $225. ($250 X 90%=$225) [$225/$360=62.5%, 1-62 5%=37 5%] At 13% discount level under the CSA the rate would be

The customers billed under the provisions of CSAs KY98-4958-00, CSA TN96-7961-02, CSA TN97-5138-00, and CSA TN96-7973-01 appear to have also received discounts in accordance with the provision of the Tariffs in addition to the discounts provided in the CSA.

Q. Do the tariffs also provide for termination penalties?

A. Yes. The tariffs do have termination provisions. In some instances, when the customer is provided a discount for committing to purchase service over an extended period of time. For example, Bell's Tariff Section B7.5.4 E provides that:

> A Termination Liability Charge is applicable at the date of termination. The applicable charge is dependent on the contract period subscribed to and will be equal to the number of months remaining in the contract times the monthly rate provided under the contract.

Similar provisions are included in other tariff sections, where a discounted rate is provided in exchange for customer's commitment to purchase service over an extended period of time.

Q. In the event that the customer being billed under the CSA

$217.50 ($250 X 87%=$217 50) [$217.50/$360=60.4%, 1-60 4%=39.6%]

transfers the service to a competitor of Bell, which termination penalty would apply?

A. Both penalties would apply. Section IX paragraph C of CSA TN98-2766-00 and the first sentence of Section IX paragraph B of CSA KY98-4958-00 provides the following:

> The application of termination charges pursuant to this Section shall not affect the application of the termination charges pursuant to the tariff or any other agreement

Q. Mr. Frame, testifying on behalf of Bell, contends that the CSA does not modify the tariffed rates:

> **Q. WHAT RATE OR PRICE DOES BELLSOUTH CHARGE THIS CUSTOMER FOR TELECOMMUNICATIONS SERVICES?**
>
> **A. The rates charged to the customer are those specified in the appropriate tariffs and available to any customer ordering the same services. This CSA does not modify those tariffed rates in any way, but rather provides discounts based on billed revenue from the eligible services identified in the contract. (See Frame Direct Testimony, Page 7, Lines 12-17.)**

Is this statement consistent with the documents that BellSouth has filed in support of its CSAs?

A. No. In support of its CSAs, Bell had filed documents that provide the same information as Frame Exhibit RLF-1, which identifies each service subject to the CSA and for **each** such service identifies the following:

1. The USOC
2 Service Description
3. Quantity
4. **Discounted Rate**
5. Annual Revenue
6. Unit Cost
7. Annual Cost
8. Annual Contribution
9. Percent Contribution

(Emphasis Added.)

Q. You state that this document identifies the discounted rates for the individual service provided under the CSA. Are the tariffed rates for the individual service stated on the document?

A. No. The tariffed rates for the services are not identified. The only rates are the individual discounted rates. This document identifies each individual service being discounted, and the discounted rate to be billed under the CSA for each specific service.

Q. Does the Frame Exhibit RLF-1 identify CSA rates for one party business service in a Group 5 exchange than that charged for a Group 4 exchange?

A. Yes. On page 3 of Exhibit RLF-1 four rates are identified for Flat Rate Business line: $34.54, $33.97, $28.49, $26.80 and $23.93.

Q. Are these the tariffed rates for a Flat Rate Business line in the various exchange groups?

A. No. These are the discounted rates. The tariffed rates for a 1 party business lines for group 5, group 4, group 3, group 2, and group 1 exchanges, are $39.70, $39.05, $32.75, $30.80, and $27.05, respectively. The tariff rates and the rates discounted at 13% as shown on Mr. Frame's Exhibit RLF-1 are presented in comparative format in the following table.

Service	Tariffed Rate[14]	Tariffed Rate Discounted 13%
1 FB Group5 exchange	$39 70	$34 54
1 FB Group4 exchange	$39.05	$33.97
1 FB Group3 exchange	$32.75	$28.49
1 FB Group2 exchange	$30.80	$26.80
1 FB Group1 exchange	$27.05	$23.53

The filing of the exhibit that compares the revenue from the individual services after a discount with the cost of providing the individual services is

[14] BellSouth Tariff Section A3.2.1, Eighth Revised Page 1 1.

not consistent with Mr. Frames position that the individual service rates are not discounted.

Q. Are Bell's CSAs evidence of anti-competitive behavior?

A. Yes. Bell's CSAs are evidence of anti-competitive behavior. Tenn. Code Ann §65-5-208. Classification of services - Exempt services - Price floor - Maximum rates for non-basic services states the following:

> (c) Effective January 1, 1996, an incumbent local exchange telephone company shall adhere to a price floor for its competitive services subject to such determination as the authority shall make pursuant to § 65-5-207. The price floor shall equal the incumbent local exchange telephone company's tariffed rates for essential elements utilized by competing telecommunications service providers plus the total long-run incremental cost of the competitive elements of the service. When shown to be in the public interest, the authority shall exempt a service or group of services provided by an incumbent local exchange telephone company from the requirement of the price floor. **The authority shall, as appropriate, also adopt other rules or issue orders to prohibit cross-subsidization, preferences to competitive services or affiliated entities, predatory pricing, price squeezing, price discrimination, tying arrangements or other anti-competitive practices.**

(Emphasis added.)

Q. Do the prices for services provided under the CSAs reflect price discrimination?

A. The economic definition of price discrimination is defined as, "the practice of selling the same product at two or more prices where the price differences do not reflect cost differences."[15] The price of service provided to the customers subject to the CSAs is different from the price of the service when provided under tariff rates. In addition, the same services provided under different CSAs are at different prices.

Bell does not contend that the cost of providing the service differs. In fact, the documents that Bell has filed in support of the CSAs, which identifies the cost of the various services, is the same as the cost used to support the tariffed rates. (See Attachment III to the various CSAs and Bell's Exhibit RLF-1 filed with Mr. Frame's testimony.) While the rates are different, the costs of providing the service are the same. Bell is selling the same product at two or more prices, where the price differences do not reflect cost differences. By definition, the rates are discriminatory.

[15] Kaserman, David L. and Mayo, John W., *The Economics of Antitrust and Regulation*, Orlando. The Dryden Press, 1995

Q. Are there tying arrangements included within the CSAs?

A. While there is no specific wording in the CSA state there are tying arrangements, Mr. Frame has entered testimony that; "....the discount on billed revenue is determined by the specific mix for each customer . . . " (Frame Direct Testimony, Page 14, Lines 13-14.) The discounts are therefore apparently specifically tied to the combination of services purchased by the customer. This would indicate, that in order to obtain a discount on one service, a customer may have to purchase another specific service or a specific group of other services.

Q. Do the CSA's include other anti-competitive practices?

A. Yes. As Dr. Brown will provide in more detail, the CSAs provide that Bell will react to the same economic event differently based on the underlying cause of the event. If the event is caused by a competitor, Bell's actions will be different from its actions if the event has other causes. For example, in Paragraph X of CSA TN98-2766-00, the following language is found:

> In the event of a Business Change as defined herein which significantly reduces the volume of network services required by_____, and those subsidiaries listed in Appendix III, with the result that _____ is unable to meet its Minimum Annual Revenue Base under this Agreement (notwithstanding _____ best efforts to avoid such a shortfall), BellSouth

and_____ shall cooperate in efforts to develop a mutually agreeable alternative that will **reduce _____ liability** under the Minimum Annual Revenue Base, the Annual Revenue Base and the Discount levels which satisfies the concerns of both parties and complies with all applicable legal and regulatory requirements. Such alternative will reduce the Customer's Annual Revenue Base, Minimum Annual Revenue Base and the corresponding Discount levels to the extent of any shortfall resulting from a Business Change as defined herein. **This provision shall not apply to a change resulting from a decision by _____ to transfer portions of its traffic or projected growth to providers other than BellSouth.** (Emphasis added.)

Similar language is found in CSA KY98-4958-00.

Q. How does this language indicate that Bell will react differently to the same economic event dependent on the underlying cause?

A. As stated in the previously quoted paragraph, Bell will work with the customer and will reduce or adjust the minimum annual revenue base and the related discount level if the decline is the result of a business change. However, if the decline in demand is caused by the customer electing to transfer part of its telecommunications operations to a competitor of Bell, no such reduction will be made. From Bell's perspective the end result of a decline in the level of

service purchased by the customer is the same. Bell will receive less revenue. In accordance with the provision in the CSAs, Bell's actions in response to such a decline will be different depending upon the cause in the revenue decline and will be punitive toward the customer if the decline is caused by a competitor. Dr. Brown will provide a more thorough discussion on this matter.

Q. In his testimony Mr. Frame states:

> **Although I am not a lawyer, the discount on billed revenue is determined by specific service mix for each customer as described above. Because these customers have a different product mix, they are not similarly situated such that BellSouth can lawfully offer the customer different discounts and revenue commitments. (See Frame Direct Testimony, Page 14, Lines 13-16.)**

Do you agree with his conclusion that because two customers subscribe to different groups of services they are not similarly situated?

A. No. If you accept his definition of similarly situated, the idea of uniform tariffed rates for business services is useless. Using his argument as justification, Bell could charge a business customer, who subscribes to only a single business line, more for that line than it would charge the customer's business neighbor for a single business

line, who also purchases a call forwarding. Since the customers would have a different product mix, Mr. Frame's definition would allow Bell to find that the two business customers would not be similarly situated.

Additionally, if a business customer had an office with three business lines with caller ID on each line and another customer occupying an adjacent office in the same building has four business lines and call waiting on each line, Mr. Frame's definition would find these customers are not similarly situated.

If adopted, Mr. Frame's definition of similarly situated could virtually result in each customer being placed in a separate one customer class.

Q. Is there some relationship between the mix of services being provided and the amount of discounts provided under the individual CSAs?

A. The revenue contribution is largely a matter of the mix of services being provided. Using the revenue and cost data filed as Bell's Exhibit RLF-1 and the corresponding schedules filed with other CSAs, I have compared the discounts awarded with the weighted per cent contribution before and after the discount for various CSAs. The results as shown on Exhibit RTB-4 do not reflect a consistent pattern. It does appear that the customers, whose mix of services produces the

lesser contributions before discounts, are the customers who are also receiving the larger discounts. For example, the services discounted under TN98-2766-00 produce a contribution of 127% before the rates were discounted by 13%. Similarly, the services for CSA KY98-4958-00 resulted in a contribution of 137% before the discounts of 11%-13%. In contrast, the contributions from the services being discounted under CSA TN97-7973-01 produce a contribution of 999% before the 4% discount, while the services under CSA TN97-7961-01 produce a contribution of 540% before the 5% discount.

Q. Did you compute the "contribution" consistent with the computation on Bell's Exhibit RLF-1?

A. Yes.

Q. Are any of the services discounted under the CSA TN98-2766-00 and CSA KY98-4958-00 being discounted below the cost of providing the service as identified by Bell?

A. Yes. On Bell Exhibit RLF-1, there are 80 instances of service being discounted below the cost as identified by Bell for CSA TN98-2766-00 and 15 instances of service being discounted below cost under CSA KY98-4958-00. The USOCs and the resulting negative contributions are presented on Exhibit RTB-5. The service

descriptions, quantities, and cost of these are presented on Bell Exhibit RLF-1.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE: PROCEEDING FOR THE PURPOSE OF ADDRESSING COMPETITIVE EFFECTS OF CONTRACT SERVICE ARRANGEMENTS FILED BY BELLSOUTH TELECOMMUNICATIONS, INC IN TENNESSEE.	)	DOCKET NO. 98-00559

AFFIDAVIT

I, Robert T. Buckner, Senior Regulatory Analyst, for the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Rebuttal Testimony represents my opinion in the above referenced case and the opinion of the Consumer Advocate Division

Robert T. Buckner

Sworn to and subscribed before me
this 30th day of July, 1999.

Teresa A. Harris
NOTARY PUBLIC

My commission expires on: Jan. 25, 2003

15999

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE: PROCEEDING FOR THE PURPOSE OF ADDRESSING COMPETITIVE EFFECTS OF CONTRACT SERVICE ARRANGEMENTS FILED BY BELLSOUTH TELECOMMUNICATIONS, INC. IN TENNESSEE.
DOCKET NO. 98-00559

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EXHIBITS
of
ROBERT T. BUCKNER

****

July 30, 1999

Exhibit RTB-1

Robert T. Buckner (Terry)

Senior Regulatory Analyst

Office of the Attorney General for the State of Tennessee

Consumer Advocate Division

Additional Education Background:

Micro-Computer Training, **University of Wisconsin, Madison**

Cost Separations School, **United States Telephone Association, San Diego**

Rate Case School, **Arthur Andersen LLP, Chicago**

Telecommunications Conference, **University of Georgia, Athens**

NARUC Conference, **Michigan State University, Lansing**

Management Training Seminar, **Vanderbilt University**

Interstate Access Settlements, **National Exchange Carrier Association**

SEARUC Conferences, **Birmingham, AL. and Charleston, S.C.**

Telephone Plant Accounting Program, **Ernst and Young LLP, Atlanta**

Before the

TENNESSEE REGULATORY AUTHORITY

In Re: Nashville Gas Company

Docket No. 96-00977

****

DIRECT TESTIMONY

of

R. Terry Buckner

****

October 28, 1996

Q. Please state your name for the record.

A. My name is R. Terry Buckner.

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. How long have you been in the utility industry related employment?

A. Approximately nineteen years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. My responsibilities included testifying before the Commission as to the appropriate cost of service for public utilities operating in Tennessee. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS") for eight years and the First Utility District of Knox County for three years.

Q. What is your educational background and what degrees do you hold?

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. Would you briefly describe your responsibilities as a Senior Regulatory Analyst since your employment with the CA?

A. I prepared testimony and exhibits as an employee with the Commission before becoming a member of the CA. My responsibilities have not been altered significantly since my employment change.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present information to the Tennessee Regulatory Authority ("TRA") on the appropriate operating expenses other than depreciation for the attrition year November 1, 1996 to October 31, 1997 for Nashville Gas Company ("Company"). Additionally, I will present the CA's calculation of other taxes and income taxes for the attrition year.

Q. What is an attrition year?

A. An attrition year is a synonym for a forecasted or projected 12 month period.

Q. Please identify the issues regarding operation and maintenance expenses for Nashville Gas Company in Docket #96-00977?

A. The CA Exhibit, Schedule 8 indicates the differences in the CA and the Company forecasted expenses for the twelve months ended October 31, 1997. The total operation and maintenance expenses projected by the CA are $7,838,394 lower than the operation and maintenance expenses projected by the Company for the attrition year. The differences that make up this $7.8 million include the following just and reasonable exclusions, reductions and increases: (1) the CA has excluded approximately $1.6 million in excessive net expense growth and inappropriate expenses for setting rates for the ratepayer; (2) a $1.9 million reduction in forecasted expenses associated with sales promotion and advertising; (3) a $1.3 million reduction in forecasted allocated net pension expense; (4) a $2 million reduction in allocated service company charges; (5) a $.6 million reduction in the Company's Long Term Incentive Pay plan; and (6) a $.4 million increase in the amount of General and Administrative expenses which are capitalized and charged to non-

regulated operations.

Q. Please explain the just and reasonable $1.6 million exclusion due to forecasted expense growth differences of the Company and the CA for the attrition year.

A. The primary reason for the exclusion is the difference in forecasted expense growth caused by the Company's use of an excessive inflation factor and unsubstantiated growth rates for various expenses. The CA used an annual customer growth of 5.1% and an annual inflation rate of 2.39% which generates a compound growth rate of 12.66% through the attrition year ended October 31, 1997. The information used to determine the CA's forecasted inflation factor was taken from the publication "Blue Chip Indicators."[1] The percentage increase of the attrition year Gross Domestic Product ("GDP") deflator over the test year GDP deflator, equates to an annual inflation rate of 2.39%. The annual inflation rate of 2.39% generates a compounded growth rate of 4.01%. The compound growth rate of 12.66% (customer growth plus inflation growth compounded) was applied to most of the CA's test year ended February 1996 expenses excluding salaries and wages.

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[1]The Blue Chip Economic Indicators publication is a consensus summary of fifty top economists in the United States.

Q. How does the 12.66% growth rate compare with the Company's experience in recent years?

The CA's compounded growth rate is somewhat greater than the actual annual expense growth of the Company over the last thirty-three months ended April 1996 of 3.735%, which was a compounded growth rate of 10.61%. In contrast, the Company used an unjust and unreasonable projected 16.10% compounded growth rate for a twenty-two month period ending October 31, 1997 for certain expense items based on an annual inflation rate of 3.2% and an annual customer growth rate of 5.1%. The Company's overall operation and maintenance expenses, however, are projected to grow 21.31% for the attrition year over actual 1995.

One difference from the CA projection is that, instead of using the GDP deflator, the Company used the CPI inflation indicator from the Economic Forecasting Center of Georgia State University for its speculative annual inflation rate. The GDP deflator, which was used by the CA, has been traditionally used by the Commission and TRA staff, not the CPI inflation factor proposed by the Company. Current evidence supports the CA's projected annual inflation rate of 2.39%. The difference in growth rates results in a lower expense amount of approximately $1.1 million for expenses excluding salaries and wages.

This amount, also, recognizes an error by the Company in their growth of Injuries and Damages of approximately $.4 million. The Company miscalculated their projected amount of Injuries and Damages for the attrition year. Additionally, the CA has deducted $145,983 of non-recurring expenses recorded during the test year ended February 28, 1996.

Finally, the CA has used actual employees and wage rates as of August 31, 1996 grown during the attrition year. The Company used outdated 1995 actual employee levels. This difference results in $307,473 in lower salaries and wages than the Company's salary and wage projection for the attrition year.

Q. Please explain the forecasted difference in advertising and sales promotion expense amounting to $1.9 million.

A. The CA requested that the Company provide a detailed analysis of the 1995 projected advertising and sales promotion expenses in the following categories: Institutional, Conservation, Promotional, Informational and non-regulated Promotional for the sale of appliances. The Company's response was such that amounts projected for each advertising category cannot be determined. Since the Company declined to furnish the breakdown of advertising expenditures, it is not clear if the amount includes advertising that

would be included in the rates charged ratepayers. Without such information, there is no possible way to determine if the advertising expense budgeted by the Company is appropriate for setting rates. As with any other expense, the Company is obligated to prove that costs that are recovered in rates are just and reasonable. Since the information is not available, the CA has excluded approximately $1.9 million ($.8 million in salaries and wages) in advertising and sales promotion expenses. Since the Company failed to support the cost of advertising expense, we have included an amount based on a standard adopted by the Commission. Further, regarding advertising expenses Commission rule *1220-4-5- 45* (Attachment) states, "A utility may not recover from any person other than their shareholders (or other owners) any direct or indirect expenditure for promotional or political advertising. The term 'promotional advertising' means any advertising for the purpose of encouraging any person to select or use gas service or additional gas service or the selection or installation of any appliance or equipment designed to use gas service." We have included an amount equal to .5% of revenues. The CA has applied this threshold to all NARUC Uniform System of Accounts ("USOA") accounts which include advertising and sales promotion expenditures. This standard criteria was set in Commission Docket U-85-7355 for Nashville Gas Company and is consistent with positions taken by the

Commission staff in subsequent gas company rate cases, i.e. United Cities Gas Company, Docket #92-02987. Mr. Hal Novak, of the TRA staff and formerly of the Commission staff, recommended in Docket #92-02987, "that the Commission approve its interpretation of the Commission policy by disallowing all advertising **and** sales promotion expenses that are in excess of .5% of operating revenues." Again, in September 1994, the Commission staff cited the Company in a compliance audit report that "The Company is understating the monthly rate of return that it reports to the Commission" due to excessive advertising expenses which are not in compliance with the Commission Orders. Our case is consistent with the standard as applied in the past.

Q. Please explain the forecasted difference in net pension expense of $1.3 million.

A. The Company's pension plan is fully funded and no funding is anticipated during the attrition year based on the Company's 1995 annual report to their stockholders. Additionally, Company personnel indicated through CA verbal inquiries that there would be no funding during the attrition year. The CA has not recognized any pension expense for the attrition year which is consistent with Federal Income Tax treatment. The Company, however, has unjustly and

unreasonably included approximately $1.3 million of net pension expense in its filing. The Company's recognition of a $1.3 million pension expense in fact causes the ratepayer to pay an expense that has already been paid. Finally, the Commission historically recognized only the actual contributions to the pension plan in the cost of service for setting rates for both telephone and other utilities. Please note the following examples in cases:

Tennessee-American Water Company	U-87-07534	Mar. 1988
Tennessee-American Water Company	89-15388	May 1990
Tennessee-American Water Company	91-05224	Dec. 1991
Tennessee-American Water Company	96-00959	Oct. 1996
Chattanooga Gas Company	U-87-07531	Apr. 1989
Chattanooga Gas Company	91-03765	Apr. 1991
Nashville Gas Company	U-87-07499	Nov. 1987
Nashville Gas Company	89-10491	Nov. 1989
Nashville Gas Company	91-02636	Nov. 1991
Nashville Gas Company	94-01054	Oct. 1994
United Cities Gas Company	89-10017	Nov.1989
United Cities Gas Company	92-02987	Sep. 1992
Kingsport Power Company	90-05735	Dec. 1990
Kingsport Power Company	92-04425	Nov. 1992
Tellico Telephone Company	91-09061	Feb. 1992
Tennessee Telephone Company	91-09062	Feb. 1992
Concord Telephone Company	91-09063	Feb. 1992

In summary, the Company should not be allowed to recover the $1.3 million a second time.

Q. Please explain the forecasted difference in allocated service company charges of $2 million.

A. The CA has allocated the general and administrative expenses (service company charges) of Piedmont Natural Gas Company ("PNG") based upon the ratio of the number of Nashville Gas customers at the end of 1995 to the total PNG customers. This results in 22.16% of PNG's customers being in Tennessee, therefore, Nashville Gas is allocated 22.16% of PNG's general and administrative expenses. The Company, however, has allocated these expenses based upon the ratio of net plant in Tennessee to PNG's total net plant in service. This method is inappropriate and inconsistent with allocation methods historically used and further, is unjust and unreasonable. Historically, audit procedures have allocated operating expenses based on the number of customers in Tennessee to the total number of customers in all states in which PNG operates. This method was recommended by the Commission Staff in Docket #92-02987. The Company's method for no real reason ignores the distinctive nature of the plant assets in each state as to age, cost and the rate at which the plant is being depreciated and should be rejected. The CA's method of allocation is approximately $.6 million lower than the Company's allocation amount.

Additionally, the Company has included a projection of $2.4 million

in salaries and wages allocated from PNG to Tennessee customers. This amount is $1.6 million higher than the 1995 amount and $1.5 million higher than the test year ended February 1996, a 200% increase from the test year. Although we requested all supporting workpapers, the Company provided no support for the reasonableness and accuracy of this 200% increase which is unjust and unreasonable. There is no evidence that any change in the Company's operations warrant a $1.4 million increase for the attrition year. The Company's projection should be rejected.

Q. Please explain the forecasted difference in Long-Term Incentive Pay plan of $.6 million.

A. The Company has included $.6 million in Long-Term Incentive Pay ("LTIP") during the attrition year. The Company has defined the LTIP as:

> "a shareholder-approved Executive Long-Term Incentive Plan for the purpose of promoting the interests of the Company by attracting and retaining in its employment persons of outstanding ability....provides executives and other key employees of the Company greater incentive to make material contributions to the success of the Company by granting them incentive compensation conditioned upon the corporate achievement of financial and other performance objectives."

Thus, the Company rewards employees if the Company overearns. The Company has defined the performance objective "as being a 5% compounded, average, annual increase in net, real (corrected for inflation) after-tax earnings....Thus, the targets for the periods 1987 through 1991 and 1989 through 1994 were each established as being a 27.6% (5% per year, compounded) increase in net after-tax earnings." After review of the Company's LTIP, the CA recommends exclusion of this expenditure due to the following: (1) The LTIP is based principally on earnings growth. In fact, the plan encourages the executives to seek earnings growth through rate increases such as this one in order to produce growth in earnings instead of performance gains or improved service. In other words increasing rates to the ratepayers for LTIP expenses results in increased earnings, which in turn increases LTIP in the future, and which also increases revenue requirements from the ratepayers in the future. This circular incentive program rewards the Company for increasing rates and harms customers; (2) All LTIP employees receive the compensation regardless of the individual employee's performance; and (3) There is no measurable benefit to the ratepayers.

Q. Have other regulatory commissions rejected the expense resulting from such incentive plans?

Yes, earlier this year the Washington Utilities and Transportation Commission ("WUTC") disallowed incentive pay with the following statement[2]:

> "Plans which do not tie payments to goals that clearly and directly benefit ratepayers will face disallowance in future proceedings. (Emphasis added.)

Additionally, the WUTC commented,

> "....there is a potential tension between quality and earnings. A firm can concentrate on financial elements so heavily that it can lose sight of the importance of providing customer service. In a public utility service, where many customers have no reasonably substitutable alternatives, the Commission must substitute for the competitive market in assuring that customer service remains a priority to the business. Financial goals are at best a very crude way to measure specific efficiencies that employees can accomplish." (Emphasis added)

Finally, in 1995 the South Carolina Public Service Commission staff excluded over $.3 million of Piedmont LTIP[3] (Attachment). In fact, in that case both the South Carolina Commission and the Company

[2]WUTC v. U S WEST Communications, Docket No. UT-950200

[3] In RE. Piedmont Natural Gas Company, Inc. Docket No. 95-715-G, Accounting Exhibit A-1, Line No. 13.

had excluded LTIP amounts in the projected cost of service schedules.

Q. Please explain the forecasted difference of General and Administrative expenses transferred for capitalization and to non-regulated operations in the amount of $.4 million.

The Company has made an error in their calculation of General and Administrative expenses to be transferred for capitalization and to non-regulated operations in the amount of $.4 million for the attrition year. This error was noted in detail on pages 21-22 of the TRA staff's compliance audit of October 14, 1996 (Attachment). Further, the Company was cited by the Commission staff for this same error in a previous compliance audit of September 1994. The Company, as of this date, has failed to correct the error. The Company agreed with the TRA staff finding and has stated that it would implement the change at the beginning of the attrition year, November 1, 1996.

Q. Please identify the differences regarding other taxes and income taxes for Nashville Gas Company in Docket #96-00977.

A. The CA Exhibit, Schedule 9 indicates the differences in the forecasted amounts between the CA and the Company. The other taxes projected by the CA are $.2 million lower than the tax amounts

projected by the Company for the attrition year. This $.2 million difference is due to lower payroll taxes.

Q. Please explain why the CA forecasted difference of approximately $.2 million in payroll taxes .

A. $.163 million of the $.2 million Company overstatement is associated with the unsubstantiated allocation of salaries and wages from PNG (See p.10-11). The residual $.037 million is half due to the Company including the Company's portion of payroll tax on the personal use of the Company cars. The other half is attributable to an overstated salary and wage calculation by the Company as discussed previously (See p.6).

Q. Please explain the forecasted difference in income taxes.

A. The $1.9 million difference in the CA and Company's income taxes is due to lower operating expenses projected by the CA (discussed on P. 3) and the difference in capital structure, specifically the cost of debt or interest expense (See testimony of Dr. Steve Brown).

Q. Does this conclude your testimony?

A. Yes, it does.

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September 19, 1997

Mr David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: Petition of Chattanooga Gas Company to Place into Effect a Revised Natural Gas Tariff
Docket No. 97-00982

Dear Mr. Waddell

I have enclosed an original and thirteen copies of Direct Testimony of Consumer Advocate Division witness Robert T Buckner, Senior Regulatory Analyst in the above referenced matter. Copies are being furnished to counsel of record for interested parties.

Sincerely,

L. Vincent Williams
Consumer Advocate

c Counsel of record

#103900

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE: PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF
DOCKET NO. 97-00982

****

DIRECT TESTIMONY
of
ROBERT T. BUCKNER

****

September 19, 1997

#103500

Q. **Please state your name for the record.**

A. My name is Robert T Buckner ("Terry").

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. **How long have you been employed in the utility industry?**

A. Approximately twenty years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS") for eight years and the First Utility District of Knox County for three years.

Q. **What is your educational background and what degrees do you hold?**

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. Would you briefly describe your responsibilities as a Regulatory Analyst since your employment with the CA?

A. I prepared testimony and exhibits as an employee with the Commission before becoming a member of the CA. My responsibilities have not changed significantly since becoming employed with the CA.

Q. What is the purpose of your testimony before the Tennessee Regulatory Authority ("TRA")?

A. The purpose of my testimony is to present the CA's recommended revenue requirement for Docket #97-00982 for Chattanooga Gas Company ("Company"). The CA is recommending a rate reduction of $1.393 million. A summary of the revenue requirement issues is found in Schedule A of my exhibit. Mr. Dan McCormac will present direct testimony regarding the forecast of revenues. Mr. Archie Hickerson, Director of the CA staff will present direct testimony and exhibits regarding the Company's proposed acquisition adjustment. Dr. Stephen Brown will present direct testimony and exhibits as to the just and reasonable cost of equity. Additionally, I will present my opinion on behalf of the CA as to the appropriate operating expenses for the attrition year October 1, 1997 to September 30, 1998 for the Company. Also, I will present my opinion as to the appropriate

calculation of other taxes, income taxes, rate base and depreciation expense for the attrition year.

Q. Please identify the issues regarding operating expenses for Chattanooga Gas Company in Docket #97-00982?

A. The CA Exhibit, Schedule 10 indicates the differences in the forecasted amounts between the CA and the Company. The operating expenses projected by the CA are $2.239 million lower than the operating expenses projected by the Company for the attrition year. The issues regarding this $2.239 million include the following: (1) the CA has excluded $1.497 million in excessive expense growth due to the allocation of charges from the Company's corporate parent, Atlanta Gas Light ("AGL"); (2) a reduction of $.227 million in forecasted expenses associated with promotional advertising; (3) a $.219 million reduction in projected uncollectible expense; (4) a reduction of $.192 million in expenses primarily due to excessive growth rates; and (5) $.142 million in rate case expense and miscellaneous income deductions. (This includes $.038 million of miscellaneous income deductions per CA Exhibit, Schedule 8, Line 10). Additionally, a reconciliation of all revenue requirement differences between the CA and the Company is provided in Buckner Exhibit, Schedule A.

Q. **Please explain your opinion as to the forecasted difference of $1.497 million in forecasted allocation of AGL expenses of the Company and the CA for the attrition year.**

A AGL performs most of the management and financial operations of the Company AGL performs these same operations for its customers in Georgia. As of June 30, 1997, AGL serves nearly 1.37 million customers in Georgia and just over 53,000 in Tennessee or 3.73% of AGL's total customers. Since AGL personnel perform the same operations for both states, their costs are allocated between the two jurisdictions. The Company has included $5.227 million of allocated operating expenses from AGL in its forecast for the attrition year. This amount is 5.13% of AGL's forecasted total of $102 million in expenses subject to allocation and is disproportionate to the number of customers in Chattanooga. In my opinion, the TRA should reject the Company's expense allocation amount because it simply seeks to impose the highest possible costs on Chattanooga consumers instead of just and reasonable costs. The CA has included in its forecast $3.730 million of allocated operating expenses from AGL, resulting in a difference of $1.497 million. The total difference in allocation is $1 497 million in the following three areas: (1) $1.253 million in allocation based on the current number of customers of the Company to total AGL; (2) $.151 million in excessive rate of return on net

investment; and (3) $.093 million of allocated AGL expenses that should be charged to non-utility operations rather than regulated ratepayers.

First, in my opinion, a change is required as to the result from the allocation methodology proposed by the Company to one based on the percentage of Company customers to the total number of customers served by AGL (3.73%). My opinion is based on several criteria.

(A) Financial: AGL's proposed forecast of charges allocated to the Company is nearly 300% higher than the 1996 amount (an increase of $3.908 million). This increase causes results that are not logical. According to the Company's accounting records, the new allocation methodology was implemented October 1, 1996. While the theoretical multi-component allocation methodology proposed by the Company seems reasonable, the practical end result of the methodology is not reasonable to the ratepayer. Mr. James E. Kissel, who filed direct testimony on behalf of the Company, explains the allocation methodology change. In his testimony, he states the following:

> "Chattanooga Gas Company is expected to see an increase of approximately $2.3 million in the total amount being allocated versus the estimated amount to be allocated using the prior method....The new methodology allocates 3.7% of the central services costs

to Chattanooga Gas Company "

As previously mentioned, the Company has forecasted a $3.908 million increase over fiscal year end 1996 (New allocation methodology over old allocation methodology). Also in contrast, AGL forecasts 5.13% of the total costs subject to allocation to be charged to Chattanooga. Mr. Kissel did not testify to the validity of the Company's forecasted allocation amount, nor is there any assurance that AGL is following Mr. Kissel's recommended allocation methodology with precision.

Further, as an offset, the Company has reduced its local employee level from an average of 127 in 1996 to an average of 91 for year-to-date May 1997. As a result, the Company realized $2.267 million in personnel related cost savings. Despite the lower number of employees, the Company's forecast of operations and maintenance expenses does not reflect a decline in expense for the attrition year, but is unjustifiably 15% higher than fiscal year ended September 30, 1996 (See Buckner Exhibit, Schedule B). Additionally, the 1996 amount is abnormally high because it includes $2.8 million of one-time employee severance expenses for the Company's restructuring. Further, AGL's 1996 annual report to its shareholders reports that, "Fiscal 1996 was a record earnings year for us." AGL is merely shifting costs previously charged to their Georgia operations to their

Tennessee operations. If a rate increase is granted from this issue, the net result is an increase in profit for AGL.

(B) Regulatory: In my opinion, the CA's recommended methodology is consistent with the findings of the preliminary draft of the TRA staff compliance audit dated July 29, 1997. It is standard practice for the operating utility companies regulated by the TRA to apply a single percentage allocation formula when allocating corporate charges. A single component allocation eliminates the potential for recovering over or under 100% of its allocated common costs. Also, this practice offers consistent treatment of costs in all jurisdictions, thereby eliminating the potential for cost manipulation between entities by AGL management. The use of a multi-component allocation method is problematic. For example, while using the multi-component method, the actual fiscal year-to-date May 1997 charges from AGL to the Company are 4.36% of the total subject to allocation and not AGL's forecast of 5.13%. If the year-to-date factor of 4.36% is applied to AGL's forecasted $102 million subject to allocation, then the allocated expense is $.780 million in lower expenses. Also, AGL has reduced its level of employees by over 70 since year end December 31, 1996. Consequently, if the TRA approves the Company's proposed allocated amount for the attrition year, the Company will over recover costs using its current

allocation methodology. When the single allocation percent of 3.73% based on number of customers is applied, the allocated charges from AGL are lowered by $1 253 million or an additional $ 473 million in lower allocated expenses.

Finally, if either the Georgia and the Tennessee regulatory agencies set rates using other than rate base regulation, i.e. incentive regulation, then a temptation exists for the Company to maximize costs in one jurisdiction over another.

(C) Practicality: The use of a single allocation component makes a cleaner trail to audit and to verify the accuracy of the charges allocated to both Chattanooga and Georgia customers. A regulatory agency usually has limited time and resources to validate the financial records of the Company. The Company's external auditors rarely, if ever, certify the accuracy of charges between jurisdictions, but usually examine only the Company's operations in total. Consequently, the Company's use of a multi-component allocation method makes the regulator's audit exponentially more difficult. If the multi-components change from month to month, then the regulator is forced to examine every employee's record of time, every paid invoice and every financial accounting change for its veracity. The use of a multi-component allocation method significantly improves the regulator's oversight abilities.

(D) Equity By using a single component allocation method, every customer bears equally the charges from corporate's common costs. When dealing with common or joint costs, there is no way to pinpoint the party that actually causes the cost. By definition, common or joint cost is not associated with any particular party. It is a fine notion in attempting to pinpoint every cost causation to a particular customer or a group of customers, but that is not practical. The TRA's goal should be one of providing excellent utility service for every customer at a just and reasonable price. For example, if a main is in need of repair for a particular neighborhood, all the customers of the Company bear the cost in repairing the main, not only the neighborhood. Further, when the Company expands the service, all of the customers bear the cost of the expansion.

Secondly, the forecasted AGL allocations for the attrition year include a return component on the net investment used for both jurisdictions (For example, the AGL corporate office building). This return amount is calculated using the Georgia Public Service Commission authorized rate of return of 9.32% in AGL's last rate case. By updating the rate of return to the just and reasonable rates at this time, based upon the opinion of Dr. Stephen Brown, the CA recommends 8.85% as the rate of return using the net investment of April 1997. Based upon that just and reasonable return, the rate of

return component is reduced by $.151 million.

Finally, AGL has not allocated any of its corporate office costs to non-utility operations. This finding was made in the previously mentioned TRA staff compliance audit report. The Company has stated in response that it will change its allocation to non-utility operations beginning October 1, 1997. This change results in a reduction in allocated expenses of $92,503.

In summary, it is germane to the TRA and the ratepayer that the allocation of AGL expenses should be based on a consistent methodology. Most importantly, the expenses borne by the ratepayer must be just and reasonable. Although the Company trumpets its efficiency from restructuring, the results are not evident in what AGL is asking the customer to pay. Finally, AGL's proposed rates should not be granted to placate Company management, but only if they are just and reasonable.

Q. Please explain the forecasted difference in sales promotion expense amounting to $.227 million.

A. The CA has excluded $.227 million in sales promotion expenses. The sales promotion expense proposed by the CA meets the standard criteria of 5% of revenues in determining the amount of expense to allow for advertising. This standard criteria was set in Tennessee

Public Service Commission ("TPSC") Docket U-85-7355 for Nashville Gas Company as a surrogate for actually identifying the advertising expense by category because most of the advertising expense was promotional in nature. This is consistent with positions taken by the Commission Staff in subsequent gas company rate cases i.e. United Cities Gas Company, Docket #92-02987. Further, regarding advertising expenses Commission rule *1220-4-5- 45* states, "A utility may not recover from any person other than their shareholders (or other owners) any direct or indirect expenditure for promotional or political advertising. The term 'promotional advertising' means any advertising for the purpose of encouraging any person to select or use gas service or additional gas service or the selection or installation of any appliance or equipment designed to use gas service."

The TPSC found the .5% to be consistent with the rule and departure from the policy is inappropriate under existing legal standards which require the agency to follow existing rules and practices.

Q. Please explain the forecasted difference in uncollectible expense of $.219 million.

A. The CA's uncollectible expense for the attrition year was calculated

based on the Company's most recent seven years and eight months experience of net write-offs. The CA uncollectible expense amount for the attrition year is $165,968. This amount is $219,051 lower than the Company's amount of $385,019 which was based on a 12 month average from March 1996 to February 1997. The Company's selected time period is an aberrant and abnormal time period for forecasting purposes and is more than double the historical amounts for the previous six fiscal years. The Company has not presented substantial and material evidence which shows that the expense will continue at that unusual rate. Further, the Company forecasted amount is not indicative of even their current expense. The Company booked $14,293 for uncollectible expense in May 1997.

Q. Please explain the difference in the forecasted expense growth rates of the Company and the CA for the attrition year.

A. The Company has used a compound customer and inflation ("CPI") growth rate of 15.62% for the majority of the operating expense accounts excluding salaries and wages. The Company grew these accounts for the test year, the fiscal year ended September 30, 1996, by 15.62% to arrive at their attrition year amounts. It is generally accepted that CPI overstates inflation. Because use of the CPI overstates inflation, it creates more than a just and reasonable

expense

In my opinion and the opinion of most experts the GDP is a better indicator than CPI. The CA used one half of the annual customer growth rate of 4.65% and an annual inflation ("GDP") rate of 2.36% which generates a compound growth rate of 7.25% from the nineteen months ended May 31, 1997 through September 30, 1998. The information used to determine the CA's inflation factor was taken from the publication "Blue Chip Indicators". The difference between GDP and CPI results in $.057 million in lower operations and maintenance expenses. Also, the CA used a later test period from June 30, 1996 through May 31, 1997. This period is used because it is more indicative of the Company's post-restructuring costs and of their current cost of operation. The annual customer growth rate was based on the Company's projections of customer growth. Additionally, the CA priced out employee's salaries and wages for the attrition year resulting in $.052 million lower expense. Consequently, it was not necessary to grow salary and wage expense from the test period using an inflation factor. The cumulative effect of the difference in the compound inflation rates, customer growth rates and test period differences amounts to $.192 million.

Q. Please explain the difference in the forecasted rate case expenses and miscellaneous income deductions of the Company and the CA for the attrition year and your opinion on these differences.

A. The CA included $144,500 of Company anticipated costs for this rate filing to be amortized over three years or $48,167 for the attrition year plus one year's amortization of Docket #95-02116 at $16,167. The excess expense difference between the CA calculated amount and the Company projection amounts to $.104 million. The Company has taken the fiscal 1996 year end amount and has increased it for "CPI" inflation and customer growth. The Company's adjustment has no relationship to historic or prospective amortization amounts from rate filings.

Finally, the CA disallowed approximately $37,540 in miscellaneous expenses as proposed by the Company which are not allowed for use in setting rates. In my opinion, the CA position on this item is consistent with previous positions taken by the TRA Staff.

Q. Please identify the issues and your opinion regarding other taxes and income taxes for Chattanooga Gas Company in Docket #97-00982?

A. The CA Exhibit, Schedule 11 indicates the differences in the forecasted amounts between the CA and the Company. In my

opinion, the projected other taxes are $ 401 million lower than the tax amounts projected by the Company for the attrition year. My opinion regarding this $.401 million includes the following: (1) I exclude approximately $.207 million in excessive property tax expense; (2) a reduction of $.151 million in forecasted Tennessee gross receipts tax expense; (3) a reduction of $26,340 in forecasted Tennessee state franchise tax expense; (4) approximately $6,800 in lower payroll taxes and the TRA inspection fee; and (5) income taxes per Schedule 12 are due to the difference in taxable net operating income.

Q. Please explain your opinion as to the forecasted difference in other taxes of approximately $.401 million.

A. The Company has erroneously mixed un-equalized property assessment value with equalized property assessment value in its calculation of average property assessment growth from 1991 through 1996. The Company's use of assessment history, beside its inherent error in calculation, does not reflect current trends. I calculated property taxes using the 1996 tax rates and equalized property assessment values which reflects the most recent historical increases (1995-1996). This results in a $.217 million adjustment to remove the overstated projected property tax expense proposed by the Company.

In addition, the Company has used a five year average of effective Tennessee State Gross Receipts Tax rates to calculate the amount of Tennessee Gross Receipts Tax for the attrition period. The Company's use of a five year average does not reflect the current effective tax rate for use in setting rates and consequently overstates the Tennessee Gross Receipts Tax. For example, the Gross Receipts Tax to be paid is offset by the amount of Tennessee Franchise and Excise Tax paid in the prior year. The Excise tax is calculated based on normalized tax depreciation. The use of accelerated tax depreciation reduces the Tennessee excise tax, but conversely increases the Tennessee Gross Receipts Tax. For setting rates, both the Company and the CA have ignored accelerated tax depreciation rates for calculating Tennessee Excise Tax. The Company, however, has used the normalized tax depreciation benefit when calculating its Gross Receipts Tax. The difference in calculated amounts between the Company and the CA amounts to $.151 million for the attrition year.

The Company has included an acquisition adjustment in its calculation of Tennessee State Franchise Tax. This is an inappropriate inclusion for calculating franchise tax expense in setting rates. I excluded this amount resulting in $26,340 lower franchise tax expense.

Additionally, the payroll taxes for the attrition year are overstated by the Company by approximately $4,141 due to an overstated salary and wage calculation by the Company.

Finally, the Company has overstated the TRA inspection fee by $2,746 primarily due to overstated revenues for the inspection fee period.

Q. Please explain the forecasted difference in income taxes.

A. The difference in the CA and Company's income taxes is due to lower operating expenses by the CA and the difference in capital cost, specifically the cost of debt.

Q. Please define, "Rate Base."

A. Simply put, Rate Base is the net investment upon which the Company is allowed to earn a just and reasonable rate of return. A summary comparison of the rate base amounts for both the CA and the Company is found in the CA Exhibit, Schedule 3.

Q. Please explain you opinion and the forecasted difference in Rate Base.

A. The CA Rate Base is $6.783 million lower than the Company and my opinion relies on the following:

Net Acquisition Adjustment - The CA has excluded $13.356 million Acquisition Adjustment and $4 196 million of Accumulated Amortization of Acquisition Adjustment for a net reduction in rate base of $9 160 million. As previously mentioned, Mr. Archie Hickerson, Director of the CA will address these amounts in his direct testimony.

Working Capital - The CA is $1.636 million higher than the Company primarily due to an erroneous customer deposit amount by the Company in its forecast. According to the Company, there is a transposition error in their filing of forecasted customer deposits.

Net Utility Plant in Service - The CA used a simple average rather than a thirteen month average to develop the two major Rate Base components, Utility Plant and Service and Accumulated Depreciation. This amounts to the CA being a net $.691 million higher than the Company.

Q. How did you calculate depreciation expense for the attrition year?

A. The average attrition year plant balances were multiplied by the Company proposed depreciation rates. I am not expressing an opinion on the accuracy of the Company's request to reduce the composite depreciation rate from 3.66% to 3.61%. The CA did not

have sufficient time nor the resources to investigate the reasonableness of the Company proposed depreciation rates. The calculated result, however, is $4.811 million in depreciation expense for the attrition year. This amount is $9,875 lower than Company amount. This amount is due to the CA's exclusion of depreciation expense on Land and Land Rights as proposed by the Company. In my opinion, Land and Land Rights should not be depreciated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

TENNESSEE PUBLIC SERVICE COMMISSION

In Re Petition of United Cities Gas Company to Place Into Effect a Revised Natural Gas Tariff

Docket No 95-02258

****

DIRECT TESTIMONY

OF

R TERRY BUCKNER

****

September 25, 1995

Q. **Please state your name for the record.**

A. My name is R. Terry Buckner.

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. **How long have you been employed in the utility industry?**

A. Approximately eighteen years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS") for eight years and the First Utility District of Knox County for three years.

Q. **What is your educational background and what degrees do you hold?**

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. **Would you briefly describe your responsibilities as a Regulatory Analyst since your employment with the CA?**

A. I prepared testimony and exhibits as an employee with the

Commission before becoming a member of the CA. My responsibilities have not been altered significantly since my employment change.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present information to the Commission on the appropriate operating expenses other than depreciation and salaries and wages for the attrition year December 1, 1995 to November 30, 1996 for United Cities Gas Company ("Company"). Additionally, I will present the CA's calculation of other non-payroll taxes and income taxes for the attrition year.

Q. Please identify the issues regarding operating expenses for United Cities Gas Company in Docket #95-02258?

A. The CA Exhibit, Schedule 5, indicates the differences in the forecasted amounts between the CA and the Company. The non-payroll operating expenses projected by the CA are $3.166 million lower than the non-payroll operating expenses projected by the Company for the attrition year. The eight principle issues regarding this $3.166 million include the following: (1) The CA Exhibit, Schedule 4, Line 11 has included $1.502 million in annual savings as found in the Management Audit of the Company by The Liberty Consulting Group ("Liberty"). Liberty was employed at the direction of the Commission to conduct the management audit of the Company

in Docket #92-02987. The Commission ordered in Docket #92-02987 that the results of the audit be considered in the next rate filing which is this Docket #95-02258. Liberty has completed the audit and has provided the report to the Commission. Liberty representatives will testify as to the validity of the annual savings amount. The CA relied on their expertise in incorporating the identified annual savings in its forecast for the attrition year as found in Liberty's management audit report; (2) The Company has overstated $.694 million in forecasted non-payroll operating expenses originating from the CA's test period reconciliation; (3) The Company overstated $.390 million in projected employee health insurance; (4) The CA recommends $.334 million in disallowed and non-recurring expenses; (5) The CA inflation and customer growth rate used for non-payroll expenses is $.244 million in higher than the Company for the attrition year; (6) The CA proposes a disallowance of $.198 million in forecasted sales promotion expense; (7) The Company has improperly included $.189 million of interest on customer deposits with operating expenses. The CA has recognized this item for presentation purposes as interest expense and as a separate line item in the comparative income statement; (8) The CA has disallowed Company adjustments of $.103 million in storage expense, postage expense, and management audit amortization expense.

Q. Please explain the $.694 million difference in the test period non-payroll operating expense amount of the Company and the CA used in forecasting non-payroll expenses for the attrition year.

A. The Company has over-allocated non-payroll costs to Tennessee operations for the test year 1994 by $.694 million. Approximately $.656 million of this amount is classified in the General and Administrative expenses. The Company has four major divisions of operation and allocation of costs: (1) The Division Corporate Office; (2) The Illinois/Tennessee Division; (3) The Virginia/East Tennessee Division; and (4) The Tennessee Division. Tennessee operations receive an allocation of payroll and non-payroll expenses from each Division for reporting purposes and setting rates. The allocation amounts in the Company's filing are not consistent with the actual test period 1994 Divisional income statements ("R50400") furnished to the CA by the Company. Consequently, the allocation percentages used by the Company in its rate filing to allocate costs to Tennessee are overstated and are not consistent with the actual amounts or the factors used in Commission Docket #92-02987, the last rate increase for the Company.

Q. Please explain the forecasted difference in employee health insurance amounting to $.390 million.

A. The Company has proposed an increase of nearly 50% in health

insurance expense from 1994 to the attrition year. A review of actual growth has been well below this level of growth. The medical claims furnished to the CA have grown closer to the annual inflation rate of 2% to 3% for 1994 over 1993. Additionally, year to date 1995 annualized amounts are approximately at the same level as 1994.

Q. Please explain the forecasted difference in disallowed and non-recurring amounts of $.334 million.

A. The Company has included $.334 million in expenses from the 1994 test period which are not valid for setting rates or are non-recurring in nature. These expenses include the following: (1) expenses for Non-competition agreements primarily with Union Gas Company incurred during acquisition of their natural gas systems. These payments in effect represent a premium paid in excess of the book value of the Union Gas Company and are not a cost of providing utility service to Tennessee customers. This position is supported by Liberty. In its management audit report, Liberty agrees that this cost should not be recognized for setting rates (See pages II-45,48). Further, the Commission has historically recommended that these costs be borne by the shareholder of the Company and not the ratepayer; (2) expenses for an equity funding fee were also excluded in the CA's attrition year forecast. Simply put, the Company relies upon the earnings of an affiliated company, Energy Company, in order to issue

utility bonds, therefore, justifying a fee. However, the affiliated Energy company generates most of its earnings from captive financing agreements with the Company. The Commission Staff has historically not allowed this expense in setting rates. Additionally, Liberty recommended that this equity funding fee be eliminated (See pages II-44,45); and (3) The CA excluded one-time expenses incurred by the Company in 1994 through a class-action lawsuit alleging price fixing in East Tennessee in the 1980's. In February 1995, the Company reached a settlement agreement with the Tennessee Attorney General in the amount of $80,000. This settlement was pending the United States District Court's approval according to the Company's audited 1994 annual report to the stockholders. This is not a normal or recurring expense.

Q. Please explain the forecasted difference in expense growth rates amounting to $.244 million.

A. The Company has proposed a growth factor of 6.71% to increase most of its non-payroll operating expenses. The CA used a compound growth factor of 9.81% from the twelve months ended December 31, 1994 to November 30, 1996. The CA used an annual weighted customer growth rate of 2.5% and an inflation rate of 2.56%. The information used to determine the CA's inflation factor was taken from the publication *Blue Chip Indicators*. The cumulative

effect of the difference in the compound growth rate of non-payroll expense amounts to $.244 million more than the Company.

Q. Please explain the forecasted difference in sales promotion expense amounting to $.198 million.

A. The CA has excluded $.198 million in sales promotion expenses. The sales promotion expense proposed by the CA meets the standard criteria of .5% of revenues in determining the amount of expense to allow for advertising. This standard criteria was set in Commission Docket U-85-7355 for Nashville Gas Company and is consistent with positions taken by the Commission Staff in subsequent gas company rate cases i.e. United Cities Gas Company, Docket #92-02987. In addition, Commission rule *1220-4-5- 45* states, "A utility may not recover from any person other than their shareholders (or other owners) any direct or indirect expenditure for promotional or political advertising. The term 'promotional advertising' means any advertising for the purpose of encouraging any person to select or use gas service or additional gas service or the selection or installation of any appliance or equipment designed to use gas service." While this rule prohibits promotional advertising, safety and informational advertising is allowed. In previous years, disagreements have arisen as to the proper classification of advertising expenses. The .5% allowance threshold was adopted in lieu of specifically identifying

the type of advertising expense.

Q. Please explain the forecasted difference in storage expense, management audit amortization, and postage expense amounting to $.103 million.

A. Storage expense amount of $42,334 is excluded by the CA because the test year amount in the Company's exhibit (See Exhibit 7, Page 1, Line 7, Column 2) does not reconcile to the amount in the Company's corporate division income statement.

Also, the CA has amortized the management audit expense over a four year period. A four year period more adequately reflects the potential life of the management audit investment cost. This is consistent with the Commission Staff recommended amortization period as stated in their compliance audit report dated September 13, 1995. In the Company's rate filing, an amortization period of three years was used resulting in excess expense for the attrition year of $29,791.

Finally, the Company has included a $31,137 increase for postage expense. As previously mentioned, the CA has already recognized this increase through the growth factor applied to all non-payroll expenses. (See p. 7, Line 2).

Q. Please identify and explain the issues regarding other taxes and income taxes for United Cities Gas Company in Docket #95-

02258.

A. The CA Exhibit, Schedule 8 indicates the differences in the forecasted amounts between the CA and the Company. Other taxes are a separate tax category for classification purposes and are non-income taxes. The other taxes projected by the CA are a net $60,000 lower than the tax amounts projected by the Company for the attrition year. The issue regarding this $60,000 include primarily the calculated net differences in gross receipts tax, property tax and franchise tax.

Income taxes are higher per Schedule 10 primarily due to the difference in taxable net operating income. However, based on the capital structure of Dr. Brown, the CA has included $.600 million in additional interest expense in its calculation of income taxes, Schedule 9, Line 15. This inclusion reduces income taxes, but also the CA has included permanent differences, items which are not deductible for income tax purposes, of $.164 million which increases income taxes. These permanent differences have apparently been excluded by the Company in its tax calculation.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name for the record.

A. My name is R. Terry Buckner.

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

A. I am employed by the Consumer Advocate Division ("CA") in the State of Tennessee Attorney General's Office as a Senior Regulatory Analyst.

Q. How long have you been employed in the utility industry?

A. Approximately eighteen years. Before my employment with the Attorney General, I was employed with the Tennessee Public Service Commission ("Commission") as a financial analyst for approximately six years. Prior to my employment with the Commission, I was employed by Telephone and Data Systems ("TDS") for eight years and the First Utility District of Knox County for three years.

Q. What is your educational background and what degrees do you hold?

A. I have a Bachelors degree in Business Administration from the University of Tennessee, Knoxville with a major in Accounting. I am also a Tennessee Certified Public Accountant and a member of the American Institute of Certified Public Accountants.

Q. Would you briefly describe your responsibilities as a Regulatory Analyst since your employment with the CA?

A. I prepared testimony and exhibits as an employee with the

Commission before becoming a member of the CA. My responsibilities have not been altered significantly since my employment change.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present information to the Commission on the appropriate operating expenses other than depreciation for the attrition year October 1, 1995 to September 30, 1996 for Chattanooga Gas Company ("Company"). Additionally, I will present the CA's calculation of other taxes and income taxes for the attrition year.

Q. Please identify the issues regarding operating expenses for Chattanooga Gas Company in Docket #95-02116?

A. The CA Exhibit, Schedule 10 indicates the differences in the forecasted amounts between the CA and the Company. The operating expenses projected by the CA are $1.854 million lower than the operating expenses projected by the Company for the attrition year. The issues regarding this $1.854 million include the following. (1) the CA has excluded approximately $.577 million in excessive expense growth and inappropriate expenses for setting rates for the ratepayer; (2) a reduction of $.398 million in forecasted salaries and wages associated with advertising; (3) a reduction of $.280 million in forecasted medical insurance; (4) $.248 million reduction in projected

uncollectible expense, sales promotion expense, management audit expense, and miscellaneous expense; (5) $.194 million in legal and rate case expense; and (6) $.157 million in payroll clearings.

Q. Please explain the difference in forecasted expense growth of the Company and the CA for the attrition year.

A. The Company has used a compound customer and inflation growth rate of 18.06% for the majority of the operating expense accounts excluding salaries and wages. The CA used an annual customer growth rate of 4.65% and an annual inflation rate of 2.56% which generates a compound growth rate of 9.89% from the twelve months ended September 30, 1994 through September 30, 1996. The information used to determine the CA's inflation factor was taken from the publication "Blue Chip Indicators". The annual customer growth rate was based on the Company's projections of customer growth. The cumulative effect of the difference in the compound growth of non salary and wage expense amounts to $.310 million.

The CA's calculation of salaries and wages is approximately $.220 million lower than the Company. This difference is due to overstatement of salaries and wages in the Company's filing when reconciled with the price-out of employee's salaries, the exclusion of one employee, and lower salary increases for management and non-union supervisory personnel. The Company included an employee

who is no longer with the organization in its projection of salary and wages. Additionally, the Company projected annual increases of 5% and 4.5% for it's non-union management and supervisory personnel. The CA limited the increase for these employees to a 4% annual increase, the same level agreed to by the union supervisory personnel in year one of their contract.

The remaining $47,000 difference is due to the erroneous exclusion by the Company of flex vacation deduction amounts of approximately $28,000; and approximately $19,000 of under-allocated costs to non-regulated operations and capitalization.

Q. Please explain the forecasted difference in sales promotion salaries and wages expense amounting to $.398 million.

A. The CA has excluded $.398 million in sales promotion salaries and wage expenses. The sales promotion expense proposed by the CA meets the standard criteria of .5% of revenues in determining the amount of expense to allow for advertising. This standard criteria was set in Commission Docket U-85-7355 for Nashville Gas Company and is consistent with positions taken by the Commission Staff in subsequent gas company rate cases i.e. United Cities Gas Company, Docket #92-02987. Further, regarding advertising expenses Commission rule *1220-4-5- 45* states, "A utility may not recover from any person other than their shareholders (or other

owners) any direct or indirect expenditure for promotional or political advertising. The term 'promotional advertising' means any advertising for the purpose of encouraging any person to select or use gas service or additional gas service or the selection or installation of any appliance or equipment designed to use gas service."

Q. Please explain the forecasted difference in employee health and life insurance expense of $.280 million.

A. The Company erroneously used the projected 1997 amount for employee insurance expense rather than the appropriate 1996 per Company workpapers. Further, the Company failed to allocate a portion of these expenses to capitalization and non-regulated operations. The correction of these oversights amounts to approximately $.280 million.

Q. Please explain the forecasted difference in uncollectible expense, sales promotion expense, and management audit expense accumulating to $.248 million.

A. The CA's uncollectible expense for the attrition year was calculated based on the most recent five year history of net write-offs. The CA amount is approximately $65,000 lower than the Company's amount which excludes an abnormally high recovery amount for 1994, but fails to exclude the abnormally high write-off as well. The CA amount reflects both exclusions.

The CA has excluded $90,226 in additional Company proposed sales promotion expenses. As previously discussed, the sales promotion expense proposed by the CA meets the standard criteria of .5% of revenues in determining the amount of expense to allow for advertising. This standard criteria was set in Commission Docket U-85-7355 for Nashville Gas Company and is consistent with positions taken by the Commission Staff in subsequent gas company rate cases i.e. United Cities Gas Company, Docket #92-02987.

Also, the CA has amortized the management audit expense over a four year period. This is consistent with the Commission Staff recommended amortization period as stated in their compliance audit report dated August 28, 1995. In it's rate filing, the Company amortized the management audit expense over a two year period resulting in excess expense of $49,347.

Finally, the CA disallowed approximately $42,000 in miscellaneous expenses as proposed by the Company which are not allowed for use in setting rates. The CA position on this item is consistent with previous positions taken by the Commission Staff.

Q. Please explain the forecasted difference in legal and rate case expense of $.194 million.

A. The Company included legal costs for Federal Regulatory Energy Commission ("FERC") orders incurred in or prior to the test year and

have no basis for inclusion in the attrition year. The CA included $48,500 of anticipated costs for this rate filing to be amortized over three years or $16,167 for the attrition year. The excess expense difference between the CA calculated amount and the Company projection amounts to $.194 million.

Q. Please explain the forecasted difference in payroll clearings of $.157 million.

A. The Company has included in its calculation of non-salary and wage expenses, $.157 million in payroll clearing. The Company calculated its attrition year salaries and wages expense including amounts charged to clearing accounts. Some employees charge their work time to a clearing account. A portion of the clearing account amount is redistributed to expense accounts. The redistributing or clearing process allocates payroll charged to clearing accounts to an expense account based on salaries and wages charged directly to expense accounts. However, through the Company's accounting processes, the payroll clearing amount is recognized as non-payroll dollars. The Company has in effect double-counted the $.157 million payroll clearing dollars by including them in their salaries and wages expense calculation and also in their calculation of non-salary and wage expenses.

Q. Please identify the issues regarding other taxes and income taxes for Chattanooga Gas Company in Docket #95-02116?

A. The CA Exhibit, Schedule 11 indicates the differences in the forecasted amounts between the CA and the Company. The other taxes projected by the CA are $.400 million lower than the tax amounts projected by the Company for the attrition year. The issues regarding this $.400 million include the following: (1) the CA has excluded approximately $.200 million in excessive property tax expense; (2) a reduction of $.106 million in forecasted Tennessee gross receipts tax expense; (3) a reduction of $45,550 in forecasted Tennessee state franchise tax expense; (4) approximately $30,000 in lower payroll taxes; and (5) income taxes per Schedule 13 which are primarily due to the difference in taxable net operating income.

Q. Please explain the forecasted difference in other taxes of approximately $.400 million.

A. The Company has assumed a significant property tax rate change for Hamilton County during the attrition year. There is no evidence to support this rate change. Further, the composite tax rate for the Company has not changed significantly over the last three years. The CA has calculated property taxes using the 1994 tax rates and property assessment values which reflects recent historical increases. This results in $.200 million in overstated projected property tax

expense by the Company.

The Company has used a five year average of effective Tennessee State Gross Receipts Tax rates to calculate the amount of Tennessee Gross Receipts Tax for the attrition period. The effective tax rate has declined by 20% over the last five years. The Company's use of a five year average does not reflect the current effective tax rate and consequently overstates the Tennessee Gross Receipts Tax. The CA has used an average of actual and projected gross receipts for the attrition year at the actual tax rate less 1994 estimated franchise and excise taxes. The difference in calculated amounts between the Company and the Staff amounts to $.107 million for the attrition year.

The Company has included an acquisition adjustment in its calculation of Tennessee State Franchise Tax. This is an inappropriate inclusion for calculating franchise tax expense in setting rates. The CA has excluded this amount resulting in $45,550 lower franchise tax expense.

Additionally, the payroll taxes for the attrition year are overstated by approximately $30,000 due to an overstated salary and wage calculation by the Company.

Q. Please explain the forecasted difference in income taxes.

A. The difference in the CA and Company's income taxes is due to lower operating expenses by the CA and the difference in capital structure, specifically the cost of debt.

Q. Does this conclude your testimony?

A. Yes, it does.